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Greenhouse Gas
Prevention of Significant Deterioration
Permit Application for
Polyethylene Unit

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Mont Belvieu, Texas

Revised March 2013

Prepared by

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SECTION 1
INTRODUCTION

ExxonMobil Chemical Company (ExxonMobil) owns and operates a polyethylene plant in Mont Belvieu, Chambers County, Texas known as Mont Belvieu Plastics Plant (MBPP). ExxonMobil is hereby requesting an authorization to construct new equipment at the MBPP which will allow for an increase in polyethylene production, herein referred to as the proposed project.

1.1 Background

Increased North American shale gas production is positive news for the U.S. economy and, in particular, U.S. petrochemical manufacturers who have benefited not only from lower energy costs, but also from the increased availability of advantaged light feedstock such as ethane – both of which lower overall chemical production costs. This has resulted in numerous announcements of North American ethane cracking studies.

ExxonMobil's U.S. Gulf Coast manufacturing facilities are well-positioned to capitalize on the growing U.S. ethane infrastructure, to expand our domestic capability to produce ethylene and polyethylene, and to supply our high quality commodity and specialty products to customers around the world. The proposed investment reflects ExxonMobil's continued confidence in the natural gas-driven revitalization of the U.S. chemical industry.

If ExxonMobil elects to proceed with this project, it could greatly benefit local economies by creating new jobs and economic growth in the U.S. Gulf Coast region. The project is expected to create about 350 full-time jobs and about 10,000 temporary construction jobs; and would be constructed in and integrated into existing ExxonMobil facilities, taking advantage of existing energy infrastructure. It is also estimated that an additional 3,700 permanent jobs would be created in the local community through multiplier effects.

1.2 Purpose of Request

The MBPP is an existing major source as defined within the Federal Prevention of Significant Deteriorations (PSD) Permit Program. Therefore, physical changes and changes in the method of operation are potentially subject to PSD permitting requirements. The proposed project will trigger PSD review for Greenhouse Gas (GHG). The permit application has been prepared based upon EPA's "New Source Review Workshop Manual" and additional GHG guidance. This permit application is submitted pursuant to EPA's Federal Implementation Plan Regarding Texas' Prevention of Significant Deterioration Program for certain stationary sources that emit greenhouse gases in Texas. 75 Fed. Reg. 82430 (December 30, 2010); 40 CFR 52.2303(d).

1.3 Facility Information

The MBPP is located at 13330 Hatcherville Road, Mont Belvieu, Texas. Figure 1-1 at the end of this section presents the facility location relative to nearby topographic features. This map is based on a United States Geological Survey (USGS) quadrangle map. As indicated by the area map, no schools are located within 3,000 feet of the facility. Figure 1-2, also located at the end of this section, is the facility plot plan showing the location of the emission points associated with the proposed project.

1.4 Federal GHG Permitting Applicability

The MBPP is an existing major source for all criteria pollutants and has potential to emit (PTE) for GHG greater than 100,000 tons per year (tpy) on a Carbon Dioxide-equivalent (CO_2e) basis and greater than 100 tpy on a mass basis. GHG emissions from the proposed project are Carbon Dioxide (CO_2), Methane (CH_4), and Nitrous Oxide (N_2O), and are expressed as CO_2e. The project GHG emissions from new and modified sources are estimated to be 132,807 tons of CO_2e annually; therefore, the project triggers PSD review for GHG emissions.

Any creditable GHG emissions decreases in the contemporaneous period have not been relied upon for the proposed project. Because an air quality impact analysis is not required for GHG emissions and inclusion of contemporaneous GHG emissions increases and decreases would not change the scope of the analyses required for issuance of the permit, both the PSD applicability determination and the subsequent permit application requirements are complete without a full contemporaneous netting analysis. Refer to Table 1-1 at the end of this section for a summary of the proposed project's GHG PSD applicability.

1.5 Application Contents

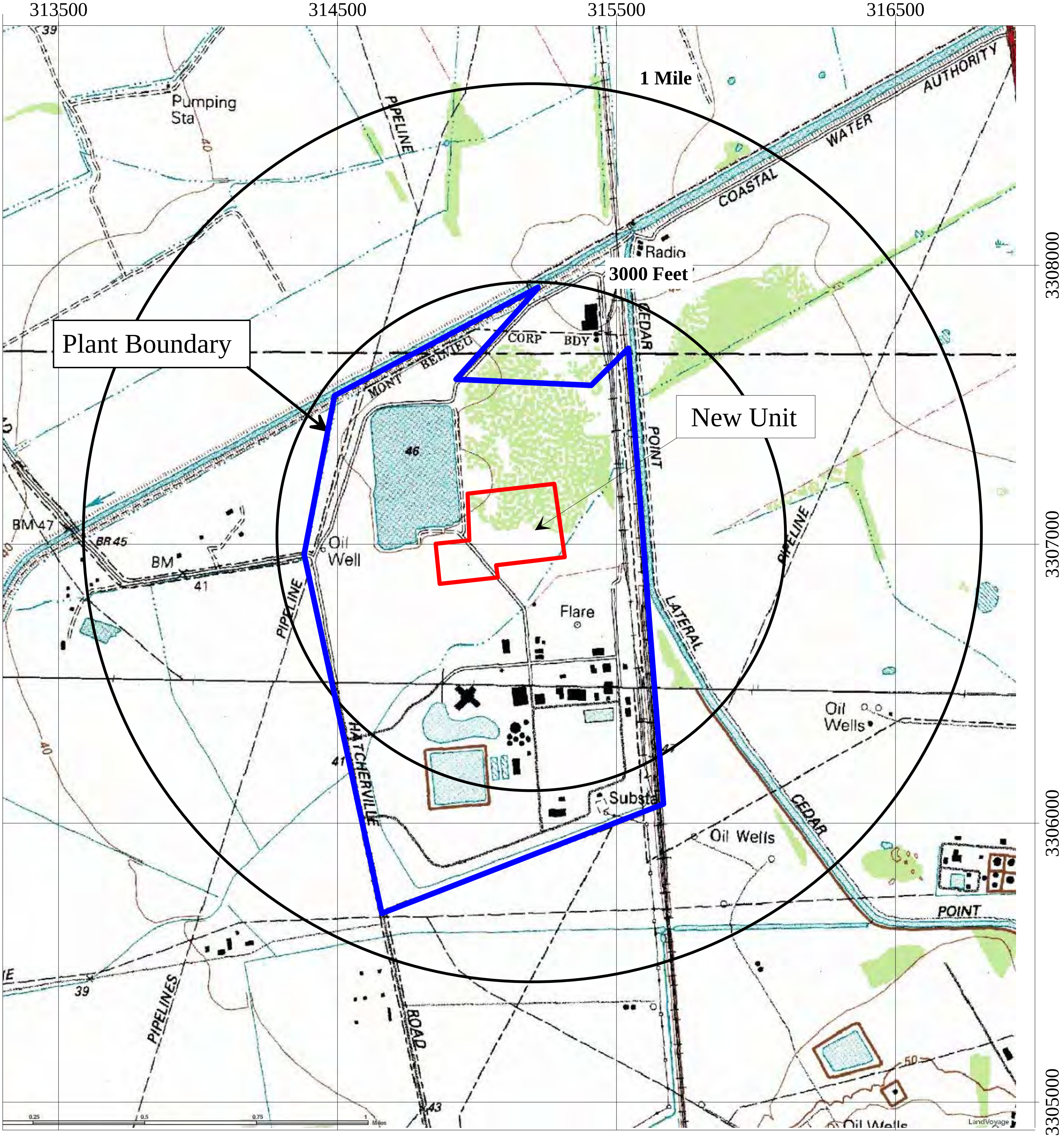
Key components of this application are organized as follows:

- An area map and plot plan are provided at the end of Section 1;
- A project description is included in Section 2;
- Emission rate calculation methodologies are discussed in Section 3;
- Best Available Control Technology (BACT) analysis is discussed in Section 4;
- Other PSD requirements are discussed in Section 5;
- Considerations for granting a permit are presented in Section 6;
- Other administrative information is contained in Section 7;
- Appendix A represents emission calculations tables; and
- Appendix B contains the RACT/BACT/LAER Clearinghouse analysis.
- Appendix C contains information pertaining to emission unit work practice standards, operational requirements, and/or monitoring.

Table 1-1 GHG PSD Applicability Summary

	POLLUTANTS	
	GHG[1]	CO_2e
Nonattainment? (yes or no)	No	
Existing site PTE (tpy)?	>100	>100,000
Proposed project emission increases (tpy)	130,364	132,807
Is the existing site a major source[2]? If not, is the project a major source by itself[2]? (yes or no)	Yes	
If site is major, is project increase significant?	Yes	
Net contemporaneous change, including proposed project (tpy)	>100	>75,000
FNSR APPLICABLE? (yes or no)	Yes (PSD)	
Estimated start of construction?	03/01/2013	
Estimated start of operation?	2Q 2016	

[1] Sum of the mass emissions in tpy of CO_2, N_2O, and CH_4 for the proposed project.
[2] PSD thresholds are found in 40 CFR § 51.21(49)(v).



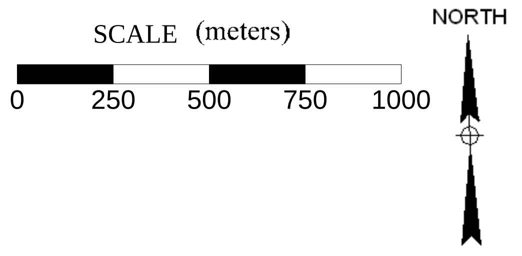


FIGURE 1-1
AREA MAP
ExxonMobil Chemical Company
Mont Belvieu Plastics Plant

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DATE:	March 2013
PROJECT:	55-6-12
FILE NAME:	Area Map.srf

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Drawing: Plot Plan.dwg	FIGURE 1–2
Revision #: 2	FACILITY PLOT PLAN
Date: December 2012	ExxonMobil Chemical Company
Project #: 55–6–12	MBPP – Expansion

SECTION 2
PROJECT DESCRIPTION

2.1 Process Description

This section provides a description of the proposed Polyethylene (PE) Unit at the ExxonMobil Chemical Company's Mont Belvieu Plastics Plant (MBPP).

The MBPP PE Unit will manufacture polyethylene resin (plastics) using low pressure, gas phase fluidized bed reactors. The proposed facilities include feed purification, polymerization, resin degassing, additives addition, pelletization, blending, storage and shipping.

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 poisons 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 a multi-point ground flare (MPGF). The MPGF will manage vent streams during periods of high load. A very small amount of residual hydrocarbon remains in the resin after purging. Liquid and dry additives are added to the granular product in accurately metered concentrations.

Granular resin is air-conveyed from the purger area into silos known as 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. Residual hydrocarbon that may evolve 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. Auxiliary systems include a cooling tower, steam boilers, and wastewater.

There will be miscellaneous vent groups associated with the new PE unit as follows:

A. Miscellaneous vent groups emitting VOC and particulate matter emissions which include:

   - Loadout sources
   - Pellet product sources
   - Bagging filter system
   - Finishing and packaging building fugitives

B. Miscellaneous vent groups emitting only particulate matter emissions which include:

   - Additive sources
   - Catalyst transfer sources

Figure 2-1 presents a simplified process flow diagram (PFD) for the proposed project.

2.2 Description of New Facilities

The following subsections provide a brief description of the emission sources from the proposed project. Design capacity is included in the subsections below or Appendix A and an operating schedule is included in Table 7-1 of this application for each of the proposed sources.

2.2.1 Regenerative Thermal Oxidizer

The new regenerative thermal oxidizer (RTO) (EPN: RUPK71) will control the residual VOC emissions from the powder hopper bag filter, conveying air vents and extruder feed vents, all of which typically have less than 130 ppmv of residual hydrocarbons. Supplemental fuel is added to the stream during start-up to ensure sufficient heating value.

2.2.2 Vent Collection System

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 controlled 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. Figure 2-2 contains a simplified schematic depicting the new control system for the vent collection system.

The Vent Collection System is designed to handle predominantly hydrocarbon streams in direct contact with the process (enclosed polymerization area) of the polyethylene (PE) unit. Downstream of this section where almost all the hydrocarbons have been purged from the product, there are trace amounts of hydrocarbons (ppmw range). The vents from this area are controlled with the RTO described in section 2.2.1, above.

2.2.2.1 High Pressure Vent Header

The HP Vent Header is designed to receive high load, short duration vent streams, also referred to as the “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, such as John Zink Company’s LRGO multi-point flare system, or one that is comparable. The multi-point ground flare system (EPN: 3UFLARE63) has a principle application to the petroleum refining and chemical processing industries due to its internal staging system that ensures short, smokeless flames maintained over the full operating range of the flare since burners are sequentially opened to maintain control.

The multi-point ground flare is expected to achieve a DRE well above the 98 to 99% DRE accepted for assist-type flares. Multi-point ground flare vendors have indicated that available ground flare technology will achieve 99.5% to 99.8%+ DRE for hydrocarbons. In fact, John Zink Company performed testing on the LRGO burner design and submitted the data and results to USEPA. The LRGO burner demonstrated 99.82% combustion efficiency when combusting a crude propylene stream. The composition of the HVHP vent stream that will be routed to the proposed multi-point ground flare system is comparable to the crude propylene used in the John Zink test since it contains highly combustible components such as hexene, hexane, isopentane, butene, butane, and ethylene, resulting in a typical heating value in excess of 800 BTU per standard cubic foot (Btu/scf) of off gas. Furthermore, after reviewing the proposed streams to be combusted in the multi-point ground flare as part of this project, John Zink has provided a performance guarantee stating that the hydrocarbon destruction efficiency will be 99.8% or greater when the multi-point ground flare is operated in the following range:

- Burner operating pressure > 4 psig and
- Flare gas net heating value > 800 BTU/SCF.

The operation of the multi-point ground flare system will be designed to meet the above requirements. Use of staging valves in this multi-header design allows the required minimum pressure of 4 psig to be maintained while the multi-point ground flare is operated. The HVHP vent stream that will be routed to the multi-point ground flare will consistently have a net heating value in excess of 800 Btu/scf. However, during the venting process, the stream may be diluted with nitrogen addition. In these instances, a computer control application will safely divert flow away from the multi-point ground flare and route it to the LP header. The two separate headers (HP and LP) will be connected through a spill-over line with a HP to LP valve controlled by a computer control application which will be used to direct the flow away from the HP header system. This may occur during defined periods of unit purging for shutdowns or startups when using nitrogen that dilutes the heat content (BTU/scf). This computer control application will also divert flow from the HP Vent Header to the LP Vent Header upon instances when the HVHP vent does not have adequate pressure above 4 psig. This computer control application will ensure the multi-point ground flare is operated only at times when the HP Vent Header meets the design conditions to achieve good combustion efficiency.

There may be a few instances where the waste gas will contain hydrogen. It is widely known that hydrogen contributes to good combustion more than its volumetric heating value of 274 Btu/scf would imply. Most notably, hydrogen contributes to good combustion as a result of a high flame speed. In an effort to address this consideration, an adjustment to the volumetric heating value of hydrogen is made when calculating the net heating value of waste gas streams routed to flares. This "net heating value of hydrogen as adjusted[1]" is 1,212 Btu/scf and more accurately reflects the realized contribution hydrogen makes to the good combustion of waste gas streams routed to flares.

The proposed multi-point ground flare system will use 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. This energy level is created by a high velocity discharge without requiring supplemental energy such as steam or forced air blowers. The philosophy of the control system provides that when gas (energy) flow is low, the number of burners is reduced in order that there is sufficient fuel supply to each burner to maintain the required energy level for clean burning.

The multi-point ground flare system will be provided with multiple headers, each header having multiple risers with burners. The burner is designed such that a number of small diameter ports eject high velocity gas, enhancing air entrainment and mixing for efficient and clean combustion. The aerodynamics of the burner provides air cooling and prevents flame recirculation, eliminating burner over-heating and internal coking. The staging control system, which can be either programmable logic controller (PLC) or distributed control system (DCS) based, will receive input from pressure transmitters and opens and closes staging valves according to waste gas pressure. Each stage is operated automatically with an actuated valve that opens or closes upon demand.

For the purposes of estimating GHG emissions, a flare combustion efficiency of 99.5% was applied since the pressure-assisted flare design has demonstrated higher efficiency when the total heating value of the flare stream is greater than 800 Btu/scf. The current multi-point ground flare design contains multiple runners and will contain pilots on each runner that will fire pipeline quality natural gas. A flow measurement system will be installed on the header to the multi-point ground flare. The pilots will be monitored for presence of flame. The emissions calculations for the multi-point ground flare i.e., 3UFLARE63 Intermittent Flaring and 3UFLARE63 Pilot Gas are contained in Appendix A.

2.2.2.2 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 can be achieved through the use of multiple flameless thermal oxidizers (FTOs) with an elevated flare serving as a secondary disposition.

The LP Vent Header will be equipped with on-line analyzers that provide real time measurement of the heat content and speciation of vent streams to the LP Vent Header. Since the LP Vent Header is the primary collection header for routine continuous operation vent streams that include potential infrequent periods of low heating value streams, the heat content analyzer provides the signal to allow for supplemental natural gas injection, if required, to maintain minimum heating value content in the vent gas.

2.2.2.2.1 Flameless Thermal Oxidizers

The primary control devices for the LP Vent Header are three FTOs (EPNs: 3UF61A/B/C), operated in parallel. Installing and operating three FTOs provides the capacity to reliably control the expected routine vent stream flow within the LP Vent Header for VOC emissions abatement. An automatic feed control system shall be provided to the FTOs to ensure optimal operation over a wide range of plant operation. Excess flow beyond the capacity of the FTOs will be routed to the elevated flare through a liquid seal drum. This control scheme ensures flow from the LP vent header will preferentially be routed to the FTOs.

Flameless Thermal Oxidizers (FTOs) are state of the art technology to control VOC emissions by achieving a very high destruction efficiency (rated at 99.99% VOC DRE) over a wide range of stream compositions. An air blower on the LP Vent Header ensures the flow is preferentially directed to this high efficiency combustion device that requires virtually no supplemental fuel addition for combustion during normal operation.

The proposed FTO system combusts natural gas during startup to achieve required operating temperature of the reaction bed. Once online, the FTO system utilizes natural gas only when the control application determines the minimum heating value is not contained within the incoming vent stream, therefore supplemental fuel is required to maintain proper control device temperature and destruction efficiency. The process conditions for the LP Vent Header are such that the routine vent streams routed to the FTOs contain sufficient heating value to maintain proper operating temperature, therefore supplemental fuel is not required for operation, other than at times of exceptionally low flow rates, and as such, the control application works to utilize supplemental fuel only when required due to the absence of heating value in the incoming feed stream. An air blower with flow controls will be utilized to provide optimization of the excess oxygen present and bed temperature profile in the reactor. However, it must be noted that higher excess oxygen at stack does not necessarily indicate lower energy efficiency (unlike boilers) of the equipment when the feed stream has more than adequate heat content and no supplemental fuel firing is required.

The patented technology of the proposed FTO system 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.

Unlike other packed-bed technologies, the reaction zone is stationary and continuous. This feature eliminates channeling or bypassing, allowing complete and efficient combustion while generating very low concentrations of NO_X and carbon monoxide (CO).

The nature of the reactor is to establish a reaction zone. The reaction zone is maintained at proper operating temperature. All the gases fed to the system must pass through this reaction zone, i.e., there are no bypasses or shortcuts. As such, all the gases along with combustion air pass slowly through this zone, fully oxidizing the organic materials. This assures that the FTO meets and exceeds 99.99% destruction efficiency.

High level of destruction is applicable to CO as well. A typical indicator for incomplete combustion is the presence of CO; however, with mixing not being a problem in the FTOs, the only time CO may be present is when there is insufficient air in the system. In this instance the stack oxygen measurement would adjust the system (increase air and/or reduce feed stream flow), therefore, temperature and oxygen concentration are the parameters that demonstrate good combustion and control equipment operation to its optimum performance.

2.2.2.2.2 Elevated Flare

The elevated flare (EPN: 3UFLARE62) provides the additional capability necessary to control all vent streams during normal operation of the LP Vent Header and is the control device of least priority within the vent collection system due to: (1) the comparatively lower destruction efficiency (DRE of 99% for hydrocarbons with three or less carbon atoms and 98% for hydrocarbons with more than three carbon atoms) and (2) this device 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.

The elevated flare (EPN: 3UFLARE62) will be designed to achieve a DRE of 99% for hydrocarbons with three or less carbon atoms and 98% for hydrocarbons with more than three carbon atoms with smokeless operation, however, for the purposes of estimating GHG emissions, an assumed flare combustion efficiency of 98% was applied since the total carbon content was the basis for emissions estimating, which does not segregate hydrocarbons.

The design of the elevated flare will be completed by an industry leader in flare technology and will incorporate industry-leading technology, including online flow and composition measurement and computer control. A flow measurement system will also be installed on the header to the elevated flare. The pilots will be fired by natural gas and will be monitored for presence of flame.

2.2.3 Boilers

Two new boilers each with a design firing capacity of 98 million British thermal units (MMBtu) per hour (hr) (HHV basis) will be used to produce steam for the proposed project (EPNs: RUPK31 and RUPK32).

2.2.4 Equipment Fugitive Components

The project proposes to install equipment fugitive components such as valves, flanges, pump seals, agitators, compressor seals, relief valves, open-ended lines, sampling connections, etc.

2.2.5 Analyzers

Emissions from the analyzer vents (EPN: PEXANALZ) are based on the estimated gas flow through each analyzer, vapor density, and vapor speciation. The proposed project design currently contains 35 analyzers distributed throughout the process equipment. Where applicable, analyzer vent streams are either returned to process or vented to the Vent Collection System. Other analyzer streams with very low hydrocarbon content will be vented directly to atmosphere. Remaining analyzers 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. The focus of TRACErase™ technology is the use of a catalytic combustion process to oxidize vented samples while maintaining an atmospheric pressure reference.

2.2.6 Hexene Storage Tank

One new floating roof tank will be constructed for storage of hexene. No increase in GHG emissions are being requested from the normal operation of the proposed tank.

2.2.7 Cooling Tower

A new cooling tower (EPN: RUCT01) 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 increase in GHG emissions are being requested from the proposed cooling tower.

2.2.8 Wastewater

A new wastewater stream was evaluated for GHG emissions. The oily water separator is an existing unit at the polyethylene base plant. A new waste water stream will be generated from the proposed project and will be routed to the existing waste water treatment system via the oily water separator. This new stream will not contain GHG constituents and will not be a source of GHG emissions for the project.

2.2.9 Miscellaneous Vents

The types of vent sources included in the proposed project are discussed below. No increase in GHG emissions are being requested from the proposed miscellaneous vents.

2.2.9.1 Additive System

To improve stability and weathering resistance of the polymer, a variety of bins, vessels and other equipment are used to store and mix additives into the material between the purgers and the extruders.

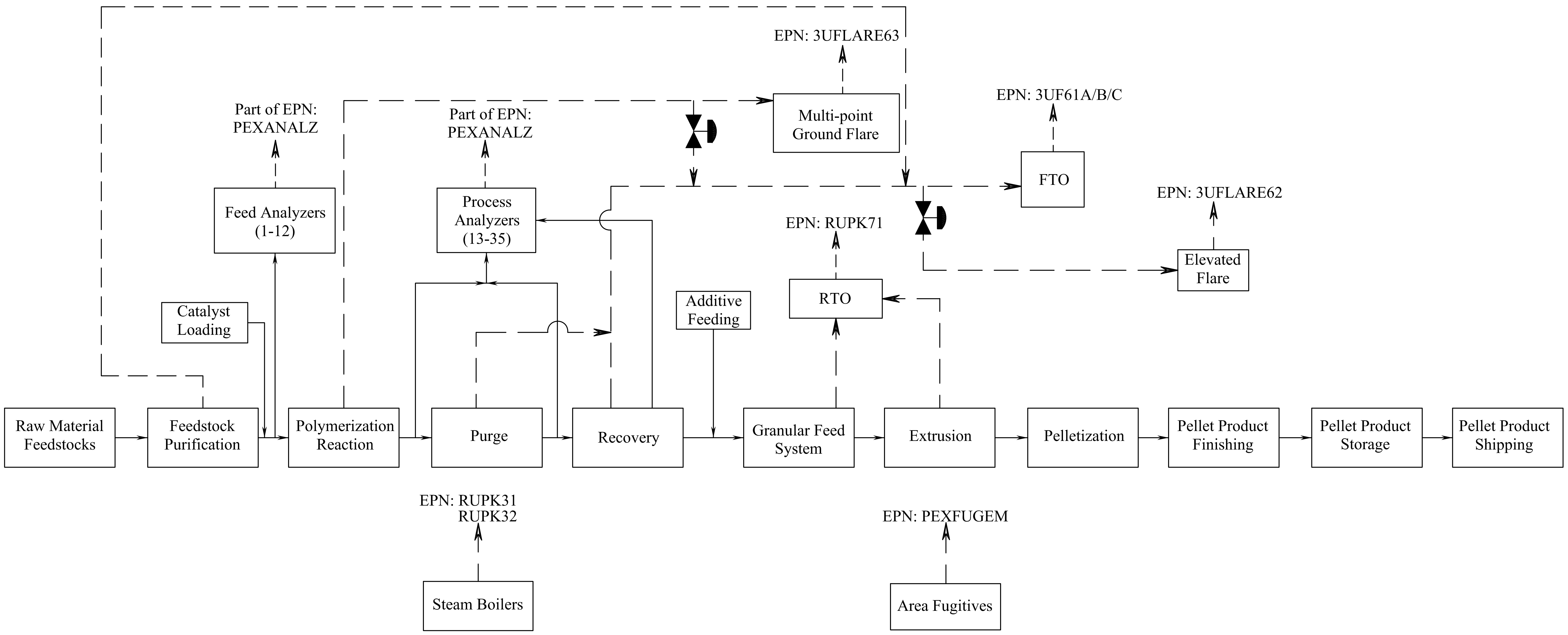
2.2.9.2 Catalyst Manufacturing

Proprietary catalyst material is conveyed from the existing polyethylene plant's manufacturing system to the reactors with a system of bins/vessels and filters.

2.2.9.3 Pellet Sources

Granular product polyethylene is extruded and pelletized. A variety of bins, vessels, and other equipment are used to convey, store, package, and load product for shipment off-site.

Figure 2-1. Simplified Block Flow Diagram for PE Process at MBPP



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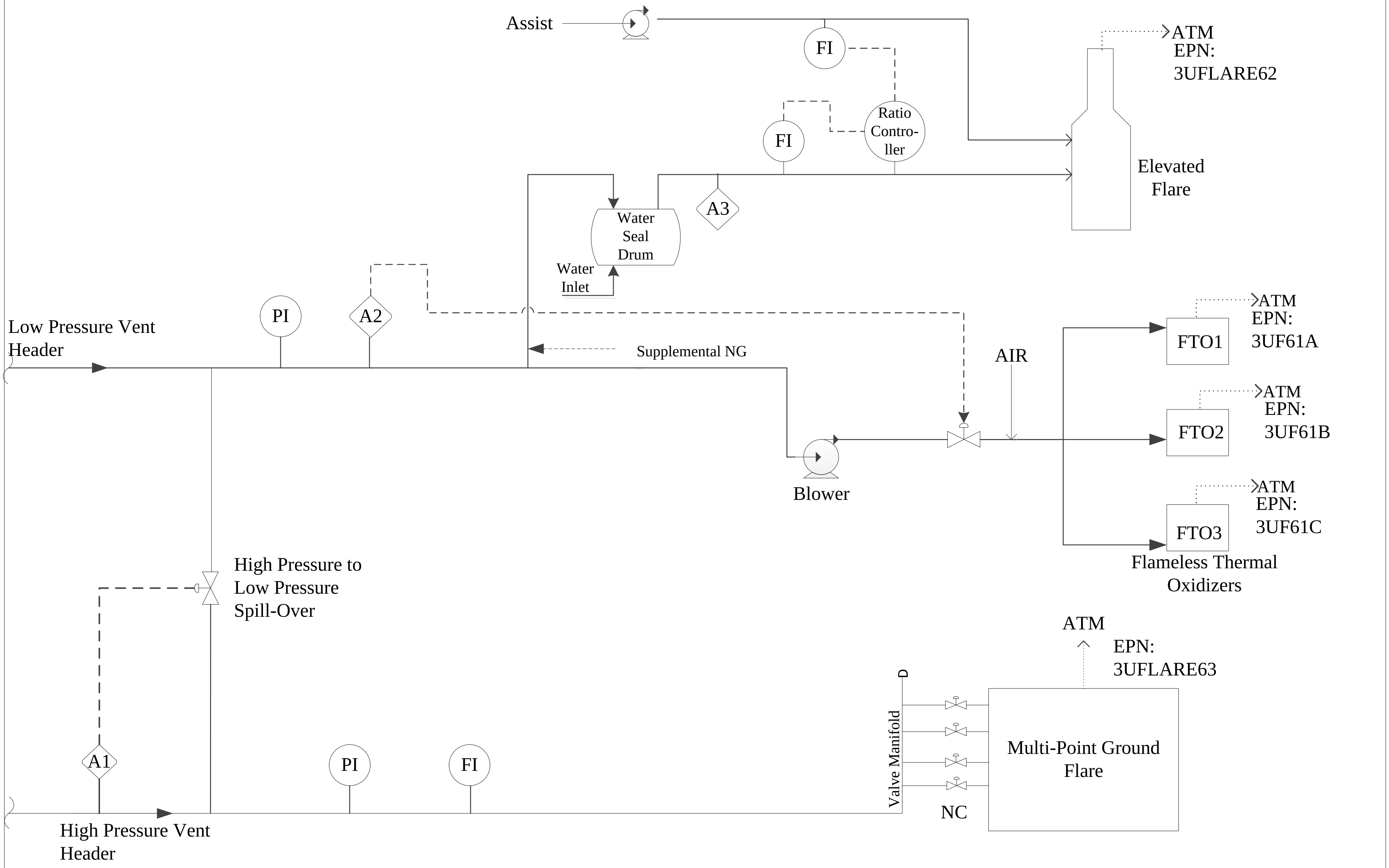
Drawing:	BFD.dwg	FIGURE 2-1
Revision #:	1	BFD for PE Process at MBPP
Date:	Revised March 2013	ExxonMobil Chemical Company
Project #:	55-6-12	Mont Belvieu PE Plant



A Heat content online analyzer or gas chromatograph
(to be determined)

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Vent Collection System
Flare Headers Simplified Schematic
ExxonMobil Mont Belvieu Plastics Plant

Revised: March 2013	Drawn: BC

SECTION 3

GHG EMISSION CALCULATION METHODOLOGY

This section describes the emission calculation methodologies used to calculate annual GHG emission rates for the emission sources associated with the proposed project. Detailed emission calculations are provided in Appendix A of this application. The calculation tables in this appendix are intended to be self-explanatory; therefore, the following discussion is limited to a general description of calculation methodologies and a summary of key assumptions and calculation basis data.

The pollutants associated with the project include CO_2, CH_4, and N_2O. The proposed project emission sources that contribute to these emissions include:

- Regenerative Thermal Oxidizer
- Vent Collection System
- Boilers
- Equipment Fugitive Components
- Analyzers
- Storage Tank
- Cooling Tower
- Wastewater
- Miscellaneous Vents

The specific calculation methodology for each emission source type is described in detail below. Note that all heating values used in each equation for the following sections are the higher heating values (HHV). Table 3-2 at the end of this section contains an emission point summary for these sources.

3.1 CO_2e Emissions

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential (GWP). The GWP values in Table A-1 of the Green House Gas Mandatory Reporting Rule (GHG MRR) (40 CFR Part 98, Subpart A, Table A-1) were used to calculate CO_2e emissions from estimated emissions of CO_2, CH_4, and N_2O by multiplying the individual GHG pollutant rates by their applicable GWP provided in Table 3-1 below.

Table 3-1 GWP Table

GHG POLLUTANT	GWP (ton pollutant / ton CO_2e)
CO_2	1
CH_4	21
N_2O	310

3.2 Regenerative Thermal Oxidizer

Supplemental fuel is added to the stream during start-up to ensure sufficient heating value. Annual emissions are based on 97% on-line reliability. When the RTO is off-line, the vents will emit to atmosphere without GHG emissions. The RTO as a VOC control device achieves better than federal BACT emission reductions for VOC and is utilized due to the dilute nature of the vent stream. The emissions for the RTO are based on the anticipated gas flow, higher heating value, and carbon content of the fuel streams to the unit according to 40 CFR 98 Subchapter C using Tier 3 calculation methodology. CH_4 and N_2O emissions from the RTO were calculated based on the emission factor of 1×10^{-3} kg-CH_4 / MMBtu and 1×10^{-4} kg-N_2O / MMBtu (40 CFR 98 Subpart C Table C-2), respectively. The CO_2e emissions are calculated as described in Section 3.1.

Detailed calculations for this determination are provided in Appendix A to this application. The proposed allowable emissions of CO_2, CH_4, and N_2O expressed as CO_2e for the RTO associated with the proposed project are presented in Table 3-2 at the end of this section.

3.3 Vent Collection System

The emissions for the Vent Collection System are based on the anticipated gas flow, higher heating value, and carbon content of the vent streams. FTO CO_2 emissions were calculated with Equation C-5 from 40 CFR 98 Subchapter C using Tier 3 calculation methodology. CH_4 and N_2O emissions from the FTOs were calculated based on the emission factor of 1×10^{-3} kg-CH_4 / MMBtu and 1×10^{-4} kg-N_2O / MMBtu (40 CFR 98 Subpart C Table C-2), respectively. Note that it is not feasible to adhere to a numerical emission limit for burner firing during FTO startup, because it is an intermittent emission source. GHG emissions generated during this intermittent operation are accounted for in the total FTO emissions.

Elevated flare CO_2 emissions were estimated according to Equation Y-1a from the Federal GHG MRR 40 CFR 98 Subpart Y. Elevated flare CH_4 and N_2O were calculated according to Equations Y-4 and Y-5, respectively, from the Federal GHG MRR 40 CFR 98 Subpart Y.

The emissions for the multi-point ground flare are estimated from representative off gas mass flow, stream speciation, and higher heating value of the vent streams to the HP Vent Header. CO_2 emissions from the multi-point ground flare were estimated according to Equation Y-1a from the Federal GHG MRR 40 CFR 98 Subpart Y. CH_4 and N_2O emissions from the multi-point ground flare were calculated according to Equations Y-4 and Y-5, respectively, from the Federal GHG MRR 40 CFR 98 Subpart Y.

The representative case for annual emissions was derived using engineering analysis based on the annual vent gas composition. The flows expected to be routed to the multi-point ground flare are considered high volume, high pressure (HVHP) flows. Although the HVHP flows differ for the typical operating scenarios anticipated for the multi-point ground flare, the flows during each scenario do not vary excessively. HVHP vent streams anticipated to be controlled by the multi-point ground flare can be categorized as ‘start-ups’ (after shutdown, cleaning, and/or maintenance) and ‘shutdowns’ (operational transitions, catalyst change outs, grade changes, process safety releases, etc.).

The GWP values in Table A-1 of the GHG MRR (40 CFR Part 98, Subpart A) were used to calculate CO_2e emissions from estimated emissions of CO_2, CH_4, and N_2O by multiplying the individual GHG pollutant rates by their applicable GWP.

Detailed calculations for this determination are provided in Appendix A. The proposed allowable emissions of CO_2, CH_4, and N_2O expressed as CO_2e for the Vent Collection System associated with the proposed project are presented in Table 3-2 at the end of this section.

3.4 Boilers

The CO_2 emissions for the boilers are based on the anticipated gas flow, higher heating value, and carbon content of the fuel streams to the unit according to 40 CFR 98 Subchapter C using Tier 3 calculation methodology. CH_4 and N_2O emissions from the boilers were calculated based on the emission factor of 1×10^{-3} kg-CH_4 / MMBtu and 1×10^{-4} kg-N_2O / MMBtu (40 CFR 98 Subpart C Table C-2), respectively. The CO_2e emissions are calculated as described in Section 3.1.

Detailed calculations for this determination are provided in Appendix A to this application. The proposed allowable emissions of CO_2, CH_4, and N_2O expressed as CO_2e for the boilers associated with the proposed project are presented in Table 3-2 at the end of this section.

3.5 Equipment Fugitive Emissions

Fugitive emission rates of VOC from the piping components and ancillary equipment may be estimated using the methods outlined in the TCEQ’s *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.* However, the fugitive emissions are estimates only, since they are based on factors derived for a statistical sample, and are not specific to any single piping component or specifically for natural gas service.

To estimate fugitive emissions, each fugitive component was classified first by equipment type (valve, pump, relief valve, etc.) and then by material type (gas/vapor, light liquid, heavy liquid). An estimated, uncontrolled emission rate was obtained by multiplying the number of estimated fugitive components of a particular equipment/material type by the appropriate emission factor per the TCEQ guidance document. To obtain estimated, controlled fugitive emission rates, the estimated, uncontrolled emission rates were multiplied by a control factor, which was determined by the LDAR program employed for that source type. For the estimated CH_4 emissions from added fugitive components, emissions were calculated using the appropriate SOCMI emissions factors and based on the representative stream speciation.

The estimated CH_4 emissions, which are also expressed as CO_2e according to the methodology described in Section 3.1, for the new fugitive components from the proposed project are summarized in Appendix A of this application. However, the fugitive emission limits are not included Table 3-2 Emission Point Summary since fugitive emissions are estimates only as discussed above.

3.6 Analyzers

CO_2 emissions from the analyzer vents are based on the estimated gas flow through each analyzer, vapor density, vapor speciation, and a 98% destruction efficiency. The CO_2e emissions are calculated as described in Section 3.1. The destruction efficiency applies to the destruction efficiency of the analyzer devices equipped with TRACErase™ technology, as previously described in Section 2.2.5.

Detailed calculations for this determination are provided in Appendix A to this application. The proposed allowable emissions of CO_2, CH_4, and N_2O expressed as CO_2e for the analyzers associated with the proposed project are presented in Table 3-2 at the end of this section, and assume that all 35 analyzers contain TRACErase™ technology.

3.7 Hexene Storage Tank

The proposed new Hexene storage tank is not a source of GHG emissions. Detailed calculations for this determination are provided in Appendix A to this application.

3.8 Cooling Tower

The proposed new cooling tower is not a source of GHG emissions. Detailed calculations for this determination are provided in Appendix A to this application.

3.9 Wastewater

The proposed new wastewater stream is not a source of GHG emissions. Detailed calculations for this determination are provided in Appendix A to this application.

3.10 Miscellaneous Vents

The proposed new miscellaneous vents are not a source of GHG emissions. Detailed calculations for this determination are provided in Appendix A to this application.

Table 3-2
Emission Point Summary

Date:	Revised March 2013	Permit No.:	TBD	Site Name:	Mont Belvieu Plastics Plant
Company Name:	ExxonMobil Chemical Company			Project:	Polyethylene Unit

Air Contaminant Data					
Emission Point			**Component or Air Contaminant Name**	**GHG Emission Rate (tons/yr)**	**CO_2e Emission Rate (ton/yr)** [A]
EPN	**FIN**	**Name**			
RUPK71	RUPK71	Regenerative Thermal Oxidizer	CO_2	2,221	2,221
			N_2O	1	310
			CH_4	1	21
PEXVCS 3UF61A/B/C 3UFLARE62 3UFLARE63	3UF61A/B/C 3UFLARE62 3UFLARE63	Vent Collection System	CO_2	97,582	97,582
			N_2O	5	1,550
			CH_4	11	231
RUPK31 RUPK32	RUPK31 RUPK32	Boiler 31 Boiler 32	CO_2	30,512	30,512
			N_2O	1	310
			CH_4	2	42
PEXFUGEM	PEXFUGEM	Fugitives	CO_2	(B)	(B)
			CH_4	(B)	(B)
PEXANALZ	PEXANALZ	Analyzers	CO_2	28	28
Proposed Project Compliance Total			CO_2	130,343	130,343
			N_2O	7	2,170
			CH_4	14	294
			Total	130,364	132,807

[A] Air contaminant emission rates are contributions to the project CO_2e compliance total.

[B] Air contaminant emission rates are estimates only for fugitive sources.

EPN = Emission Point Number
FIN = Facility Identification Number

SECTION 4
GHG BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

The increase in GHG emissions associated with the proposed project is above the PSD threshold for GHG. As such, any new or modified emissions unit with a net increase in CO_2, CH_4, and N_2O emissions is subject to BACT review. The sources subject to BACT review in the proposed project are the, new RTO, new Vent Collection System, new boilers, new fugitive components, and analyzers.

CO_2 emissions account for approximately 99 percent of the total CO_2e emissions for the proposed project. As a result, the GHG BACT analyses are focused on CO_2.

4.1 BACT Analysis Methodology

BACT is defined in 40 CFR §52.21(b) (12) as "...an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from a source which on a case-by-case basis is determined to be achievable taking into account energy, environmental and economic impacts and other costs". In the USEPA guidance documents titled the *1990 Draft New Source Review Workshop Manual* and the *PSD and Title V Permitting Guidance for Greenhouse Gases*, USEPA recommends the use of the Agency's five-step "top-down" BACT process to determine BACT for PSD permit applications in general, and GHG permit applications specifically. In brief, the top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT. The five basic steps of a top-down BACT analysis are listed below:

Step 1: Identify potential control technologies.
Step 2: Eliminate technically infeasible options.
Step 3: Rank remaining control technologies.
Step 4: Evaluate the most effective controls and document results.
Step 5: Select the BACT.

The first step is to identify potentially "available" control options for each emission unit subject to BACT review, for each pollutant under review. Available options should consist of a comprehensive list of those technologies with a potentially practical application to the emission unit in question. For this analysis, the following sources are typically consulted when identifying potential technologies:

- USEPA's New Source Review Website,
- USEPA's RACT/BACT/LAER Clearinghouse (RBLC) Database,
- Engineering experience with similar control applications,
- Various state air quality regulations and websites, and
- Guidance Documents and Reports including:
    - "Available And Emerging Technologies For Reducing Greenhouse Gas Emissions From The Petroleum Refining Industry" published by USEPA Office of Air and Radiation; and
    - "Report of the Interagency Task Force on Carbon Capture and Storage" obtained from http://www.epa.gov/climatechange/policy/ccs_task_force.html.

The results of a RBLC Database search are included in Appendix B to this application. Applicable technologies are included in this BACT analysis.

After identifying potential technologies, the second step is to eliminate technically infeasible options from further consideration. To be considered feasible, a technology must be both available and applicable. A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available".

The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern.

The fourth step entails an evaluation of energy, environmental, and economic impacts for determining a final level of control. The evaluation begins with the most stringent control option and continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts.

The fifth and final step is to select as BACT the most effective of the remaining technologies under consideration for each pollutant of concern.

4.2 Regenerative Thermal Oxidizer

The RTO is a control device that will be installed to meet BACT for another PSD pollutant - residual VOC emissions from the powder hopper bag filter, conveying air vents and extruder feed vents. Control devices installed to meet BACT for an emission source are typically not subject to an additional BACT evaluation for the control device itself. Rather the ancillary emissions generated by the control device are addressed in the environmental impacts evaluation for the source being controlled (in this case the powder hopper bag filter). Even though it is not appropriate to conduct a BACT evaluation on equipment installed to meet BACT, a redundant evaluation is included in the interest of expediting GHG permit issuance.

The RTO will emit three GHG: CH_4, CO_2, and N_2O. CO_2 will be emitted from the RTO because it is a combustion product of any carbon-containing gas. CH_4 will be emitted as a result of any incomplete combustion. N_2O will be emitted from in trace quantities due to partial oxidation of nitrogen in the air which is used as the oxygen source for the combustion process. CO_2 emissions account for approximately 99% of the total CO_2e emissions. As a result, the GHG BACT analysis is focused on CO_2.

4.2.1 Step 1 – Identification of Potential Control Technologies

The following technologies were identified as potential control options for the RTO based on available information and data sources:

- Use of low carbon assist gas;
- Use of good operating and maintenance practices;
- Energy efficient design; and
- Carbon Capture and Sequestration (CCS)

4.2.1.1 Low Carbon Assist Gas

Fuels containing lower concentrations of carbon generate less CO_2 emissions than higher carbon fuels. Natural gas is among the lowest-carbon fuels commercially available. As contained in 40 CFR 98, Subpart C, Table C-1, there are 56 other fuels with larger CO_2 emission factors than the factors for natural gas.

4.2.1.2 Good Operating and Maintenance Practices

Good operating and maintenance practices for the RTO are common techniques and are similar to those outlined for the boiler in Section 4.4.1.2. The burners installed for the RTO operate to provide supplemental heat necessary for the RTO to maintain operating temperature. Although the RTO efficiently recovers heat required for oxidation, the heat content of the incoming feed is not sufficient to provide the heat required to maintain required temperature. The manufacturer uses a burner design that provides complete combustion of the natural gas fuel, in order to minimize assist gas consumption. This is standard industry practice and the highest efficiency level that can be achieved for a burner.

The burners will be visually inspected prior to startup (and during planned boiler maintenance shutdowns) to ensure proper performance per current practices at MBPP. On-site personnel will be alerted to problems through a low temperature alarm if the RTO reaches minimum operating temperature that was demonstrated during the performance test to establish DRE. Upon notification of an alarm, Operations will employ troubleshooting practices to identify and resolve the issue with appropriate support as needed.

The RTO will ensure operation at adequately elevated temperature so that the DRE demonstrated through performance testing is achieved. As previously discussed, the RTO is utilized for vents containing residual levels of hydrocarbons from the powder hopper bag filter, conveying air vents and extruder feed vents due to the dilute VOC content, i.e. extremely low heat content, therefore supplemental fuel is utilized to achieve proper temperature. It is temperature and not excess oxygen that indicates proper operation, therefore temperature is the operating parameter that is monitored and integrated into the control application for the RTO since the largest cost of operating a RTO is the supplemental fuel.

The fuel burned in the RTO burner for oxidation of vent gas is pipeline natural gas, and the flow rate is monitored. The feed stream to RTO is a very low concentration stream and is monitored for flow rate.

Temperature is the key operating parameter that is monitored to indicate the performance of the RTO. A minimum operating temperature will be specified by vendor and/or by demonstration. The temperature will be measured within the reactor and recorded. A computer control application will manage the operation of the RTO to ensure it operates within its performance targets. The control application optimizes the amount of supplemental fuel per the reaction zone temperature. It is not economical or environmentally beneficial to operate the RTO at a higher temperature than required; therefore the control application optimizes the amount of supplemental fuel per the reaction zone temperature and maintains the temperature at the lowest temperature possible that ensures proper operation. In other words, the lower the temperature, the lower the supplemental fuel requirement and this is principle is that makes the RTO GHG efficient.

Refer to Appendix C for a summary of the proposed work practice standards, operating limits, and/or monitoring to ensure good combustion efficiency for the RTO.

4.2.1.3 Energy Efficient Design

Energy efficiency is inherent in the operation of a RTO. Specific technologies include the following:

- 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.
- Improved Process Control – installation of oxygen monitors and intake air flow monitors to optimize the fuel/air mixture and limit excess air.

RTO is employed to ensure an absolute reduction in VOC released is achieved even in a low hydrocarbon content polyethylene unit product stream (~ 130 ppmv in residual hydrocarbon) as the resin is conveyed to the silos, after completing hydrocarbon purging in the process. The RTO was chosen to control this very lean hydrocarbon stream efficiently (achieve ~ 2 ppmv total hydrocarbon level in the exhaust from RTO). A regenerative thermal process is utilized whereby a cyclic heat recovery step is integrated into heating incoming feed gas with excess air to ensure complete and high efficiency combustion of the low hydrocarbon stream. This stream, in a typical Polymers plant would be vented to atmosphere without treatment. Thus, deploying an RTO exceeds federal-level BACT for control of VOC.

The thermodynamic principle driving operation of the RTO is efficient heat transfer. As described in EPA's Air Pollution Control Technology Fact Sheet[1]:

> RTOs use a high-density media such as a ceramic-packed bed still hot from a previous cycle to preheat an incoming VOC-laden waste gas stream. The preheated, partially oxidized gases then enter a combustion chamber where they are heated by auxiliary fuel (natural gas) combustion to a final oxidation temperature typically between 1,400 and 1,500 °F, and maintained at this temperature to achieve maximum destruction efficiency. The purified, hot gases exit this chamber and are directed to one or more different ceramic-packed beds cooled by an earlier cycle. Heat from the purified gases is absorbed by these beds before the gases are exhausted to the atmosphere. The reheated packed bed then begins a new cycle by heating a new incoming waste gas stream.

The RTO designed for the proposed project includes the technologies described above by EPA:

> The heat exchanger bed is comprised of separate sections, where alternately one part functions as cooling stage and the other as heating stage. The exhaust air passes vertically upward through the heat exchanger mass taking on the heat and raising the air temperature close to the oxidation of the pollutants at approximately 800 °C (1,472 °F). The hot purified gases pass downward through the other part of the heat exchanger mass transferring its energy back to the exchanger. This cools down the purified gases.

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[1] *EPA website: http://www.epa.gov/ttn/catc/dir1/fregen.pdf accessed on October 24, 2012.*

Furthermore, the proposed RTO will be designed with a sophisticated air distribution system that will control the alternating airflow through the individual heat exchanger sections. This replaces complicated damper mechanisms and eliminates difficulties with conventional design duct dampers. The benefits of the proposed RTO over other conventional RTOs include constant air distribution instead of damper mechanisms, eliminates the need for compressed air, low wear and tear, and no pressure variations caused by switching operations. Although it cannot be quantified, a less complicated design with less moving parts and improved automation provides for a higher reliability and consistent operation of the RTO which results in improved energy efficiency. Also of note is that the alternative to this technology is incineration in order to achieve the high destruction efficiency for the low hydrocarbon content stream. Incineration is far more energy intensive than RTO, thereby generating more GHG emissions.

As described above, the proposed RTO will be designed with a sophisticated air distribution system that uses a rotating distributor to control the alternating airflow through the individual heat exchanger sections. A computer control application manages the rotating distributor to ensure consistent operation. The operating parameter that will be monitored to ensure optimal heat transfer is temperature at the stack. Since supplemental fuel is required to maintain temperature at the reaction zone, the RTO will be managed such that temperature is maintained near its minimum during operation in order to minimize the amount of supplemental fuel required. In addition, exit temperature at stack shall be monitored that shows the extent of heat recovery from exhaust gas. This optimization strategy will be integrated into the control application since supplemental fuel has an economic penalty associated with it.

Refer to Appendix C for a summary of the proposed work practice standards, operating limits, and/or monitoring to ensure high energy efficiency for the RTO.

4.2.1.4 Carbon Capture and Sequestration (CCS)

Refer to Section 4.3.2.5 for a detailed description of these practices.

4.2.2 Step 2 - Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible unless it is both available and applicable.

4.2.2.1 Low Carbon Assist Gas

Use of natural gas as a low carbon assist gas is technically feasible.

4.2.2.2 Good Operating and Maintenance Practice

Use of good operating and maintenance practice is considered technically feasible.

4.2.2.3 Energy Efficiency

Use of the energy efficiency measures described in Section 4.3.1.4 is considered technically feasible.

4.2.2.4 Carbon Capture and Storage

CCS is considered technically, environmentally, and economically infeasible for sources with much larger emissions (two orders of magnitude) than the RTO; refer to section 4.3.2.5 for detailed discussion.

4.2.3 Step 3 - Rank Remaining Control Technologies

The following technologies and control efficiencies were identified as technically feasible for CO_2 control options for the RTO based on available information and data sources:

- Use of low carbon assist gas;
- Use of good operating and maintenance practices; and
- Energy efficient design.

4.2.4 Step 4 - Evaluate the Most Effective Controls and Document Results

Although all fossil fuels contain carbon, the natural gas fired in the proposed RTO is a low carbon assist gas. In the combustion of a fossil fuel, the fuel carbon is oxidized into CO and CO_2. Full oxidation of fuel carbon to CO_2 is desirable because CO has long been a regulated pollutant with established adverse environmental impacts and because full combustion releases more useful energy within the process. In addition, emitted CO gradually oxidizes to CO_2 in the atmosphere.

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.

4.2.5 Step 5 - Selection of BACT

As a result of this analysis, the use of low carbon assist gas, good operating and maintenance practices, and energy efficient design is selected as BACT for the proposed RTO. This finding is consistent with the proposed rule *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric*

Generating Units, which states[2]:

> Second, all newly constructed sources have options in selecting their design (although it is true that natural gas-fired plants are inherently lower emitting with regard to CO_2 than coal-fired plants). As a result, prospective owners and operators of new sources could readily comply with the proposed emission standards by choosing to construct a NGCC[3] unit.

The proposed emission standard referenced above is:

> The proposed requirements, which are strictly limited to new sources, would require new fossil fuel-fired EGU's greater than 25 megawatt electric (MWe) to meet an output-based standard of 1,000 lb of CO_2 per megawatt-hour (MWh), based on the performance of widely used natural gas combined cycle (NGCC) technology[4].

This proposed rule is currently the only NSPS for GHG, and although it is applicable to electric generating units rather than RTOs, it based the emission limitation on sources firing natural gas, without further controls for GHG. Therefore, the controls selected in the top-down BACT analysis for the proposed RTO, specifically firing of natural gas as assist gas, meet or exceed the controls required in the proposed NSPS for Greenhouse Gases.

Appendix C of this application contains a summary of work practice standards, operational requirements, and/or monitoring for the proposed RTO.

4.3 Vent Collection System

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 achieving better than BACT-levels (voluntarily achieving LAER-levels) of control in an ozone non-attainment area. Due to the integration of the computer control applications that manage the three control devices and operation of the Vent Collection System, this BACT analysis focuses on the combined Vent Collection System as a collective emission source resulting from the control of another PSD pollutant (VOC). Control devices installed to meet BACT for an emission source are typically not subject to an additional BACT evaluation for the control device itself. Rather the ancillary emissions generated by the control device are addressed in the environmental impacts evaluation for the source being controlled (in this case the Reactors, Purger, etc.). Even though it is not appropriate to conduct a BACT evaluation on equipment installed to meet BACT, a redundant evaluation is included in the interest of expediting GHG permit issuance.

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[2] 77 *FedReg 22410*, April 13, 2012.
[3] Natural Gas Combined Cycle
[4] 77 *FedReg 22392*, April 13, 2012.

Additionally, since CO_2 accounts for over 99% of the total CO_2e emissions from these emission sources, this GHG BACT analysis is focused on controlling CO_2 emissions.

4.3.1 Step 1 – Identification of Potential Control Technologies

The following technologies were identified as potential control options for the Vent Collection System based on review of available information and data sources:

- Use of low carbon assist gas;
- Use of good operating and maintenance practices;
- Staged operation;
- Energy efficient design;
- Vent gas recovery (VGR); and
- Carbon Capture and Sequestration (CCS).

4.3.1.1 Low Carbon Assist Gas

A discussed in section 4.2.1.1, the use of natural gas as assist gas is the lowest-carbon fuel available for the proposed project.

4.3.1.2 Good Operating and Maintenance Practices

- Appropriate maintenance of equipment (analyzers, flow measurement systems),
- Operation at the designed temperature and oxygen concentration in the FTOs,
- Operation based on recommended design velocity and heating value for the elevated flare, and
- Operation based on recommended design pressure and heating value for the multi-point ground flare.

4.3.1.3 Staged Operation

The proposed project will install a Vent Collection System with staged operation. By segregating these low and high pressure streams into different control device dispositions, the proposed project will optimize the amount of assist gas and air to hydrocarbon ratio required for good combustion. This will minimize the amount of CO_2 generated by destruction of vent streams.

4.3.1.4 Energy Efficient Design

The FTOs do not require supplemental fuel or heat to maintain optimum operation, unless the FTOs are operated at high turndown, i.e., essentially no flow is routed to the LP Vent Header, or the incoming feed stream does not have adequate heat content. The FTOs are designed to maintain operating temperature through control applications that balance the excess oxygen levels based on feed forward control of the incoming feed stream. This feed stream, consisting of low volume, low pressure vents routed to the LP vent header, contains sufficient heat value such that supplemental fuel is not expected to be required during normal operation. FTOs are able to “burn” waste gasses at lower heating values than would be required with direct fire burners. The device uses a thermal ceramic bed to allow oxidation to occur at much lower heat contents reducing supplemental fuel requirements. The vent stream therefore ensures the reactor is energy efficient by providing sufficient heat to maintain proper operating temperature. Additionally, the use of variable flow air blower with a computer control application to control the excess oxygen based on the incoming feed to the FTOs improves energy efficiency.

4.3.1.5 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.

4.3.1.6 Carbon Capture and Sequestration (CCS)

Refer to Section 4.3.2.5 for a detailed description of these practices

4.3.2 Step 2 - Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible unless it is both available and applicable.

4.3.2.1 Low Carbon Assist Gas

Use of a low carbon fuel is technically feasible. Pipeline quality natural gas is the lowest carbon fuel commercially available at MBPP. Natural gas will be selected by the proposed project since it is the only fuel commercially available at MBPP.

4.3.2.2 Good Operating and Maintenance Practices

Use of good operating and maintenance practices is considered technically feasible. The use of good operating and maintenance practices results in longer life of the equipment and more efficient operation. Therefore, such practices indirectly reduce GHG emissions by supporting operation as designed by the manufacturer. Use of good operating and maintenance practices as described in Section 4.3.1.2 is technically feasible and will be incorporated into the proposed project.

4.3.2.3 Staged Operation

The staged operation is integral to the design of the Vent Collection System, with three separate control devices for the various vent streams.

4.3.2.4 Energy Efficiency

Use of the energy efficiency design described in Section 4.3.1.4 is considered technically feasible and will be incorporated into the proposed project.

4.3.2.5 Vent Gas Recovery (VGR);

A compression system was specified with a total capacity to recover up to 1,800 pounds per hour of vent 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. Since vent gas recovery is technically feasible, an economic analysis was performed to evaluate the economic feasibility of this control technology. Table 4-1 summarizes the economic analysis of vent gas recovery for the proposed project, which is estimated to avoid 11,541 tons of CO_2e per year. As shown in the table, vent gas recovery is estimated at a cost of $123.2 per ton of CO_2e avoided, which is an excessive cost to mitigate GHG emissions and renders flare gas recovery an economically infeasible control technology. Therefore, it is eliminated from consideration as a control technology for flare GHG emissions.

Table 4-1 Economic Analysis for Vent Gas Recovery

Item	Units	Value[5]	Comments
Vent Gas Recovery System Cost			
Capital Cost of VGR	\$ (millions)	7.0	Site-specific design
Amortized Capital Cost	\$ (millions)	1.4[6]	See Footnote
Operating and Maintenance Expenses	\$ (millions)	0.05	Site-specific design incorporating natural gas consumption reduction
Total Annual VGR Cost	**\$ (millions) / yr**	**1.4**	
Vent Gas Recovered			
Total Vent Gas Recovered	MMscf/yr	311.4	Based on estimate of 1,000 lb/hr of NG reduction
	MMBtu/yr	196,812	Higher heating value of 639 Btu/scf
Economics of Avoided CO_2e			
Annual Emissions from FTO Control of Vent Gas	tons CO_2e / yr	14,607	Oxidation emissions from unrecovered vent gas
Annual Emissions from Recovered Vent Gas to Boilers	tons CO_2e / yr	14,607	Firing recovered vent gas at the boilers
Annual Emissions from Natural Gas to Boilers	tons CO_2e / yr	11,541	Firing natural gas at the boilers
Tons of CO_2e Avoided	**tpy**	**11,541**[7]	
Cost per ton of CO_2e Avoided	**\$ / ton CO_2e**	**123.2**	

4.3.2.6 Carbon Capture and Sequestration

ExxonMobil is a leader in the research, development and application of CCS and related technologies, with over 30 years of extensive experience in technology that could be transferable to CCS operations. ExxonMobil recognizes CCS is a promising technology for mitigating GHG emissions, but through our experience we also recognize that significant challenges must be overcome for wide-spread deployment across various industries. Challenges include high capture cost; first-of-a-kind (FOAK) technology deployments in new industrial sectors with unknown technology and process safety risks; and insufficient regulatory frameworks, including management of long-term responsibility, lack of transport infrastructure networks, long-term storage

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[5] *All monetary estimations have been calculated in 2016 dollars.*

[6] *A capital charge rate of 19% was assumed with an expected equipment life of 20 years.*

[7] *Tons of CO_2e avoided = Annual Emissions from FTO control of Vent Gas + Annual Emissions from Boiler Firing Natural Gas - Annual Emissions from Boiler Firing Recovered Vent Gas = 14,607 tpy + 11,541 tpy – 14,607 tpy = 11,541 tpy*

integrity confidence, and uncertain public acceptance of CCS projects. A number of large scale integrated projects have been cancelled over the past several years, both in the US and other parts of the world, generally citing all or a combination of the aforementioned challenges as barriers to the CCS project.

CCS has been evaluated for the proposed project based on technological, environmental, and economic feasibility. In the guidance documents for GHG permitting, USEPA states[8]:

> For the purpose of the BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of the top-down BACT Analysis for GHGs.

ExxonMobil does not consider CCS as "available" for any application other than processing produced natural gas. There are no global examples where capture of CO_2 from a low pressure, low CO_2 concentration flue gas has been demonstrated at a scale and level of reliability necessary for application in a compliance-based scenario. The proposed project, with its numerous emission points and low CO_2 concentration, does not meet the criteria established in the above paragraph, nor does it meet any reasonable definition of BACT because CCS has not been demonstrated as an "available" and "applicable" technology for thermal oxidizers or a polyethylene unit or any similar applications. The proposed project is not analogous to a fossil fuel-fired power plant due to exhaust gas flow rate differences occurring from firing a power plant's turbine compared to controlling VOC emissions in the proposed Vent Collection System. A fossil fuel-fired power plant stack volumetric flow rate is several orders of magnitude greater than the Vent Collection System represented in this permit application.

Nor does the proposed project compare to an industrial facility with high-purity CO_2 streams since the proposed project will construct several separate sources that will emit very low-purity CO_2 streams. The industrial facilities cited in the above USEPA example are similar to each other in that each has a limited number of stacks and the purity of the CO_2 for most is in the range of 65% (versus ~ 8 % for a boiler). A polyethylene unit is not a comparable process to hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron

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and steel manufacturing by any measure, especially regarding the purity of the CO_2 in the stack, which is less than 8%. USEPA specifically cited CCS technology as “available” for the power plant and high-purity industrial facility streams simply because these are the applications that are either most impactful to reduce total US GHG emissions (in the case of fossil fuel-fired power plants) or may be best suited for CCS technology applications (in the case of hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing) when only CO_2 source gas characteristics are evaluated. CCS is not applicable to polyethylene units because of the low purity CO_2-containing streams emitted from multiple stacks across the facility.

While specific component CCS technologies exist and have been in use for decades, integrated CCS facilities at the necessary scale for a polyethylene unit have not been demonstrated and do not currently exist at any scale. The following subsections describe the specific technologies comprising CCS and detail the specific barriers each pose to the proposed project and highlight why CCS is not an available or applicable technology for the proposed project.

Capture

While several technologies for the post-combustion capture of low-pressure, low-concentration CO_2 may be in development, none have been demonstrated at the scale of the proposed project nor for sources at natural gas fired facilities. Carbon capture for the proposed project would require FOAK technology application that is further complicated by the numerous emission points within the polyethylene unit. Any CCS technology will result in additional equipment, operating complexity, and increased energy consumption to operate the add-on equipment. Additional equipment would increase the energy and fuel demand and significantly increase the size of the power generation system, which would lead to more air pollution and wastewater generation at the site.

Further, as stated in the August 2010 Report of the Interagency Task Force on Carbon Capture and Storage[9]:

> Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG

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[9] *President Obama’s Interagency Task Force on Carbon Capture and Storage, Report of the Interagency Task Force on Carbon Capture and Storage, August 2010, p. 50.*

> emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment.

Recovery and purification of CO_2 from the FTOs' and boilers' flue gas would require significant additional processing to achieve the necessary CO_2 concentration for effective storage. The proposed project's exhaust streams are not high-purity streams, as recommended in USEPA's guidance. Instead, the exhausts contain less than eight (8) vol% CO_2 in the stack gas on an average annual basis, and would have to be purified and dried to a purity of over 98%. The stream would also require complex cooling systems prior to separation, compression, and transport. Therefore, the recovery and purification of CO_2 from the stack gases would necessitate significant additional processing, including energy and cooling water, and environmental/air quality penalties, to achieve the necessary CO_2 concentration for effective storage.

Once separated, the CO_2 must be compressed, requiring significant additional inputs of energy to accomplish compression of the low pressure CO_2 gas to a supercritical fluid, which is equivalent to a pressure increase of approximately 2,200 psia. This is a complicated process that requires complex equipment with numerous stages of compression integrated with heat removal.

Transport

Once the CO_2 is supercritical, it must be transported to a suitable site for storage or sequestration. Transport via pipeline is the only feasible transportation method for CO_2 recovered from MBPP due to the volumes involved. There is only one CO_2 pipeline located within a reasonable proximity to MBPP and it is owned and operated by Denbury Resources. The Denbury Green Pipeline is located approximately 20 miles from MBPP; however, there is no existing or planned pipeline that would connect the Denbury Green Pipeline to MBPP.

It is unknown at this time whether Denbury could or would accept CO_2 from the proposed project, if a pipeline were to be constructed, however, for the purposes of the economic analysis, it has been assumed that a contract would be secured from Denbury Resources and all recovered CO_2 from the proposed project would be accepted into the Green Pipeline.

Storage

Once the CO_2 is captured, it must be stored in a stable and secure reservoir or geologic formation that is not susceptible to acidic erosion. While a case specific evaluation has not been conducted, it is likely suitable storage reservoirs could be found within a reasonable proximity to MBPP. 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 know productions 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. One of the biggest challenges that can be expected is the necessity of identifying old wells and ensuring they are securely plugged. Since a specific site has not been identified, estimating the technical feasibility and costs of this option is difficult and highly uncertain since a well that meets Class VI requirements under the UIC regulations would have to be identified and secured for the proposed project. Other potential storage sites that may be available are located in the Permian Basin, but are more than 470 miles from the proposed project site and there are no existing connecting CO_2 pipelines to this location from MBPP.

Economic Analysis

Although CCS is not technically or environmentally feasible for the proposed project, a site-specific CCS economic analysis was completed at the request of USEPA. A carbon capture and compression plant was specified with cost estimates by an ExxonMobil Research and Engineering Team specializing in CCS technologies. The Team determined that an amine absorber system with regeneration facilities and CO_2 compression would need to be located in a central location to the proposed project's sources and to the required utility plan, which would be required to meet the steam and power requirements for the CO_2 Capture Plant. This utility plant would generate its own GHG emissions. The CCS design therefore includes capture of CO_2 from the FTOs and boilers exhaust stacks as well as the additional CO_2 emissions generated by the utility plant. The system would be designed to achieve ~90% recovery of CO_2 from the exhaust gas. The CO_2 Capture Plant was specified to accept 226 tons of total FTO and boiler exhaust gas per hour to remove 20 total tons of CO_2 per hour due to the proposed project and 16 tons of total exhaust gas per hour to remove 2 tons of CO_2 per hour due to the dedicated utility plant. The additional power generated by this utility plant is exported as a credit to the operating cost of the utility plant.

The carbon capture and compression cost estimate represents the capital and operating expenses associated with the site-specific carbon capture plant. For purposes of the economic analysis below, it is assumed that a contract would be secured from Denbury Resources to accept CO_2 from MBPP, therefore, the transport costs are based on construction and operation and maintenance of a 20-mile pipeline that is eight inches in diameter. This represents an oversimplification of the complexities of the process that would be necessary to secure a long-term disposition for the captured CO_2. The cost estimates for transport and the liability estimate associated with storage were based on the Department of Energy's National Energy Technology Laboratory study "Estimating Carbon Dioxide Transport and Storage Costs", which was recently completed in 2010.

Note that the basis for the cost estimate for storage reflects an oversimplification of since it is a simple transfer of the recovered CO_2 to Denbury and does not estimate costs for items such as site screening and evaluation, injection well construction and equipment, pore space acquisition, and operating and maintenance costs, therefore this cost estimate is at the lowest possible level and may in fact be significantly underestimating the actual cost for storage if this technology were to be pursued. The cost represented for storage relates to liability, which was estimated at $5,000,000 per the DOE/NETL 2010 report.

As shown in Table 4-2, carbon capture for the proposed project is estimated to cost $366 per ton of CO_2 avoided or $50,800,000 annually to avoid ~90% of the CO_2 emissions from the sources and required utility plant. This cost includes operating and capital costs. The total cost for carbon capture is $208,300,000. This is an extraordinarily high cost and would render the proposed project economically unviable if selected.

Table 4-2 Economic Analysis for Carbon Capture and Compression

Cost Type	Units[10]	Cost (millions $)
Carbon Capture Plants - Capital and Operating Expense Estimation		
CO_2 Compressor and Intercoolers	$ (millions)	32.9
Amine Absorber System	$ (millions)	61.3
CO_2 Regeneration/Purification System	$ (millions)	21.5
Blower, Piping, and Ducting	$ (millions)	14.8
Utility Plant - Capital and Operating Expense Estimation		
New Utility Plant – Boiler, Boiler Feed Water Treatment and Blower	$ (millions)	27.7
Cooling Tower, Utilities Header and Piping	$ (millions)	50.1
Fuel, Utilities, Amine	$ (millions) / yr	11.2
Total Expense Estimation		
Operating Expense	$ / Ton CO_2 Avoided	81
Capital Expense	$ / Ton CO_2 Avoided	285.1
Total	**$ / Ton CO_2 Avoided**	**366.1**

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[10] *All monetary estimations have been calculated in 2016 dollars.*

Table 4-3 Economic Analysis for CO_2 Transport[11]

Cost Type	Units	Cost Equation	Cost (millions)
Pipeline Materials	$ Diameter (inches), Length (miles)	$64,632 + $1.85 × L × (330.5 × D^2 + 686.7 × D + 26,960)	2.0
Pipeline Labor	$ Diameter (inches), Length (miles)	$341,627 + $1.85 × L × (343.2 × D^2 + 2,074 × D + 170,013)	8.1
Pipeline Miscellaneous	$ Diameter (inches), Length (miles)	$150,166 + $1.58 × L × (8,417 × D + 7,234)	2.5
Pipeline Right of Way	$ Diameter (inches), Length (miles)	$48,037 + $1.20 × L × (577 × D + 29,788)	0.9
Pipeline Control System	$		0.11
CO_2 Surge Tank	$		1.2
Total Materials and Labor Estimation	$		14.8
Operating and Maintenance Expense Estimation	$ / mile / year	$8,632	3.5
Total Expense Estimation	$		18.3
Amortized Cost[12]	$/yr		3.6
Total Cost per Ton of CO_2 Avoided			
Total Cost	$ / Ton CO_2 Avoided	25.9	

The total estimated cost for CO_2 transport is $3,600,000 per year or $25.9 per ton of CO_2 avoided. This cost is for an eight-inch diameter pipeline 20 miles in length to transport supercritical CO_2 from MBPP to the Denbury Green Pipeline. The cost includes required materials and labor, equipment such as a surge tank and control system, right of way, construction, and operating and maintenance costs.

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[11] *National Energy Technology Laboratory, Estimating Carbon Dioxide Transport and Storage Costs, United States Department of Energy, Page 5, DOE/NETL-2010/1447.*

[12] *A capital charge rate of 19% was assumed with an expected equipment life of 20 years.*

Table 4-4 Economic Analysis for CCS

CCS Technology for CO_2 Emissions	Cost ($ per ton of CO_2 Avoided)	Tons of CO_2 Avoided per Year[13]	Total Annualized Cost[14] (Million $ per year)
Capture and Compression	$366.1	138,812	$50.8
Transport	$25.9	138,812	$3.6
Storage	$7.1[15]	138,812	$1.0
Total CCS Cost	$399.1	138,812	$55.4

The total cost for capturing and compressing CO_2 generated by the proposed project, capturing and compressing CO_2 generated by the CO_2 capture equipment, transporting supercritical CO_2 20 miles, and providing liability coverage for storage of the project's CO_2 is estimated at $399.1 per ton of CO_2 avoided which equates to an annualized cost of $55,400,000 per year. An annualized CCS cost of $55.4 million dollars would render the proposed project unviable, even for this multi-million dollar investment proposed by ExxonMobil.

While CCS is a viable technology to mitigate CO_2 emissions within applicable industries, it is not an available or applicable technology for polyethylene units due to the low pressure, low CO_2 concentration streams that are distributed across multiple sources and the relatively small scale in comparison to a power plant. Based on the aforementioned technological and environmental challenges and the extraordinarily high annualized cost for capture, transport, and storage of CO_2, CCS as a combined technology is not considered technically, environmentally, or economically feasible for reducing GHG emissions from the proposed project. CCS is eliminated as a potential control option in the BACT analysis for CO_2 emissions from the proposed project.

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[13] *This represents ~90% of the total CO_2 emissions from the proposed sources and utility plant.*

[14] *Total Annual Cost represents an amortized cost for the capital expenditure and operating and maintenance costs. A capital charge rate of 19% was assumed with an expected equipment life of 20 years.*

[15] *It is assumed that Denbury Resources will receive CO_2 from the proposed project and will incorporate the entire flow into its operations. Storage costs are therefore estimated to consist of liability, which is $5,000,000 per the DOE/NETL 2010 report.*

4.3.3 Step 3 - Rank Remaining Control Technologies

The remaining feasible control technologies, as listed below, will be selected for the proposed project, therefore ranking is not required.

- Use of low carbon assist gas;
- Use of good operating and maintenance practices;
- Staged operation; and
- Energy efficient design.

4.3.4 Step 4 - Evaluate the Most Effective Controls and Document Results

Step 4 is not applicable since all remaining control technologies will be selected.

4.3.5 Step 5 - Selection of BACT

As a result of these analyses, the use of a low carbon fuel, good operating and maintenance practices, staged operation, and energy efficient design are selected as BACT for the proposed Vent Collection System. The following work practice standards and operating limits are proposed to demonstrate BACT is met:

- Use a low carbon fuel
    - Consume pipeline quality natural gas, or a fuel with a lower carbon content than pipeline quality natural gas, as supplemental fuel to the FTOs and Vent Headers.
- Use of good operating and maintenance practices;
    - LP Vent Header
        - Monitor the composition of the vent gas contained in the LP Vent Header through an online analyzer and record the heating value.
    - FTOs
        - Monitor and record the vent gas flow to 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.

    - Visually inspect burners during routine preventative maintenance outages and prior to start-up to ensure proper

  Refer to Appendix C for a summary of the proposed work practice standards, operating limits, and/or monitoring to ensure good combustion efficiency for the FTOs.

- Elevated Flare

  - Monitor and record the following parameters to demonstrate compliance with flare systems' operating specifications required to achieve the stated DREs:

    1. Monitor and record the vent gas flow to the elevated flare through a flow monitoring system;

    2. 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;

    3. Monitor and record the composition and heating value of the vent gas within the LP Vent Header;

    4. Monitor pilots for presence of flame.

  Refer to Appendix C for a summary of the proposed work practice standards, operating limits, and/or monitoring to ensure good combustion efficiency for the elevated flare.

- Multi-point ground Flare

  - Monitor and record the following parameters to demonstrate compliance with flare systems' operating specifications required to achieve the stated DREs:

    1. Monitor and record the composition of the vent gas within the HP Vent Header;

    2. Monitor and record the pressure of the HP Vent Header;

    3. 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 will be implemented;

    4. 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; and,

5. Monitor pilots for presence of flame.

Refer to Appendix C for a summary of the proposed work practice standards, operating limits, and/or monitoring to ensure good combustion efficiency for the multi-point ground flare.

- Energy Efficient Design
  - Use FTO variable flow air blowers with computer control application to control the excess oxygen based on the incoming feed.
  - Use computer control application to minimize assist gas firing in to the FTO.
  - Use variable assist at elevated flare with computer control application.

  Refer to Appendix C for a summary of the proposed work practice standards, operating limits, and/or monitoring to ensure high combustion efficiency for the vent control system.

- Staged Operation
  - Operation of the control applications to manage the disposition of the vent streams among the Vent Collection System 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.

Appendix C of this application contains a summary of work practice standards, operational requirements, and/or monitoring for the proposed Vent Control System.

4.4 Boilers

The proposed boilers (EPN's: RUPK31 and RUPK32) will only burn pipeline quality sweet natural gas. Each boiler will emit three GHG: CH_4, CO_2, and N_2O. CO_2 will be emitted from the boiler because it is a combustion product of any carbon-containing fuel. CH_4 will be emitted from the boiler 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. CO_2 emissions account for approximately 99 percent of the total CO_2e emissions. As a result, the GHG BACT analysis is focused on CO_2.

4.4.1 Step 1 – Identification of Potential Control Technologies

The following technologies were identified as potential control options for process boilers on available information and data sources:

- Use of low carbon fuels;
- Use of good operating and maintenance practices;
- Energy efficient design; and
- Carbon Capture and Sequestration (CCS)

4.4.1.1 Low Carbon Fuels

A discussed in section 4.2.1.1, the use of natural gas as assist gas is the lowest-carbon fuel available for the proposed project.

4.4.1.2 Good Operating and Maintenance Practices

Good operating and maintenance practices for the boilers are common techniques and are similar to those for the FTOs and RTO.

The boilers will be equipped with SCR for NO_X control; therefore the focus for the burner design will be on combustion efficiency. The burner will be designed to maintain flame stabilization over a range of firing rates since the boilers will be required to operate at reduced firing rates during normal operation.

Good design principles proposed for this project include:

- Manufacturer burner technology maximizes burner stability and performance over a large operating window of fuel gas pressure and composition. The burners for the proposed project will be designed to accommodate the fuel gas composition range and optimize the burner performance for the design operating window.

- The source of fuel gas is pipeline natural gas, which is free of liquids. This will mitigate the risk of burner fouling or damage, which reduces combustion efficiency resulting in increased CO emissions. The fuel will be sampled monthly per requirements set forth in 40 CFR 98 Subpart C.

Operation and maintenance practices will be consistent with the current MBPP practices. Burner inspection and maintenance is typically performed on a planned basis during equipment maintenance down times to allow for entry requiring physical access to inspect/work on the individual components. Boiler inspections typically occur at least every 5 years but may be on a shorter frequency depending upon boiler performance. Inspection records are kept in the boiler equipment filing system. Key inspection steps include:

- Check integrity of burner components (tips, tiles, surrounds),
- Inspect burner spuds for potential fouling,
- Inspect burner air doors and lubrication,
- Inspect all burners before closing main door to check for potential debris,
- Inspect combustion air ducting and dampers, and
- Check burner spud/orifice sizes.

A record will be maintained for any maintenance activity completed on the burner. The burners are inspected during routine scheduled maintenance periods and corrective measures are taken to ensure the highest quality of combustion and flame stability. Tip replacement is conducted, if required.

Proper combustion can be commercially achieved at low excess oxygen levels as measured by online analyzers during normal operation, which results in high boiler thermal efficiency (≥77%) (HHV basis) and low GHG emissions. The excess oxygen at the burners is controlled and minimized via an application resetting the combustion air supply during normal operation. This application minimizes excess air to the extent complete combustion and maximum thermal efficiency is achieved yet safe operation is maintained. Air to fuel ratio control and low excess oxygen alarm in the DCS mitigate the risk of incomplete combustion due to lack of air. This alarm alerts the Operator that minimum excess oxygen has be detected so he/she may monitor the application controlling excess oxygen and correct the situation as necessary.

There may be times when the boiler will operate at higher excess oxygen than the minimum required level to achieve complete combustion. These times may include but are not limited to boiler turndown when extra air is necessary to achieve necessary mixing energy between combustion air and fuel gas.

Good combustion practices for the boilers include appropriate maintenance of equipment (such as periodic burner tune-ups when required) 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. Refer to Appendix C for a summary of the proposed work practice standards, operating limits, and/or monitoring to ensure good combustion efficiency for the boilers.

4.4.1.3 Energy Efficient Design

Each boiler is sized to individually meet the steam demand of the proposed project for redundancy to ensure the plant is provided with adequate steam in the event of planned outages and unexpected shutdown of one boiler. In the event of an unexpected shutdown of one boiler, the operational boiler must event of an unexpected shutdown of one boiler, the operational boiler must rapidly increase its steam production, therefore both boilers must be operating at all times during normal plant operation. The boilers therefore operate in a reduced capacity mode where each boiler produces half of the normal steam demand. This is the typical operating mode for boilers. The service factor represents the estimated shared load of both boilers and accounts for the fact that each boiler operates during normal plant operation (with the exception of planned boiler maintenance), albeit at a reduced rate.

Based on ExxonMobil's operating history and the sizing of utilities including boilers, the design basis of the proposed boilers is to ensure an unexpected boiler shutdown will not cause a disruptive plant wide shut down. The actual sizing for the proposed project takes into account historical boiler reliability and provides redundant capacity to ensure availability of boiler generated steam does not restrict plant operation. Excess boiler capacity comes with an additional capital cost to the proposed project. The design of the boiler, however, ensures that even while operating at a reduced capacity (29% of capacity), there is a nominal impact on combustion efficiency (estimated at 3%) at the normal reduced rates that the boilers will operate.

To maximize thermal efficiency at MBPP, the boilers will be equipped with heat recovery systems to produce steam from waste heat for use throughout the plant.

Specific technologies include the following:

- Economizer – Use of heat exchanger to recover heat from the exhaust gas to preheat incoming 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 exhaust gas, thus improving thermal efficiency.
- Feed Preheat – Use of heat exchangers to increase the incoming temperature of the feed, thereby reducing boiler firing demand.

Good design principles to ensure high boiler thermal efficiency proposed for this project include:

- As a result, the boilers will achieve a thermal efficiency of no less than 77% on a 12-month rolling average basis. Efficiency will be demonstrated by the following equation:

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

4.4.1.4 Carbon Capture and Sequestration (CCS)

Refer to Section 4.3.2.6 for a detailed description of these practices.

4.4.2 Step 2 - Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible unless it is both available and applicable.

4.4.2.1 Low Carbon Fuels

Use of natural gas as a low carbon fuel is technically feasible.

4.4.2.2 Good Operating and Maintenance Practice

Use of good operating and maintenance practice is considered technically feasible.

4.4.2.3 Energy Efficiency

Incorporating use of an economizer, steam generation from process waste heat, and feed preheat into the design of the boilers for energy efficiency is considered technically feasible.

4.4.2.4 Carbon Capture and Sequestration

CCS is an emerging technology that has no successful application at this scale and it is considered a technically, environmentally, and economically infeasible control option for this project. Refer to section 4.3.2.6 for more details of why CCS is not considered further in the BACT analysis.

4.4.3 Step 3 - Rank Remaining Control Technologies

The following technologies and control efficiencies were identified as technically feasible for CO_2 control options for the boilers based on available information and data sources:

- Use of low carbon fuels;
- Use of good operating and maintenance practices; and
- Energy efficient design.

4.4.4 Step 4 - Evaluate the Most Effective Controls and Document Results

Although all fossil fuels contain carbon, the natural gas combusted in this boiler is a low carbon fuel. In the combustion of a fossil fuel, the fuel carbon is oxidized into CO and CO_2. Full oxidation of fuel carbon to CO_2 is desirable because CO has long been a regulated pollutant with established adverse environmental impacts, and because full combustion releases more useful energy within the process. In addition, emitted CO gradually oxidized to CO_2 in the atmosphere.

The use of low carbon fuels and good operating and maintenance practices are inherent in the design and operation of the boilers at MBPP. The boilers will be designed and operated such that thermal efficiency is achieved.

4.4.5 Step 5 - Selection of BACT

As a result of this analysis, the use of natural gas as a low carbon fuel, good operating and maintenance practices, use of an economizer, steam generation from process waste heat, and feed preheat is selected as BACT for the proposed boilers. This finding is consistent with the proposed rule *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Generating Units,* which states[16]:

> Second, all newly constructed sources have options in selecting their design (although it is true that natural gas-fired plants are inherently lower emitting with regard to CO_2 than coal-fired plants). As a result, prospective owners and operators of new sources could readily comply with the proposed emission standards by choosing to construct a NGCC[17] unit.

The proposed emission standard referenced above is:

> The proposed requirements, which are strictly limited to new sources, would require new fossil fuel-fired EGU's greater than 25 megawatt electric (MWe) to meet an output-based standard of 1,000 lb of CO_2 per megawatt-hour (MWh), based on the performance of widely used natural gas combined cycle (NGCC) technology[18].

This proposed rule is currently the only NSPS for GHG, and although it is applicable to electric generating units rather than boilers, it based the emission limitation on sources firing natural gas, without further controls for GHG. Therefore, the controls selected in the top-down BACT analysis for the proposed boilers, specifically firing of natural gas as fuel gas, meet or exceed the controls required in the proposed NSPS for Greenhouse Gases.

4.5 Equipment Component Fugitives

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

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[16] 77 *FedReg 22410*, April 13, 2012.
[17] Natural Gas Combined Cycle
[18] 77 *FedReg 22392*, April 13, 2012.

gas and natural gas lines for the proposed project, but may be emitted from other process lines that are “in-VOC-service”.

4.5.1 Step 1 – Identify Potential Control Technologies

Piping fugitives may be controlled by various techniques, including:

- Installation of leakless technology components to eliminate fugitive emissions sources;
- Implementation of leak detection and repair (LDAR) programs in accordance with applicable state and federal regulations;
- Implementation of alternative monitoring using a remote sensing technology such as infrared cameras; and
- Implementation of audio/visual/olfactory (AVO) leak detection methods.

4.5.2 Step 2 - Eliminate Technically Infeasible Options

4.5.2.1 Leakless Technology

Leakless technology valves are used in situations where highly toxic or otherwise hazardous materials are used. These technologies cannot be repaired without a unit shutdown that often generates additional emissions. Fuel gas and natural gas are not considered highly toxic or hazardous materials and do not warrant the risk of unit shut down for repair. Thus, leakless valves for fuel lines are considered technically impracticable.

4.5.2.2 Instrument LDAR Programs

Use of instrument LDAR is considered technically feasible.

4.5.2.3 Remote Sensing

Use of remote sensing measures is considered technically feasible.

4.5.2.4 AVO Monitoring

Emissions from leaking components can be identified through AVO methods. Natural gas and some process fluids are odorous, making them detectable by olfactory means. Highly odorous compounds are detectable by AVO methods in lower concentrations than would be detected by instrument LDAR and/or remote sensing. Use of as-observed AVO monitoring is considered technically feasible.

4.5.3 Step 3 - Rank Remaining Control Technologies

Instrument LDAR programs and the alternative work practice of remote sensing using an infrared camera have been determined by USEPA to be equivalent methods of piping fugitive controls[19].

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 natural gas leaks are generally are visible and generate hissing, AVO 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.

Review of TCEQ's control efficiency table for applicable 28-series LDAR program shows that the 28LAER program has the highest overall control efficiency for components in VOC service. MBPP currently employs the 28VHP with CNQT program, which achieves 97% control efficiency for gas/vapor components in VOC service, which is equivalent to the most stringent program, 28LAER. Components in gas/vapor service would exclusively include components that may contain GHGs. The proposed project therefore ranks 28VHP with CNQT and 28LAER as LDAR programs that demonstrate the highest control efficiency for GHG-containing components. The instrument LDAR program chosen is 28VHP with CNQT since MBPP currently employs this LDAR program for components in VOC service.

An as-observed AVO program achieves a control efficiency equivalent to 28LAER; therefore, employing this program for components in non-VOC, natural gas service will meet or exceed BACT.

4.5.4 Step 4 - Evaluate the Most Effective Controls and Document Results

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 and visual and audial characteristics of leaks 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 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

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[19] 73 *FedReg* 78199-78219, December 22, 2008.

component nor specifically for natural gas service. Therefore, since the total contribution to the proposed project's CO_2e PTE from piping fugitives is less than 0.2%, which is much less than the statistical accuracy of the development of the factors themselves[20], instrument LDAR programs or their equivalent alternative method, remote sensing, are not economically practicable for controlling the piping fugitive GHGs emissions for this project's natural gas components.

4.5.5 Step 5 - Selection of BACT

The proposed project selects as-observed AVO as BACT for piping components in natural gas service and instrument LDAR *(28VHP with CNQT)* for piping components in VOC service.

Refer to Appendix C for a summary of the proposed work practice standards and operating limits for fugitive equipment components.

4.6 Analyzers

The only practical option for control of GHG emissions from 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 process or controlled in the Vent Collection System. Thermal oxidation was evaluated as an alternative method of control, however, this option was eliminated as BACT because of the net increase in GHG emissions which would result from the use of natural gas fueled burners to supply sufficient oxidization temperature in the reaction zone.

The TRACErase™ Hydrocarbon Emission Eliminator utilizes a constant heat source to allow effective oxidation of intermittent fugitive emission streams as well as continuous source streams. Temperatures in excess of 100 ^{o}F indicate functioning of cartridge heater and in excess of 185^{o} F indicate functioning of catalyst cartridge.

The proposed project will use a temperature sensor to alert personnel when the operating temperature is off target and the unit requires maintenance. Annual preventive maintenance to replace the catalyst cartridge will be performed, which is consistent with current MBPP practices. Refer to Appendix C for a summary of the proposed work practice standards and operating limits for the analyzers proposed to be controlled by TRACErase™ .

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[20] In Appendix B, Table B-2-2, of EPA's *Protocol for Equipment Leak Emissions Estimates* (EPA 453/R-95-017), November 1995, the Agency considered only the upper and lower 95% confidence limits in developing revised SOCMI emission factors.

SECTION 5
OTHER PSD REQUIREMENTS

5.1 Impacts Analysis

An impacts analysis is not being provided with this application in accordance with USEPA's recommendations:

> "Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of USEPA's regulations to demonstrate that a source does not cause or contribute to a violation of the NAAQS is not applicable to GHGs. Thus, we do not recommend that PSD applicants be required to model or conduct ambient monitoring for CO2 or GHGs.[21]"

5.2 GHG Preconstruction Monitoring

A pre-construction monitoring analysis for GHG is not being provided with this application in accordance with USEPA's recommendations:

> "EPA does not consider it necessary for applications to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provision that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs[22]."

5.3 Additional Impacts Analysis

A PSD additional impacts analysis is not being provided with this application in accordance with USEPA's recommendations:

> "Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applications or permitting authorities to assess impacts for GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions order of magnitude larger than the emissions for individual projects that might be analyzed in

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[21] See footnote 1, Page 47.
[22] See footnote 1, Page 48.

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 with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHG[6]."

The Class I area that is located closest to the proposed project is Caney Creek Wilderness Area, which is located over 100 kilometers away.

5.4 Endangered Species

USEPA's issuance of a GHG permit for the proposed project is not anticipated to trigger Section 7 of the federal Endangered Species Act (ESA). Section 7 of the ESA requires that, through consultation (or conferencing for proposed species) with the U.S. Fish and Wildlife Service (USFWS) and/or the National Marine Fisheries Service (NMFS), federal actions do not jeopardize the continued existence of any threatened, endangered, or proposed species or result in the destruction or adverse modification of designated critical habitat.

A Biological Assessment (BA) of the potential effects of the proposed project on species that are protected under the ESA will be completed as necessary. The assessment will include a review of the USFWS and Texas Parks and Wildlife Department's current lists of threatened and endangered species, and determine whether the proposed project has any effect on any of the federally listed threatened or endangered species.

The BA will evaluate threatened and endangered species within the defined "action area", which is defined as "all areas to be affected directly or indirectly by the Federal action (in this case the Federal Action is USEPA issuing the permit) and not merely the immediate area involved in the action."

5.5 Environmental Justice

USEPA is required to implement Executive Order 12898, entitled "Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations," which states in relevant part that "each Federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations." Based on this Executive Order, the USEPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal PSD permits issued by USEPA Regional Offices and states acting under delegations of Federal authority.

A demographic analysis will be conducted to determine whether communities surrounding the proposed project contain minority, low income, or linguistically isolated populations that significantly deviate from county and statewide averages. Public involvement will be facilitated as requested by USEPA.

5.6 Historical Preservation

Section 106 of the National Historic Preservation Act requires that "a federal agency must identify historic properties, consider the effect its proposed action will have on any identified sites, and then consult with the State Historic Preservation Officer on ways to avoid or mitigate any adverse effects. The law does not mandate a particular result. However, it does provide a meaningful opportunity to resolve potential conflicts."

For the proposed project, an assessment of the potential for historic period sites at the project area will be conducted and include the following:

- Review of old USGS topographic maps, and other previously recorded cultural resource sites within the project areas to identifying historic properties;
- Assessing effects on identified historic properties within the project area;
- Resolving adverse effects, including consultation with the State Historic Preservation Officer (SHPO) and adoption of a Memorandum of Agreement; and
- The submission of a formal request for the federal Advisory Council on Historic Preservation's comments in the event that adverse effects are not resolved.

The aforementioned documentation will be submitted subsequent to this application and upon finalization of the project area. The area of potential effects (APE) includes the entire area within which historic properties could be affected by the project. This includes all areas of construction, demolition, and ground disturbance (direct effects) and the broader surrounding area that might experience visual or other effects from the project (indirect effects).

SECTION 6
CONSIDERATIONS FOR GRANTING A PERMIT

Increased North American shale gas production is positive news for the U.S. economy and, in particular, U.S. petrochemical manufacturers who have benefited not only from lower energy costs, but also from the increased availability of advantaged light feedstock such as ethane – both of which lower overall chemical production costs. This has resulted in numerous announcements of North American ethane cracking studies.

ExxonMobil's U.S. Gulf Coast manufacturing facilities are well-positioned to capitalize on the growing U.S. ethane infrastructure, to expand our domestic capability to produce ethylene and polyethylene, and to supply our high quality commodity and specialty products to customers around the world. The proposed investment reflects ExxonMobil's continued confidence in the natural gas-driven revitalization of the U.S. chemical industry.

If ExxonMobil elects to proceed with this project, it could greatly benefit local economies by creating new jobs and economic growth in the U.S. Gulf Coast region. The project is expected to create about 350 full-time jobs and about 10,000 temporary construction jobs; and would be constructed in and integrated into existing ExxonMobil facilities, taking advantage of existing energy infrastructure. It is also estimated that an additional 3,700 permanent jobs would be created in the local community through multiplier effects.

SECTION 7
OTHER ADMINISTRATIVE REQUIREMENTS

The following administrative information related to this permit application is provided on the following Table 7-1. This information includes:

- Company name;
- Company official and associated contact information;
- Technical contact and associated contact information;
- Project location, Standard Industrial Code (SIC), and North American Industry Classification System (NAICS) code;
- Projected start of construction and start of operation dates; and
- Company official signature transmitting the application.

Table 7-1 Administrative Information

I. Applicant Information			
A. Company or Other Legal Name: ExxonMobil Chemical Company (Mont Belvieu Plastics Plant)			
B. Company Official Contact Name: Joe Wolf			
Title: Plant Manager			
Mailing Address: P.O. Box 1653	City: Mont Belvieu	State: Texas	ZIP Code: 77580-1653
Telephone No.: 281-834-9411	E-mail Address: joe.wolf@exxonmobil.com		
C. Technical Contact Name: Benjamin M. Hurst			
Title: Air Permits Advisor			
Company Name: ExxonMobil Chemical Company			
Mailing Address: P.O. Box 4004	City: Baytown	State: Texas	ZIP Code: 77522-4004
Telephone No.: 281-834-1992	E-mail Address: benjamin.m.hurst@exxonmobil.com		
D. Site Name: Mont Belvieu Plastics Plant			
E. Area Name/Type of Facility: Polyethylene Unit			☒ Permanent ☐ Portable
F. Principal Company Product or Business: Plastics Material Manufacturing			
Principal Standard Industrial Classification Code (SIC): 2821			
Principal North American Industry Classification System (NAICS): 325211			
G. Projected Start of Construction Date: 03/01/2013			
Projected Start of Operation Date: 2Q2016			
Hours of Operation: 24 hours/day, 7 days/week, 52 weeks/year			
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):			
Street Address: 13330 Hatcherville Rd			
City/Town: Mont Belvieu	County: Chambers	ZIP Code: 77580	
Latitude (nearest second): 29° 52’ 43” N	Longitude (nearest second): 94° 55’ 12” W		
II. Signature			
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that I understand my signature indicates that this application meets all applicable prevention of significant deterioration permitting application requirements.			
Name: ______________________ **Signature**: ______________________ **Date**: ______________________			*Original Signature Required*

APPENDIX A
GHG EMISSION CALCULATIONS

The following tables are included in this appendix in the following order:

- **GHG Emissions Summary**
- **Fuel Gas Composition and Heating Value**
  - **Table A-1 Representative Vent Gas to FTO**
  - **Table A-2 Representative Vent Gas to Elevated Flare**
  - **Table A-3 Representative Vent Gas to RTO**
  - **Table A-4 Representative Vent Gas to Multi-Point Ground Flare**
  - **Table A-5 Representative Natural Gas**
- **RTO Emissions Calculations**
- **Vent Control System Emissions Calculations**
  - Flameless Thermal Oxidizers Emissions Calculations
  - Flaring Emissions Calculations
  - Pilot Gas Emissions Calculations
- **Boilers Emissions Calculations**
- **Fugitive Emissions Calculations**
- **Analyzers Emissions Calculations**
- **Hexene Tank Emissions Calculations**
- **Cooling Tower Emissions Calculations**
- **Wastewater Emissions Calculations**
- **Miscellaneous Vents Emissions Calculations**

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
GHG Emissions Summary

Annual Emissions: Tons per year CO_2e										
GHG Pollutant	**Total Annual Emissions**	**Regenerative Thermal Oxidizer**	**Vent Collection System**	**Boilers**	**Fugitives**	**Anazlyers**	**Oil Water Separator**	**Cooling Tower**	**Miscellaneous Vents**	**Hexene Tank**
CO_2	130,343	2,221	97,582	30,512	(A)	28	-	-	-	-
N_2O	7	1	5	1	-	-	-	-	-	-
CH_4	14	1	11	2	(A)	-	-	-	-	-
Total GHG mass	130,364	2,223	97,598	30,515	(A)	28	0	0	0	0
GHG CO_2e										
CO_2	130,343	2,221	97,582	30,512	(A)	28	-	-	-	-
N_2O	2,170	310	1,550	310	-	-	-	-	-	-
CH_4	294	21	231	42	(A)	-	-	-	-	-
Total GHG CO_2e	132,807	2,552	99,363	30,864	(A)	28	0	0	0	0

[A] Air contaminant emission rates are estimates only for fugitive sources.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Vent Gas and Fuel Gas Heating Values and Compositions

Table A-1 Representative Vent Gas to FTO

Constituent	Composition (mol%)	MW (lb/lbmol)	Composition (wt%)	HHV (Btu/lbmol)	HHV (Btu/scf)	Carbon Content (lb C / lb Constituent)
Hydrogen	0.1-1%	2.02	0.01-0.07%	123,364	320	--
Nitrogen	40-65%	28.01	35-61%	0	0	--
Methane	1-16%	16.04	1-8%	384,517	998	0.75
Ethene	28-30%	28.05	26-27%	574,308	1,490	0.86
Ethane	0.2-0.6%	30.07	0.2-0.6%	1,095,094	2,841	0.80
Butene	0.05-3%	56.11	0.1-4%	1,095,094	2,841	0.86
Butane	0.5-1%	58.12	1-3%	1,181,639	3,066	0.83
Isopentane	4-10%	72.15	9-21%	1,521,365	3,947	0.83
Hexene	0.3-0.8%	84.16	0.5-5%	1,807,569	4,690	0.86
Hexane	0.1-0.2%	86.18	0.4-0.7%	1,807,569	4,690	0.84
Hexene Isomers	0.1-0.3%	84.16	0.3-0.9%	1,807,569	4,690	0.86
C8+	< 0.1%	114.23	< 0.01%	1,807,569	4,690	0.84
Tetrahydrofuran	< 0.2%	72.11	< 0.2%	1,089,075	2,826	0.67
Toluene	< 0.2%	92.13	< 0.2%	1,702,046	4,416	0.91
CO	0.00%	28.01	0.00%	122,225	317	0.43
CO_2	0.00%	44.01	0.00%	0	0	0.27

Table A-2 Representative Vent Gas to Elevated Flare

Constituent	Composition (mol%)	MW (lb/lbmol)	Composition (wt%)	HHV (Btu/lbmol)	HHV (Btu/scf)	Carbon Content (lb C / lb Constituent)
Hydrogen	1%	2.02	0.11-0.12%	123,364	320	--
Nitrogen	39-50%	28.01	62-72%	0	0	--
Methane	1-15%	16.04	1-14%	384,517	998	0.75
Ethene	29-31%	28.05	45-47%	574,308	1,490	0.86
Ethane	0.2-0.4%	30.07	0-1%	1,095,094	2,841	0.80
Butene	2-2.1%	56.11	6-6.7%	1,095,094	2,841	0.86
Butane	1-1.6%	58.12	3-5%	1,181,639	3,066	0.83
Isopentane	10.6-11.4%	72.15	36-37%	1,521,365	3,947	0.83
Hexene	0.8-1%	84.16	4-5%	1,807,569	4,690	0.86
Hexane	0.2-0.4%	86.18	1-2%	1,807,569	4,690	0.84
Hexene Isomers	0.34-0.36%	84.16	1.59-1.61%	1,807,569	4,690	0.86
C8+	0%	114.23	0%	1,807,569	4,690	0.84
Tetrahydrofuran	0-0.1%	72.11	0-0.4%	1,089,075	2,826	0.67
Toluene	0-0.1%	92.13	0-0.4%	1,702,046	4,416	0.91

Note(s): The values represented in these tables are estimates only and are not values upon which compliance shall be based.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Vent Gas and Fuel Gas Heating Values and Compositions

Table A-3 Representative Vent Gas to RTO

Constituent	Composition (mol%)	MW (lb/lbmol)	Composition (wt%)	HHV (Btu/lbmol)	HHV (Btu/scf)	Carbon Content (lb C / lb Constituent)
Butene	< 0.01%	56.11	< 0.02%	1,170,631	3,037	0.86
Hexene	< 0.02%	84.16	< 0.1%	1,807,569	4,690	0.86
Toluene	< 0.001%	92.13	< 0.01%	1,702,046	4,416	0.91
THF	< 0.002%	72.11	< 0.01%	1,164,557	3,021	0.67
Oxygen	0-21%	32.00	0-23%	0	0	--
Nitrogen	0.3-79%	28.01	1-76%	0	0	--
Methane	0.5-96%	16.04	0.3-90%	384,517	998	0.75
C5+ (as Hexane)	0.001-0.1%	86.18	0.002-1%	1,807,569	4,690	0.84
Ethane	0.01-2%	30.07	0.01-3%	680,211	1,765	0.80
Ethylene	0%	28.05	0%	612,645	1,590	0.86
Propane	0.002-0.3%	44.10	0.003-1%	983,117	2,551	0.82
Butane	0.001-0.2%	58.12	0.002-1%	1,279,191	3,319	0.83
CO	0%	28.01	0%	122,225	317	0.43
CO_2	0.01-2%	44.01	0.01-4%	0	0	0.27

Table A-4 Representative Vent Gas to Multi-Point Ground Flare

Constituent	Composition (mol%)	MW (lb/lbmol)	Composition (wt%)	HHV (Btu/lbmol)	HHV (Btu/scf)	Carbon Content (lb C / lb Constituent)
Hydrogen	0-0.3%	2.02	0-5%	123,364	320	--
Nitrogen	12-26%	28.01	17-29%	0	0	--
Ethene	25-34%	28.05	30-47%	574,308	1,490	0.86
Ethane	0-0.3%	30.07	0-0.3%	1,095,094	2,841	0.80
Butene	0-26%	56.11	0-15%	1,095,094	2,841	0.86
Butane	6-12%	58.12	5-6%	1,181,639	3,066	0.83
Isopentane	31-43%	72.15	15-23%	1,521,365	3,947	0.83
Hexene	0-8%	84.16	0-4%	1,807,569	4,690	0.86
Hexane	0-3%	86.18	0-2%	1,807,569	4,690	0.84
Other C6+	0-3%	84.16	0-2%	1,807,569	4,690	0.86
C8+	0%	114.23	0%	1,807,569	4,690	0.84
Tetrahydrofuran	0-0.1%	72.11	0-0.03%	1,089,075	2,826	0.67
Toluene	0-0.1%	92.13	0-0.03%	1,702,046	4,416	0.91

Table A-5 Representative Natural Gas

Constituent	Composition (mol%)	MW (lb/lbmol)	Composition (wt%)	HHV (Btu/lbmol)	HHV (Btu/scf)	Carbon Content (lb C / lb Constituent)
Hydrogen	0.0%	2.02	0.0%	123,364	320	--
Methane	96%	16.04	90%	384,517	998	0.75
Ethane	1.8%	30.07	3.2%	680,211	1,765	0.80
Ethylene	0.0%	28.05	0.0%	612,645	1,590	0.86
Propane	0.3%	44.10	0.9%	983,117	2,551	0.82
n-Butane	0.2%	58.12	0.6%	1,279,191	3,319	0.83
C5+ (as Hexane)	0.1%	86.18	0.7%	1,807,569	4,690	0.84
Nitrogen	0.3%	28.01	0.5%	0	0	0.00
CO	0.0%	28.01	0.0%	122,225	317	0.43
CO_2	1.6%	44.01	4.2%	0	0	0.27

Note(s): The values represented in these tables are estimates only and are not values upon which compliance shall be based.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Regenerative Thermal Oxidizer
Greenhouse Gas Emissions Calculations

Parameter Name & Variable		Value & Units		Basis/Calculation/Notes
1. General Values and Calculations				
Standard Molar Volume	V_{MS}	385	scf/lb-mol	Based on ideal gas law
Avg. Heat Value of Vent Gas	HV_{AVG}	5.7	Btu/scf	Calculated from representative stream speciation
Total Vent Gas Heat Input to Regenerative Thermal Oxidizer	H	37,048.5	MMBtu/yr	$= Q_V * HV_{AVG}$
Total Regenerative Thermal Oxidizer Vent Gas Volume Flow	Q_V	6,516	MMscf/yr	Based on expected firing rate
Avg. Molecular Weight of Vent Gas	M_V	28.8	lb/lb-mol	Calculated from representative stream speciation
Carbon Content of Vent Gas	F_{cc}	0.002	lb_C/lb_{Gas}	Calculated from representative stream speciation
2. CO_2 Emission Rate Calculations				
CO_2 Annual Emission Rate	=	**2,221**	**TPY**	$= MW_{CO2}/MW_{Carbon} * Q_V * 10^6 * F_{CC} * M_V / V_{MS} / 2000$ lb/ton Equation C-5
3. N_2O Emission Rate Calculations				
N_2O Emission Factor	F_{N2O}	6.0E-04	kg/MMBtu	40 CFR 98, Table C-2
N_2O Annual Emission Rate	=	**1**	**TPY**	$= H * F_{N2O} * 2.205$ lb/kg / 2000 lb/ton Equation C-8b
4. CH_4 Emission Rate Calculations				
CH_4 Emission Factor	F_{CH4}	3.0E-03	kg/MMBtu	40 CFR 98, Table C-2
CH_4 Annual Emission Rate	=	**1**	**TPY**	$= H * F_{CH4} * 2.205$ lb/kg / 2000 lb/ton Equation C-8b
5. CO_2e Emission Rate Calculations				
CO_2 CO_2e Factor	Fe_{CO2}	1	ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor	Fe_{N2O}	310	ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor	Fe_{CH4}	21	ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	=	**2,552**	**TPY**	$= \Sigma (TPY * Fe_x)$

Note(s): The operational parameters are estimated variables that result in the worst case maximum allowable emission rates.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Vent Collection System
Greenhouse Gas Emissions Summary

Parameter Name & Variable		Value & Units		Basis/Calculation/Notes
1. CO_2 Emission Rate Calculations				
CO_2 Combustion Annual Emission Rate	**=**	**95,849**	**TPY**	
CO_2 Pilot Gas Annual Emission Rate	**=**	**1,733**	**TPY**	
CO_2 Annual Emission Rate	**=**	**97,582**	**TPY**	Sum of annual CO_2 emissions from all streams
2. N_2O Emission Rate Calculations				
N_2O Combustion Annual Emission Rate	**=**	**3**	**TPY**	
N_2O Pilot Gas Annual Emission Rate	**=**	**2**	**TPY**	
N_2O Annual Emission Rate	**=**	**5**	**TPY**	Sum of annual N_2O emissions from all streams
3. CH_4 Emission Rate Calculations				
CH_4 Combustion Annual Emission Rate	**=**	**6**	**TPY**	
CH_4 Pilot Gas Annual Emission Rate	**=**	**5**	**TPY**	
CH_4 Annual Emission Rate	**=**	**11**	**TPY**	Sum of annual CH_4 emissions from all streams
4. CO_2e Emission Rate Calculations				
CO_2 CO_2e Factor	Fe_{CO2}	1	ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor	Fe_{N2O}	310	ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor	Fe_{CH4}	21	ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	**=**	**99,363**	**TPY**	$= \Sigma (TPY * Fe_x)$

Note(s): The operational parameters are estimated variables that result in the worst case maximum allowable emission rates.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Flameless Thermal Oxidizer
Greenhouse Gas Emissions Calculations

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
1. General Values and Calculations		
Standard Molar Volume V_{MS}	385 scf/lb-mol	Based on ideal gas law
Avg. Heat Value of Vent Gas HV_{AVG}	639 Btu/scf	Calculated from representative stream speciation
Total Vent Gas Heat Input to Flameless Thermal Oxidizer H	1,167,325 MMBtu/yr	$= Q_V * HV_{AVG}$
Total Flameless Thermal Oxidizer Vent Gas Volume Flow Q_V	1,826 MMscf/yr	Based on expected firing rate
Avg. Molecular Weight of Vent Gas M_V	29.98 lb/lb-mol	Calculated from representative stream speciation
Carbon Content of Vent Gas F_{cc}	0.33 lb_C/lb_{Gas}	Calculated from representative stream speciation
2. CO_2 Emission Rate Calculations		
CO_2 Annual Emission Rate =	**86,631 TPY**	$= MW_{CO2}/MW_{Carbon} * Q_V * 10^6 * F_{CC} * M_V / V_{MS}$ / 2000 lb/ton Equation C-5
3. N_2O Emission Rate Calculations		
N_2O Emission Factor F_{N2O}	6.0E-04 kg/MMBtu	40 CFR 98, Table C-2
N_2O Annual Emission Rate =	**1 TPY**	$= H * F_{N2O} * 2.205$ lb/kg / 2000 lb/ton Equation C-8b
4. CH_4 Emission Rate Calculations		
CH_4 Emission Factor F_{CH4}	3.0E-03 kg/MMBtu	40 CFR 98, Table C-2
CH_4 Annual Emission Rate =	**4 TPY**	$= H * F_{CH4} * 2.205$ lb/kg / 2000 lb/ton Equation C-8b
5. CO_2e Emission Rate Calculations		
CO_2 CO_2e Factor Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate =	**87,025 TPY**	$= \Sigma (TPY * Fe_x)$

Note(s): The operational parameters are estimated variables that result in the worst case maximum allowable emission rates.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Total Elevated Flare
Greenhouse Gas Emissions Summary

Parameter Name & Variable		Value & Units	Basis/Calculation/Notes
1. CO_2 Emission Rate Calculations			
CO_2 Flaring Annual Emission Rate	**=**	**3,608 TPY**	
CO_2 Pilot Gas Annual Emission Rate	**=**	**169 TPY**	
CO_2 Annual Emission Rate	**=**	**3,777 TPY**	Sum of annual CO_2 emissions from all streams
2. N_2O Emission Rate Calculations			
N_2O Flaring Annual Emission Rate	**=**	**1 TPY**	
N_2O Pilot Gas Annual Emission Rate	**=**	**1 TPY**	
N_2O Annual Emission Rate	**=**	**2 TPY**	Sum of annual N_2O emissions from all streams
3. CH_4 Emission Rate Calculations			
CH_4 Flaring Annual Emission Rate	**=**	**1 TPY**	
CH_4 Pilot Gas Annual Emission Rate	**=**	**2 TPY**	
CH_4 Annual Emission Rate	**=**	**3 TPY**	Sum of annual CH_4 emissions from all streams
4. CO_2e Emission Rate Calculations			
CO_2 CO_2e Factor	Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor	Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor	Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	**=**	**4,460 TPY**	$= \Sigma$ (TPY * Fe_x)

Note(s): The operational parameters are estimated variables that result in the worst case maximum allowable emission rates.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Vent Gas to the Elevated Flare
Greenhouse Gas Emissions Calculations

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
1. General Values and Calculations		
Standard Molar Volume V_{MS}	385 scf/lb-mol	Based on ideal gas law
Total Flare Vent Gas Volume Flow Q_V	42 MMscf/yr	Based on expected flaring rate
Avg. Molecular Weight of Vent Gas M_V	34.8 lb/lb-mol	Calculated from representative stream speciation
Avg. Carbon Content of Vent Gas CC_{gas}	0.53 lb_C/lb_{gas}	Calculated from representative stream speciation
CO_2 Emission Factor F_{CO2}	60 kg/MMBtu	40 CFR 98 Subpart Y
Flare Efficiency Eff	98%	For calculation purposes
Flare Efficiency Correction Factor C_F	0.02	Calculated based on 40 CFR 98 Subpart Y
2. CO_2 Emission Rate Calculations		
CO_2 Annual Emission Rate =	**3,608 TPY**	$= Eff * MW_{CO2} / MW_C * Q_V * 10^6 * M_V / V_{MS} * CC_{gas}$ / 2000 lb/ton Equation Y-1a
3. N_2O Emission Rate Calculations		
N_2O Emission Factor F_{N2O}	6.0E-04 kg/MMBtu	40 CFR 98 Subpart Y
N_2O Annual Emission Rate =	**1 TPY**	$= CO_2$ TPY $* F_{N2O} / F_{CO2}$ Equation Y-5
4. CH_4 Emission Rate Calculations		
CH_4 Emission Factor F_{CH4}	3.0E-03 kg/MMBtu	40 CFR 98 Subpart Y
Wt. fraction of carbon in fuel gas from CH_4 f_{CH4}	7.42E-05	Calculated from representative stream speciation
CH_4 Annual Emission Rate =	**1 TPY**	$= (CO_2$ TPY $* F_{CH4} / F_{CO2}) + (CO_2$ TPY $* C_F * MW_{CH4}/MW_{CO2} * f_{CH4})$ Equation Y-4
5. CO_2e Emission Rate Calculations		
CO_2 CO_2e Factor Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate =	**3,939 TPY**	$= \Sigma$ (TPY $* Fe_x$)

Note(s): The operational parameters are estimated variables that result in the worst case maximum allowable emission rates.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Pilot Gas to the Elevated Flare
Greenhouse Gas Emissions Calculations

Parameter Name & Variable		Value & Units	Basis/Calculation/Notes
1. General Values and Calculations			
Standard Molar Volume	V_{MS}	385 scf/lb-mol	Based on ideal gas law
Total Flare Natural Gas Volume Flow	Q_V	333 scf/hr	Design rate
Avg. Molecular Weight of Pilot Gas	M_V	17.0 lb/lb-mol	Calculated from representative stream speciation
Avg. Carbon Content of Pilot Gas	CC_{gas}	0.73 lb_C/lb_{gas}	Calculated from representative stream speciation
CO_2 Emission Factor	F_{CO2}	60 kg/MMBtu	40 CFR 98 Subpart Y
Flare Efficiency	Eff	98%	Based on process knowledge
Flare Efficiency Correction Factor	C_F	0.02	Calculated based on 40 CFR 98 Subpart Y
Annual Period of Pilot Gas Flaring	t	8,760 hr/yr	Based on expected normal firing hours
2. CO_2 Emission Rate Calculations			
CO_2 Annual Emission Rate	**=**	**169 TPY**	= Eff * MW_{CO2} / MW_C * Q_V * t * M_V / V_{MS} * CC_{gas} / 2000 lb/ton Equation Y-1a
3. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	1.0E-04 kg/MMBtu	40 CFR 98 Subpart Y
N_2O Annual Emission Rate	**=**	**1 TPY**	= CO_2 TPY * F_{N2O} / F_{CO2} Equation Y-5
4. CH_4 Emission Rate Calculations			
CH_4 Emission Factor	F_{CH4}	1.0E-03 kg/MMBtu	40 CFR 98 Subpart Y
Wt. fraction of carbon in fuel gas from CH_4	f_{CH4}	0.93	Calculated from representative stream speciation
CH_4 Annual Emission Rate	**=**	**2 TPY**	= (CO_2 TPY * F_{CH4} / F_{CO2}) + (CO_2 TPY * CF * MW_{CH4}/MW_{CO2} * f_{CH4}) Equation Y-4
5. CO_2e Emission Rate Calculations			
CO_2 CO_2e Factor	Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor	Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor	Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	**=**	**521 TPY**	= Σ (TPY * Fe_x)

Note(s): The operational parameters are estimated variables that result in the worst case maximum allowable emission rates.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Total Multi-Point Ground Flare
Greenhouse Gas Emissions Summary

Parameter Name & Variable		Value & Units		Basis/Calculation/Notes
1. CO_2 Emission Rate Calculations				
CO_2 Flaring Annual Emission Rate	**=**	**5,610**	**TPY**	
CO_2 Pilot Gas Annual Emission Rate	**=**	**1,564**	**TPY**	
CO_2 Annual Emission Rate	**=**	**7,174**	**TPY**	Sum of annual CO_2 emissions from all streams
2. N_2O Emission Rate Calculations				
N_2O Flaring Annual Emission Rate	**=**	**1**	**TPY**	
N_2O Pilot Gas Annual Emission Rate	**=**	**1**	**TPY**	
N_2O Annual Emission Rate	**=**	**2**	**TPY**	Sum of annual N_2O emissions from all streams
3. CH_4 Emission Rate Calculations				
CH_4 Flaring Annual Emission Rate	**=**	**1**	**TPY**	
CH_4 Pilot Gas Annual Emission Rate	**=**	**3**	**TPY**	
CH_4 Annual Emission Rate	**=**	**4**	**TPY**	Sum of annual CH_4 emissions from all streams
4. CO_2e Emission Rate Calculations				
CO_2 CO_2e Factor	Fe_{CO2}	1	ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor	Fe_{N2O}	310	ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor	Fe_{CH4}	21	ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	**=**	**7,878**	**TPY**	$= \Sigma (TPY * Fe_x)$

Note(s): The operational parameters are estimated variables that result in the worst case maximum allowable emission rates.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Vent Gas to the Multi-Point Ground Flare
Greenhouse Gas Emissions Calculations

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
1. General Values and Calculations		
Standard Molar Volume V_{MS}	385 scf/lb-mol	Based on ideal gas law
Total Flare Vent Gas Volume Flow Q_V	38 MMscf/yr	Based on expected flaring rate
Avg. Molecular Weight of Vent Gas M_V	42.6 lb/lb-mol	Calculated from representative stream speciation
Avg. Carbon Content of Vent Gas CC_{gas}	0.73 lb_C/lb_{gas}	Calculated from representative stream speciation
CO_2 Emission Factor F_{CO2}	60 kg/MMBtu	40 CFR 98 Subpart Y
Flare Efficiency Eff	99.5%	Based on process knowledge
Flare Efficiency Correction Factor C_F	0.005	Calculated based on 40 CFR 98 Subpart Y
2. CO_2 Emission Rate Calculations		
CO_2 Annual Emission Rate =	**5,610 TPY**	= Eff * MW_{CO2} / MW_C * Q_V * 10^6 * M_V / V_{MS} * CC_{gas} / 2000 lb/ton Equation Y-1a
3. N_2O Emission Rate Calculations		
N_2O Emission Factor F_{N2O}	6.0E-04 kg/MMBtu	40 CFR 98 Subpart Y
N_2O Annual Emission Rate =	**1 TPY**	= CO_2 TPY * F_{N2O} / F_{CO2} Equation Y-5
4. CH_4 Emission Rate Calculations		
CH_4 Emission Factor F_{CH4}	3.0E-03 kg/MMBtu	40 CFR 98 Subpart Y
Wt. fraction of carbon in fuel gas from CH_4 f_{CH4}	0	Calculated from representative stream speciation
CH_4 Annual Emission Rate =	**1 TPY**	= (CO_2 TPY * F_{CH4} / F_{CO2}) + (CO_2 TPY * C_F * MW_{CH4}/MW_{CO2} * f_{CH4}) Equation Y-4
5. CO_2e Emission Rate Calculations		
CO_2 CO_2e Factor Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate =	**5,941 TPY**	= Σ (TPY * Fe_x)

Note(s): The operational parameters are estimated variables that result in the worst case maximum allowable emission rates.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Pilot Gas to the Multi-Point Ground Flare
Greenhouse Gas Emissions Calculations

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
1. General Values and Calculations		
Standard Molar Volume V_{MS}	385 scf/lb-mol	Based on ideal gas law
Total Flare Natural Gas Volume Flow Q_V	3,041 scf/hr	Design rate
Avg. Molecular Weight of Pilot Gas M_V	17.0 lb/lb-mol	Calculated from representative stream speciation
Avg. Carbon Content of Pilot Gas CC_{gas}	0.73 lb_C/lb_{gas}	Calculated from representative stream speciation
CO_2 Emission Factor F_{CO2}	60 kg/MMBtu	40 CFR 98 Subpart Y
Flare Efficiency Eff	99.5%	Based on process knowledge
Flare Efficiency Correction Factor C_F	0.005	Calculated based on 40 CFR 98 Subpart Y
Annual Period of Pilot Gas Flaring t	8,760 hr/yr	Based on expected normal firing hours
2. CO_2 Emission Rate Calculations		
CO_2 Annual Emission Rate =	**1,564 TPY**	= Eff * MW_{CO2} / MW_C * Q_V * t * M_V / V_{MS} * CC_{gas} / 2000 lb/ton Equation Y-1a
3. N_2O Emission Rate Calculations		
N_2O Emission Factor F_{N2O}	1.0E-04 kg/MMBtu	40 CFR 98 Subpart Y
N_2O Annual Emission Rate =	**1 TPY**	= CO_2 TPY * F_{N2O} / F_{CO2} Equation Y-5
4. CH_4 Emission Rate Calculations		
CH_4 Emission Factor F_{CH4}	1.0E-03 kg/MMBtu	40 CFR 98 Subpart Y
Wt. fraction of carbon in fuel gas from CH_4 f_{CH4}	0.93	Calculated from representative stream speciation
CH_4 Annual Emission Rate =	**3 TPY**	= (CO_2 TPY * F_{CH4} / F_{CO2}) + (CO_2 TPY * CF * MW_{CH4}/MW_{CO2} * f_{CH4}) Equation Y-4
5. CO_2e Emission Rate Calculations		
CO_2 CO_2e Factor Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate =	**1,937 TPY**	= Σ (TPY * Fe_x)

Note(s): The operational parameters are estimated variables that result in the worst case maximum allowable emission rates.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Boiler Firing
Greenhouse Gas Emissions Calculations

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
1. General Values and Calculations		
Standard Molar Volume V_{MS}	385 scf/lb-mol	Based on ideal gas law
Avg. Heat Value of Fuel Gas HV_{AVG}	1,006 Btu/scf	Calculated from representative stream speciation
Total Fuel Gas Heat Input to Boilers H	520,344 MMBtu/yr	Based on expected firing rate
Total Boilers Fuel Gas Volume Flow Q_V	517 MMscf/yr	Based on expected firing rate
Avg. Molecular Weight of Fuel Gas M_V	17.0 lb/lb-mol	Calculated from representative stream speciation
Carbon Content of Fuel Gas F_{cc}	0.727 lb_C/lb_{Gas}	Calculated from representative stream speciation
2. CO_2 Emission Rate Calculations		
CO_2 Annual Emission Rate =	**30,512 TPY**	$= MW_{CO2}/MW_{Carbon} * Q_V * F_{CC} * M_V / V_{MS}$ / 2000 lb/ton Equation C-5
3. N_2O Emission Rate Calculations		
N_2O Emission Factor F_{N2O}	6.0E-04 kg/MMBtu	40 CFR 98, Table C-2
N_2O Annual Emission Rate =	**1 TPY**	$= H * F_{N2O} * 2.205$ lb/kg / 2000 lb/ton Equation C-8b
4. CH_4 Emission Rate Calculations		
CH_4 Emission Factor F_{CH4}	3.0E-03 kg/MMBtu	40 CFR 98, Table C-2
CH_4 Annual Emission Rate =	**2 TPY**	$= H * F_{CH4} * 2.205$ lb/kg / 2000 lb/ton Equation C-8b
5. CO_2e Emission Rate Calculations		
CO_2 CO_2e Factor Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate =	**30,864 TPY**	$= \Sigma (TPY * Fe_x)$

Note(s): The operational parameters are estimated variables that result in the worst case maximum allowable emission rates.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Estimated Fugitive Sources
Greenhouse Gas Emissions Calculations

Parameter Name & Variable		**Value & Units**	**Basis/Calculation/Notes**
1. General Values and Calculations			
Annual Period of Usage	t	8,760 hr/yr	Based on expected operating hours
2. CO_2 Emission Rate Calculations			
CO_2 Annual Emission Rate	**=**	**2 TPY**	= lb/hr rate * t / 2,000 lb/ton
3. CH_4 Emission Rate Calculations			
CH_4 Annual Emission Rate	**=**	**17 TPY**	= lb/hr rate * t / 2,000 lb/ton
4. **CO_2e Emission Rate Calculations**			
CO_2 CO_2e Factor	Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor	Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	**=**	**359 TPY**	= Σ (TPY * Fe_x)

Component Name	**Stream Type**		**CH_4 Component Count**	**CO_2 Component Count**	**Emission Factors (lb/hr-count)**	**CH_4 Control Efficiency (%)**	**CO_2 Control Efficiency (%)**	**CH_4 Emissions (tpy)**	**CO_2 Emissions (tpy)**
Valve	Gas/Vapor	with Ethylene	0	0	0.0258	97	0	0.00	0.00
		w/o Ethylene	443	0	0.0089	97	0	0.52	0.00
		Average	0	0	0.0132	97	0	0.00	0.00
	LL	with Ethylene	0	0	0.0459	97	0	0.00	0.00
		w/o Ethylene	0	0	0.0035	97	0	0.00	0.00
		Average	0	0	0.0089	97	0	0.00	0.00
	HL	w/o Ethylene	-	-	0.0007	0	0	-	-
Non-Insulated Flanges	Gas/Vapor	with Ethylene	0	0	0.0053	30	0	0.00	0.00
		w/o Ethylene	1798	80	0.0029	30	0	15.99	1.02
		Average	0	0	0.0039	30	0	0.00	0.00
	LL	with Ethylene	0	0	0.0052	30	0	0.00	0.00
		w/o Ethylene	0	0	0.0005	30	0	0.00	0.00
		Average	0	0	0.0005	30	0	0.00	0.00
	HL	w/o Ethylene	-	-	0.00007	30	0	-	-
Pump Seals	LL	with Ethylene	0	0	0.1440	100	0	0.00	0.00
		w/o Ethylene	0	0	0.0386	100	0	0.00	0.00
		Average	0	0	0.0439	100	0	0.00	0.00
	HL	with Ethylene	-	-	0.0046	100	0	-	-
		w/o Ethylene	-	-	0.0161	100	0	-	-
		Average	-	-	0.0190	100	0	-	-
Agitator	LL	w/o Ethylene	0	0	0.0386	100	0	0.00	0.00
Compressor Seals	All	All	0	0	0.5027	100	0	0.00	0.00
Relief Valve	All	All	5	0	0.2293	100	0	0.09	0.09
Open-ended Lines	All	with Ethylene	-	-	0.0075	97	0	-	-
		w/o Ethylene	-	-	0.0040	97	0	-	-
		Average	-	-	0.0038	97	0	-	-
Sampling Connections	All	All	0	0	0.0330	97	0	0.00	0.00
Totals			**2246**	**80**				**16.60**	**1.11**

Note(s): The operational parameters are estimated variables that result in the worst case maximum allowable emission rates.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Analyzers
Greenhouse Gas Emissions Calculations

Parameter Name & Variable		Value & Units		Basis/Calculation/Notes
1. General Values and Calculations				
Vent Flow Rate	F_V	0.012	ft^3/min	Based on process knowledge
No. of Analyzers	A	35		
Vapor Density	d_V	0.08	lb/ft^3	Based on ideal gas law
Total Analyzer Gas Volume Flow	Q_V	2.02	lb/hr	$= F_V * A * d_V * 60$ min/hr
Molecular Weight of Gas	M_V	28	lb/lbmol	Based on process knowledge
Destruction Efficiency of Analyzers	DRE	98%		Based on process knowledge
Annual Period of Operation	t	8,760	hr/yr	Based on expected operating hours
2. CO_2 Emission Rate Calculations				
CO_2 Annual Emission Rate	**=**	**28**	**TPY**	$= Q_V / M_V * DRE * 2 * MW_{CO2} * t / 2000$ lb/ton; conservatively assumes gas is 100% VOC, and all VOC = ethylene
3. CO_2e Emission Rate Calculations				
CO_2 CO_2e Factor	Fe_{CO2}	1	ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	**=**	**28**	**TPY**	$= \Sigma (TPY * Fe_x)$

Note(s): The operational parameters are estimated variables that result in the worst case maximum allowable emission rates.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Hexene Tank
Greenhouse Gas Emissions Calculations

Parameter Name & Variable		Value & Units	Calculation Notes
1. General Values and Calculations			
Annual Throughput Rate	A_{Em}	55,000,000 gal/yr	Estimate based on process knowledge
2. CO_2 Emission Rate Calculations			
CO_2 Vapor Space Concentration	$CONC_{CO2}$	0 ppmv	Calculated based on site-specific speciation
CO_2 Annual Emission Rate	=	**0 TPY**	$= A_{Em} * CONC_{CO2} / 10^6 / 2000$ lb/ton
3. N_2O Emission Rate Calculations			
N_2O Vapor Space Concentration	$CONC_{N2O}$	0 ppmv	Calculated based on site-specific speciation
N_2O Annual Emission Rate	=	**0 TPY**	$= A_{Em} * 10^6 * CONC_{N2O} / 10^6 / 2000$ lb/ton
3. CH_4 Emission Rate Calculations			
CH_4 Vapor Space Concentration	$CONC_{CH4}$	0 ppmv	Calculated based on site-specific speciation
CH_4 Annual Emission Rate	=	**0 TPY**	$= A_{Em} * 10^6 * CONC_{CH4} / 10^6 / 2000$ lb/ton
4. CO_2e Emission Rate Calculations			
CO_2 CO_2e Factor	Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor	Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor	Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	=	**0 TPY**	$= \Sigma (TPY * Fe_x)$

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Cooling Tower
Greenhouse Gas Emissions Calculations

Parameter Name & Variable		Value & Units	Calculation Notes
1. General Values and Calculations			
Density of Water	d_{H2O}	8.34 lb/gal	
Total Throughput	Q_V	105,122 gal/min	Based on expected flow rate
Annual Period of Usage	t	8,760 hr/yr	Based on expected operating hours
2. CO_2 Emission Rate Calculations			
CO_2 Concentration	$CONC_{CO2}$	0 ppmw	Calculated based on site-specific speciation
CO_2 Annual Emission Rate	**=**	**0 TPY**	$= Q_V * 60$ min/hr $* d_{H2O} * CONC_{CO2} / 10^6 * t / 2000$ lb/ton
3. N_2O Emission Rate Calculations			
N_2O Concentration	$CONC_{N2O}$	0 ppmw	Calculated based on site-specific speciation
N_2O Annual Emission Rate	**=**	**0 TPY**	$= Q_V * 60$ min/hr $* d_{H2O} * CONC_{N2O} / 10^6 * t / 2000$ lb/ton
3. CH_4 Emission Rate Calculations			
CH_4 Concentration	$CONC_{CH4}$	0 ppmw	Calculated based on site-specific speciation
CH_4 Annual Emission Rate	**=**	**0 TPY**	$= Q_V * 60$ min/hr $* d_{H2O} * CONC_{CH4} / 10^6 * t / 2000$ lb/ton
4. CO_2e Emission Rate Calculations			
CO_2 CO_2e Factor	Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor	Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor	Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	**=**	**0 TPY**	$= \Sigma (TPY * Fe_x)$

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Oil Water Separator
Greenhouse Gas Emissions Calculations

Parameter Name & Variable		Value & Units	Calculation Notes
1. General Values and Calculations			
Density of Water	d_{H2O}	8.34 lb/gal	
Total Throughput	Q_V	5 gal/min	Based on expected flow rate
Annual Period of Usage	t	8,760 hr/yr	Based on expected operating hours
2. CO_2 Emission Rate Calculations			
CO_2 Concentration	$CONC_{CO2}$	0 ppmw	Calculated based on site-specific speciation
CO_2 Annual Emission Rate	=	**0 TPY**	$= Q_V * 60$ min/hr $* d_{H2O} * CONC_{CO2} / 10^6 * t /$ 2000 lb/ton
3. N_2O Emission Rate Calculations			
N_2O Concentration	$CONC_{N2O}$	0 ppmw	Calculated based on site-specific speciation
N_2O Annual Emission Rate	=	**0 TPY**	$= Q_V * 60$ min/hr $* d_{H2O} * CONC_{N2O} / 10^6 * t /$ 2000 lb/ton
3. CH_4 Emission Rate Calculations			
CH_4 Concentration	$CONC_{CH4}$	0 ppmw	Calculated based on site-specific speciation
CH_4 Annual Emission Rate	=	**0 TPY**	$= Q_V * 60$ min/hr $* d_{H2O} * CONC_{CH4} / 10^6 * t /$ 2000 lb/ton
4. CO_2e Emission Rate Calculations			
CO_2 CO_2e Factor	Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor	Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor	Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	=	**0 TPY**	$= \Sigma (TPY * Fe_x)$

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Miscellaneous Vents
Greenhouse Gas Emissions Calculations

Parameter Name & Variable		Value & Units	Calculation Notes
1. General Values and Calculations			
Process Flow Rate (Convey Air)	Q	41,000 MMscf/yr	Based on 60 miscellaneous vents from Additive System, Catalyst Manufacturing, and Pellet Sources.
2. CO_2 Emission Rate Calculations			
CO_2 Vapor Space Concentration	$CONC_{CO2}$	0 ppmv	Calculated based on site-specific speciation
CO_2 Annual Emission Rate	**=**	**0 TPY**	$= A_{Em} * CONC_{CO2} / 10^6 / 2000$ lb/ton
3. N_2O Emission Rate Calculations			
N_2O Vapor Space Concentration	$CONC_{N2O}$	0 ppmv	Calculated based on site-specific speciation
N_2O Annual Emission Rate	**=**	**0 TPY**	$= A_{Em} * 10^6 * CONC_{N2O} / 10^6 / 2000$ lb/ton
3. CH_4 Emission Rate Calculations			
CH_4 Vapor Space Concentration	$CONC_{CH4}$	0 ppmv	Calculated based on site-specific speciation
CH_4 Annual Emission Rate	**=**	**0 TPY**	$= A_{Em} * 10^6 * CONC_{CH4} / 10^6 / 2000$ lb/ton
4. CO_2e Emission Rate Calculations			
CO_2 CO_2e Factor	Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor	Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor	Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	**=**	**0 TPY**	$= \Sigma (TPY * Fe_x)$

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.

APPENDIX B
RACT/BACT/LAER CLEARINGHOUSE

ExxonMobil Chemical Company
Mt. Belvieu Plastics Plant
Combustion Sources - Greenhouse Gas Pollutants
RBLC Search Results

					Throughput				Limit 1			Limit 2			Standard Limit		
RBLC ID	Facility Name	State	Permit Date	Process Name		Units	Pollutant	Control Description	Limit	Unit	Avg. Time Condition	Limit	Unit	Avg. Time Condition	Limit	Unit	Avg. Time Condition
LA-0248	DIRECT REDUCTION IRON PLANT	LA	1/27/2011	DRI-108 - DRI Unit #1 Reformer Main Flue Stack	12168	Billion Btu/yr	Carbon Dioxide	the best available technology for controlling CO2e emissions from the DRI Reformer is good combustion practices, the Acid gas separation system, and Energy integration. BACT shall be good combustion practices, which will be adhered to maintain low levels of fuel consumption by the LNB burners.	11.79	MMBTU/ TON OF DRI		0			11.79	MMBTU/ TON OF DRI	
LA-0248	DIRECT REDUCTION IRON PLANT	LA	1/27/2011	DRI-208 - DRI Unit #2 Reformer Main Flue Stack	12168	Billion Btu/yr	Carbon Dioxide	the best available technology for controlling CO2e emissions from the DRI Reformer is good combustion practices, the Acid gas separation system, and Energy integration. BACT shall be good combustion practices, which will be adhered to maintain low levels of fuel consumption by the LNB burners.	11.79	MMBTU/ TON OF DRI		0			11.79	MMBTU/ TON OF DRI	
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	AUXILIARY BOILER (AUX-1)	338	MMBTU/H	Carbon Dioxide	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	117	LB/ MMBTU		0			117	LB/ MMBTU	
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	AUXILIARY BOILER (AUX-1)	338	MMBTU/H	Methane	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0022	LB/ MMBTU		0			0.0022	LB/ MMBTU	
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	AUXILIARY BOILER (AUX-1)	338	MMBTU/H	N2O	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0002	LB/ MMBTU		0			0.0002	LB/ MMBTU	

ExxonMobil Chemical Company
Mt. Belvieu Plastics Plant
Combustion Sources - Greenhouse Gas Pollutants
RBLC Search Results

					Throughput				Limit 1			Limit 2			Standard Limit		
RBLC ID	Facility Name	State	Permit Date	Process Name		Units	Pollutant	Control Description	Limit	Unit	Avg. Time Condition	Limit	Unit	Avg. Time Condition	Limit	Unit	Avg. Time Condition
*LA-0257	SABINE PASS LNG TERMINAL	LA	12/6/2011	Marine Flare	1590	MM BTU/hr	Carbon Dioxide	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	2909	TONS/YR	ANNUAL MAXIMUM	0			0		
*LA-0257	SABINE PASS LNG TERMINAL	LA	12/6/2011	Wet/Dry Gas Flares (4)	0.26	mm btu/hr	Carbon Dioxide	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	133	TONS/YR	ANNUAL MAXIMUM	0			0		
OH-0330	RUMPKE SANITARY LANDFILL	OH	#########	CANDLESTICK FLARE (5)			Methane	FLARE IS CONTROL	25	LB/H		109.45	T/YR		0		
OH-0330	RUMPKE SANITARY LANDFILL	OH	#########	OPEN FLARE			Methane	FLARE IS CONTROL	25	LB/H		109.45	T/YR		0		

ExxonMobil Chemical Company
Mt. Belvieu Plastics Plant
Combustion Sources - Greenhouse Gas Pollutants
RBLC Search Results

RBLC ID	Facility Name	State	Permit Date	Process Name	Throughput		Pollutant	Control Description	Limit 1			Limit 2			Standard Limit		
						Units			Limit	Unit	Avg. Time Condition	Limit	Unit	Avg. Time Condition	Limit	Unit	Avg. Time Condition
*FL-0330	PORT DOLPHIN ENERGY LLC	FL	12/1/2011	Fugitive GHG emissions	0		Carbon Dioxide	a gas and leak detection system will be used.	0			0			0		
*LA-0257	SABINE PASS LNG TERMINAL	LA	12/6/2011	Fugitive Emissions	0		Carbon Dioxide	conduct a leak detection and repair (LDAR) program	89629	TONS/YR	ANNUAL MAXIMUM	0			0		
OH-0281	RUMPKE SANITARY LANDFILL, INC	OH	6/10/2004	FUGITIVE EMISSIONS FROM LANDFILL AND GAS COLLECTION SYSTEM			Methane		45029	T/YR		0			0		

APPENDIX C
WORK PRACTICE STANDARDS AND OPERATIONAL LIMITATIONS TABLE

Table C-1 Work Practice Standards and Operational Limitations Table

ExxonMobil Chemical Company
Table C-1
Work Practice Standards and Operational Limitations Table

Date:	Revised March 2013	Site Name:	Mont Belvieu Plastics Plant
Company Name:	ExxonMobil Chemical Company	Project:	Polyethylene Unit

Air Contaminant Data		
Emission Point		
EPN	**Name**	**Emission Unit Work Practice Standard, Operational Requirement, or Monitoring**
RUPK71	Regenerative Thermal Oxidizer	Consume pipeline quality natural gas, or a fuel with a lower carbon content, as supplemental fuel
		Monitor and record the vent gas flow with a flow monitoring system
		Monitor and record the supplemental fuel gas flow with a flow monitoring system
		Monitor the temperature and maintain the temperature above the demonstrated and/or vendor specified temperature
		Visually inspect burners during routine preventative maintenance outages and prior to start-up to ensure proper performance
PEXVCS 3UF61A/B/C	Flameless Thermal Oxidizers	Consume pipeline quality natural gas, or a fuel with a lower carbon content, as supplemental fuel
		Monitor and record the vent gas flow with a flow monitoring system
		Monitor and record the supplemental fuel gas flow with a flow monitoring system
		Monitor the heat content of the vent gas contained in the LP Vent Header
		Monitor the excess oxygen at the exhaust stack and maintain the excess oxygen above the demonstrated and/or vendor specified temperature
		Monitor the temperature and maintain the temperature above the demonstrated and/or vendor specified temperature
		Visually inspect burners during routine preventative maintenance outages and prior to start-up to ensure proper performance
PEXVCS 3UFLARE62	Elevated Flare	Monitor and record the vent gas flow through a flow monitoring system
		Monitor and record the composition and heating value of the vent gas contained in the LP Vent Header through an online analyzer
		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
		Monitor the pilots for presence of flame
PEXVCS 3UFLARE63	Multi-Point Ground Flare	Monitor and record the pressure of the HP Vent Header
		Monitor and record the composition of the vent gas contained in the HP Vent Header through an online analyzer and record the heating value of the HP Vent Header
		Monitor and maintain a minimum heating value of 800 Btu/scf of the waste gas (adjusted for hydrogen) when the multi-point ground flare system is operating; 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
		Monitor the pressure to the multi-point ground flare to demonstrate that flow routed to the multi-point ground flare system exceeds 4 psig when it is operating; however, if a lower pressure can be demonstrated to achieve the same level of combustion efficiency, then this lower limit will be implemented
		Monitor the pilots for presence of flame
RUPK31 RUPK32	Boiler 31 Boiler 32	Consume pipeline quality natural gas, or a fuel with a lower carbon content, as fuel
		Sample the fuel monthly per the requirements set forth in 40 CFR 98 Subpart C
		Maintain a minimum thermal efficiency ≥ 77% HHV on a 12-month rolling average
PEXFUGEM	Fugitives	Conduct daily as-observed AVO inspection for piping components in non-VOC natural gas service
		Maintain 28 VHP with CNTQ LDAR program for piping components in VOC service
PEXANALZ	Analyzers	Monitor the temperature and maintain the operating temperature above the minimum temperature indicative of a functioning cartridge heater and catalyst cartridge
		Perform preventative maintenance to replace the catalyst cartridge at least annually

EPN = Emission Point Number