

Exhibit 3

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May 21, 2012

Mr. Jeff Robinson
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U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
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**GHG Permit Application
Baytown Olefins Plant
RN1022212925
Ethylene Expansion Unit
File I.A.1.q.(2)**

Dear Sir or Madam:

ExxonMobil Chemical Company (ExxonMobil) is hereby submitting the attached application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas emissions for a new ethylene production unit to be located at ExxonMobil's Baytown Olefins Plant (BOP) in Baytown, Harris County, Texas.

This permit application is submitted pursuant to EPA's Federal Implementation Plan (FIP) 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 C.F.R. §52.2303(d).

ExxonMobil proposes to begin construction on the project in March 1, 2013; therefore the issuance of the GHG PSD permit prior to that date is critical to the project's schedule. ExxonMobil is committed to working closely with EPA Region 6 to have the application review completed in a timely manner.

If you have any questions about the information provided, please contact Benjamin Hurst at benjamin.m.hurst@exxonmobil.com, or (281) 834-1992.

Sincerely,

ExxonMobil Chemical Company

A handwritten signature in blue ink that reads "JEFFREY K. KOVACS". The signature is written in a cursive style and extends across the width of the page.

Jeffrey K. Kovacs, P.E.
Environmental Section Supervisor

Enclosures

cc: Randy Parmley, P.E., Sage Environmental Consulting, L.P.



**Greenhouse Gas
Prevention of Significant Deterioration
Permit Application for
Ethylene Expansion Project**

**ExxonMobil Chemical Company
Baytown Olefins Plant
Baytown, Texas**

May 2012

Prepared by

S A G E

ENVIRONMENTAL CONSULTING

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SECTION 1

INTRODUCTION

ExxonMobil Chemical Company (ExxonMobil) owns and operates an olefins plant in Harris County, Texas known as the Baytown Olefins Plant (BOP). ExxonMobil is hereby requesting an authorization to construct new equipment at the BOP which will allow for an increase in the overall processing of ethylene, 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 BOP 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). This permit application has been prepared based upon EPA's "New Source Review Workshop Manual" and additional GHG guidance documents. This permit application is submitted pursuant to United States Environmental Protection Agency's (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 BOP is located in Harris County. 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. 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 BOP is an existing major source for all criteria pollutants and has a potential to emit (PTE) for GHG greater than 100,000 TPY on a Carbon Dioxide-equivalent (CO₂e) basis and greater than 100 TPY on a mass basis. GHG emissions from the proposed project are Carbon Dioxide (CO₂), Methane (CH₄), and Nitrous Oxide (N₂O), and are expressed as CO₂e. The project GHG emissions from new and modified sources are estimated to be 2,421,675 tons CO₂e per year; 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 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:

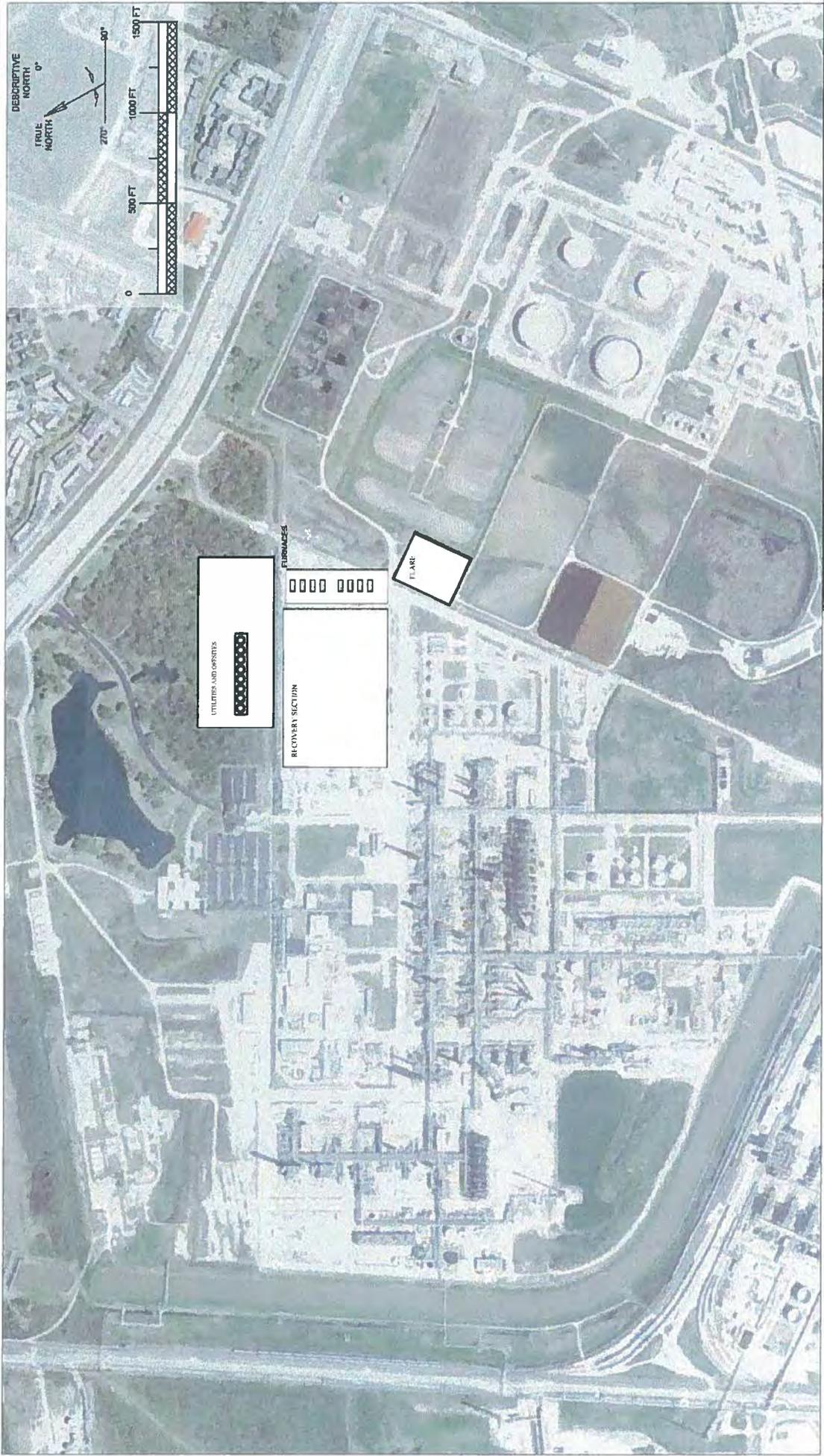
- An area map and plot plan are provided at the end of Section 1.
- The project description is included in Section 2.
- Emission calculation methodologies and an emission point summary table are contained in Section 3.
- Best Available Control Technology (BACT) analysis is presented in Section 4.
- Other 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 presents emission calculations tables.
- Appendix B contains the RACT/BACT/LAER Clearinghouse analysis.

Table 1-1 GHG PSD Applicability Summary

	POLLUTANTS	
	GHG ¹	CO ₂ e
Nonattainment? (yes or no)	No	
Existing site PTE (tpy)?	>100	>100,000
Proposed project emission increases (tpy)	2,414,218	2,421,675
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 CO₂, N₂O, and CH₄ for the proposed project.

² PSD thresholds are found in 40 CFR § 51.21(49)(v).



SAGE ENVIRONMENTAL CONSULTING <i>"Friendly Service, No Surprises!"</i>	Drawing: Plot Plan.dwg	FIGURE 1-2
	Revision #: 1	FACILITY PLOT PLAN
	Date: May 2012	ETHYLENE EXPANSION PROJECT
	Project #: 55-2-24	BAYTOWN OLEFINS PLANT

SECTION 2

PROJECT DESCRIPTION

2.1 Project Description

The proposed project includes construction of eight (8) new steam cracking furnaces and recovery equipment. The major pieces of recovery equipment include a quench tower, caustic wash facilities, a process gas compressor and interstage coolers, a chiller train, a refrigeration system, a deethanizer, an ethylene/ethane (C₂) splitter, and a demethanizer. Bottoms product from the new deethanizer will serve as feed to the existing base plant depropanizer. In addition, a new cooling tower and a new flare system will be constructed. Existing utilities (such as plant air, electric, marginal steam product) will support the proposed project as needed. Figure 2-1 shows the basic process flow of the proposed project.

The emissions from the proposed project will be controlled using the following control technologies: ultra low NO_x burners and Selective Catalytic Reduction (SCR) units on the proposed furnaces, cyclonic separators on the proposed decoking drums, drift eliminators on the cooling tower, and staged flare system to control off gas streams.

2.2 Detailed Project Description

The new facilities will process ethane to produce ethylene and other products. The ethane recovered from the process is recycled to the feed stream. A process flow sequence is shown on the block flow diagram, Figure 2-1. The proposed project will contain typical process equipment including vessels, drums, exchangers, rotating equipment, pipe and piping components, utilities, instrumentation including analyzers, and chemical injection facilities. Design capacity is included in Appendix A and the operating schedule is included in Table 7-1 of this application for each of the proposed sources.

2.2.1 Furnace Section

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

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

2.2.1.1.1 Decoking

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

2.2.1.1.2 Quench Tower

The combined furnace effluent flows into the Quench Tower where it is cooled with quench water. The majority of the dilution steam and some of the heavier hydrocarbons are condensed and exit the tower bottoms. Cooled cracked gases from the tower overhead are caustic scrubbed and compressed. Pyrolysis water in the Quench Tower contains trace amounts of hydrogen sulfide, organic acids, phenols, and some heavy hydrocarbons through direct contact with the process gas. A stripper removes these hydrocarbons from the quench (pyrolysis) water stream that will be used for dilution steam. The heavier hydrocarbons removed from quench water stream are sent to the base plant for recovery. Some process water is removed from the circulating dilution steam and is processed in water treatment facilities before outfall.

2.2.2 Recovery Section

The processing steps within the Recovery Section consist of process gas compression, ammonia removal, caustic scrubbing, and feed drying; deethanizing and acetylene conversion; feed chilling and demethanizing; and ethylene recovery. Refrigeration required for the heat removal in low temperature fractionation is provided by refrigeration systems.

2.2.2.1 Caustic Wash and Compression

Caustic Water Wash Towers are located between compressor stages, where carbon dioxide (CO₂) and hydrogen sulfide (H₂S) are removed in stages of caustic scrubbing. Spent caustic resulting from the caustic scrubbing of the Quench Tower overhead is oxidized in a Wet Air Oxidation Unit prior to neutralization with sulfuric acid and introduction to the wastewater treatment system. Gases from the Wet Air Oxidation Unit are combusted to minimize VOC emissions.

The duty of the process gas compressors is to transfer low pressure gas from the Quench Tower overhead stream to a higher pressure disposition. This process allows the gas to move through the Recovery Section for separation. Once washed and compressed, the Quench Tower overhead stream is dried.

2.2.2.2 Deethanizer and Acetylene Converter

The Deethanizer separates the hydrocarbons with two or less carbon atoms from heavier hydrocarbons. The overhead stream is sent to the Acetylene Converters where acetylene is converted to ethylene and ethane. If the Acetylene Converter requires regeneration online, the gases from the Acetylene Converter regeneration are minimal and are directed to a new Acetylene Converter Regeneration Vent (EPN: ACETCONVXX). The Deethanizer bottoms product, hydrocarbons with more than two carbon atoms, is sent to the BOP Depropanizer in the existing plant facilities. The heavier products from the new facilities such as propylene, propane, 1,3-butadiene, isoprene, pyrolysis gasoline, and benzene are recovered along with the same products from the existing facilities. No increase in GHG emissions are being requested from the proposed Acetylene Converter Regeneration Vent.

2.2.2.3 Demethanizer System

The objective of the Demethanizer System is to separate ethylene from lighter components. The Demethanizer Chilling Train and Demethanizer accomplish this separation through progressively colder temperature levels and distillation. A tail gas stream consisting of methane and hydrogen is produced from the Demethanizer system. This stream can be further processed to purify and recover the commercial value of the hydrogen. If this disposition is unavailable, the tail gas may be routed to the fuel gas system.

2.2.2.4 Ethylene Recovery

Ethylene and ethane are fractionated in the C₂ Splitter to produce the ethylene product. The residual ethane is recycled to the steam cracking furnaces where it is mixed with fresh feed.

2.2.3 Cooling Tower

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

2.2.4 Flare System

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

2.2.5 Wastewater Collection and Treatment System

The proposed project will operate a system to collect process wastewater, separate hydrocarbons from the water and segregate the streams in storage tanks. The wastewater will be further processed in a biological oxidation unit to remove residual hydrocarbons. The treated water will then be discharged to an approved outfall location. No increase in GHG emissions are being requested from the proposed biological oxidation unit.

2.2.6 Storage Tanks

Several new storage tanks will be constructed for the proposed project. These tanks will be ancillary to the process and will store materials such as slop oil, diesel fuel, wastewater, ammonia, compressor wash oil, lube oil, caustic, spent caustic, sulfuric acid, methanol, various additives, and bleach. Some tanks will be routed to control. No increase in GHG emissions are being requested from the proposed storage tanks with atmospheric vents.

2.2.7 Engines

2.2.7.1.1 Backup Generators

The proposed project includes three backup generators, estimated at three (3) megawatt total. Each unit is powered by a diesel engine (EPNs: DIESELXX01-DIESELXX03) and there is one diesel tank associated with each backup generator. The normal operation of the generators is to test for proper operation weekly, in the event it needs to be used in an emergency or backup situation.

2.2.7.1.2 Firewater Booster Pump

The proposed project will provide a booster pump for the existing firewater system. This pump will be powered by a diesel engine (EPN: DIESELXXFW). The normal operation of the booster pump and engine is to test for proper operation weekly, in the event it needs to be used in an emergency or backup situation.

2.3 Planned Maintenance, Start-Up, and Shutdown Activities

The emissions represented in this application reflect the planned maintenance, start up and shut down (MSS) activities requested to be authorized in this new permit application action. Planned MSS activities and associated emissions including equipment degassing/opening, vacuum trucks, frac tanks, and consumables are described below. Planned MSS activities with associated GHG emissions are emitted from the flare and are therefore represented in flare emissions.

2.3.1 Equipment Openings

Equipment is cleared throughout the year in preparation for maintenance activities.

GHG emissions are generated when the cleared vapors are controlled by the flare system. No GHG emissions are proposed from opening the equipment to atmosphere.

2.3.2 Furnace Start-Up

Planned MSS emissions from the proposed furnaces are due to the SCR warm-up during start up. This operation is intermittent and infrequent and is not expected to result in increased GHG emissions compared to normal operation.

2.3.3 Consumables

Small, generally disposable items termed “consumables” will be included as planned MSS activities for the proposed project; however, no increase in GHG emissions are being requested from the planned MSS activities due to consumables.

2.3.4 Vacuum Trucks

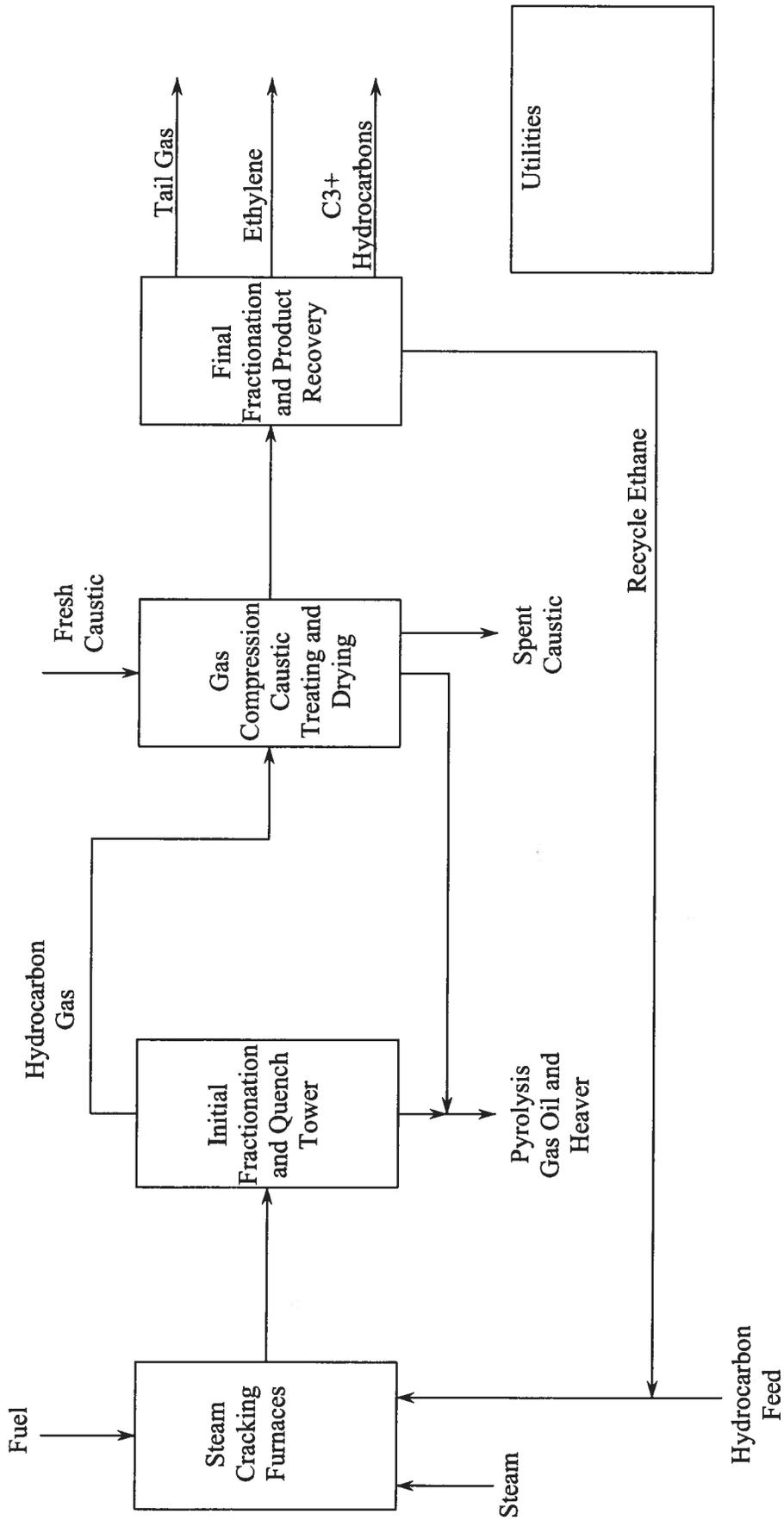
A vacuum truck operates by reducing the pressure on its tank prior to or during pickup of materials and venting released vapors through the vacuum pump and sometimes to a control device. Vacuum trucks are utilized at BOP on a daily basis to transfer materials from one container/vessel to another or from a container/vessel into a closed drain system, usually for purposes of routine maintenance such as: removing the contents of a tank prior to degassing, washing, and/or changing service of the tank; removing water or solids buildup; or collecting materials for treatment in waste/wastewater management units. No increase in GHG emissions are being requested from vacuum truck operations.

2.3.5 Frac Tanks

Frac tank is a generic term for small portable tanks of 500 barrels or less that are used as a repository for cleared/dewatered equipment. The tanks temporarily hold material so that it can be tested prior to reinsertion into the process or treatment in a wastewater treatment unit. Ancillary equipment from fugitives, deoiling/dewatering devices, and waste containers are included with this source. No increase in GHG emissions are being requested from the planned MSS activities due to frac tanks.

2.3.6 Flare System

The flare system is used to control emissions from planned MSS activities related to equipment clearing and startup and shutdown activities.



S A G E ENVIRONMENTAL CONSULTING <i>"Friendly Service, No Surprises!"</i> ®	Drawing: PFD.dwg	FIGURE 2-1
	Revision #: 1	Block Flow Diagram
	Date: May 2012	ExxonMobil
	Project #: 55-2-24	Ethylene Expansion Project

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 CO₂, CH₄, and N₂O. The proposed project emission sources that contribute to these emissions include:

- Furnaces;
- Decoking Drums;
- Flare System;
- Equipment Component Fugitives; and
- Planned Maintenance, Startup, and Shutdown (MSS) activities associated with new emission sources.

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 3-1 located at the end of this section contains an emission point summary for these sources.

3.1 CO₂e Emissions

CO₂e 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 GHG MRR Rule (40 CFR Part 98, Subpart A, Table A-1) were used to calculate CO₂e emissions from estimated emissions of CO₂, CH₄, and N₂O by multiplying the individual GHG pollutant rates by their applicable GWP provided in Table 3-2 below.

Table 3-2 GWP Table

GHG POLLUTANT	GWP (ton pollutant / ton CO₂e)
CO ₂	1
CH ₄	21
N ₂ O	310

3.1.1 Steam Cracking Furnace Emissions

CO₂ emissions are conservatively calculated for a representative fuel scenario using Equation C-5 from the Federal Greenhouse Gas Mandatory Reporting Rule (GHGMRR), 40 CFR 98 Subpart C - General Stationary Fuel Combustion Sources, the fuel annual usage rate assuming 8,760 hours of operation, and the fuel's annual average carbon content. Decoking furnace firing emissions are expected to generate less GHGs; therefore, this approach is conservative.

CH₄ and N₂O emissions from the steam cracking furnaces were calculated based on the emission factor of 1×10^{-3} kg-CH₄ / MMBtu and 1×10^{-4} kg- N₂O / MMBtu (40 CFR 98 Subpart C Table C-2), respectively. The CO₂e 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 CO₂, CH₄, N₂O, and CO₂e for the steam cracking furnaces associated with the proposed project are presented in Table 3-1 at the end of this section.

Emissions from process vents that are routed to the furnace for combustion and control will be estimated using similar methodologies to those stated above.

3.1.2 Decoking Drum Emissions

It is estimated that 25% of the oxidized coke is converted to CO, with the balance oxidizing to CO₂. This CO₂/CO stream is vented through the Decoke Drum Vent. The CO₂e 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 CO₂ expressed as CO₂e for the decoking drum associated with the proposed project are presented in Table 3-1 at the end of this section.

3.1.3 Flare Emissions

A representative off gas mass flow, stream speciation, and higher heating value was used to estimate emissions. CO₂ emissions were estimated according to Equation Y-1a from the Federal GHGMRR 40 CFR 98 Subpart Y. CH₄ and N₂O were calculated according to Equations Y-4 and Y-5, respectively, from the Federal GHGMRR 40 CFR 98 Subpart Y. The CO₂e 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 CO₂, CH₄, N₂O, and CO₂e for the flare system associated with the proposed project are presented in Table 3-1 at the end of this section.

3.1.4 Engines

The CO₂ emission estimates for diesel engines were calculated using 40 CFR §98.33, Equation C-1. CH₄ and N₂O emissions were estimated using Equation C-8b. The CO₂e 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 CO₂, CH₄, N₂O, and CO₂e for the diesel engines associated with the proposed project are presented in Table 3-1 at the end of this section.

3.1.5 Equipment Component Fugitives

Fugitive emission rates of VOC from the piping components and ancillary equipment were estimated using the methods outlined in the TCEQ's *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000*.

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 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 controlled fugitive emission rates, the uncontrolled rates were multiplied by a control factor, which was determined by the LDAR program employed for that source type. For the proposed CH₄ emissions from added fugitive components, emissions were calculated using the appropriate SOCMi ethylene emissions factors and based on the representative stream speciation. The CH₄ emissions, which are also expressed as CO₂e according to the methodology described in Section 3.1, for the added fugitive components from the proposed project are summarized in Appendix A of this application.

The CH₄ emissions, which are also expressed as CO₂e 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. The proposed allowable fugitive emissions of CH₄ expressed as CO₂e for the piping components and ancillary equipment associated with the proposed project are presented in Table 3-1 at the end of this section.

3.2 Planned Maintenance, Startup, and Shutdown (MSS) Emissions

3.2.1 Equipment Opening

Small equipment opening activities with emissions controlled by the proposed flare system will generate CO₂e emissions. The calculation methodology is described in Section 3.2.3. Detailed calculations for this determination are provided in Appendix A to this application.

3.2.2 Furnace Start-up

The proposed project normal operating emissions estimates sufficiently include GHG emission estimates from furnaces during planned MSS; therefore, no additional estimate is necessary.

3.2.3 Flare System

The planned MSS emissions controlled by the proposed flare system will generate CO₂e emissions. The calculation methodology is described in Section 3.2.3. These emissions are not routine emissions and therefore contribute to Intermittent Emissions. Detailed calculations for this determination are provided in Appendix A to this application.

Emission Point Summary

Date:	May 2012	Permit No.:	TBD	Site Name:	Baytown Olefins Plant
Company Name:	ExxonMobil Chemical Company			Project:	Ethylene Expansion

Air Contaminant Data					
EPN	Emission Point		Component or Air Contaminant Name	GHG Emission Rate (ton/yr)	CO ₂ e Emission Rate (ton/yr) ^A
	FIN	Name			
XXAF01-ST	XXAF01	XXA Furnace Combustion Vent	CO ₂	291,161	291,161
			N ₂ O	1	310
			CH ₄	6	126
XXBF01-ST	XXBF01	XXB Furnace Combustion Vent	CO ₂	291,161	291,161
			N ₂ O	1	310
			CH ₄	6	126
XXCF01-ST	XXCF01	XXC Furnace Combustion Vent	CO ₂	291,161	291,161
			N ₂ O	1	310
			CH ₄	6	126
XXDF01-ST	XXDF01	XXD Furnace Combustion Vent	CO ₂	291,161	291,161
			N ₂ O	1	310
			CH ₄	6	126
XXEF01-ST	XXEF01	XXE Furnace Combustion Vent	CO ₂	291,161	291,161
			N ₂ O	1	310
			CH ₄	6	126
XXFF01-ST	XXFF01	XXF Furnace Combustion Vent	CO ₂	291,161	291,161
			N ₂ O	1	310
			CH ₄	6	126
XXGF01-ST	XXGF01	XXG Furnace Combustion Vent	CO ₂	291,161	291,161
			N ₂ O	1	310
			CH ₄	6	126
XXHF01-ST	XXHF01	XXH Furnace Combustion Vent	CO ₂	291,161	291,161
			N ₂ O	1	310
			CH ₄	6	126
XXAB-DEC	XXABDEC	XXA/B Furnace Decoke Vent	CO ₂	149	149
			N ₂ O	-	-
			CH ₄	-	-

^A Air contaminant emission rates are contributions to the CO₂e project compliance total.

EPN = Emission Point Number

FIN = Facility Identification Number

Table 3-1
Emission Point Summary

Date:		May 2012	Permit No.:	TBD	Site Name:	Baytown Olefins Plant
Company Name:		ExxonMobil Chemical Company			Project:	Ethylene Expansion
Air Contaminant Data						
EPN	Emission Point		Name	Component or Air Contaminant Name	GHG Emission Rate (ton/yr)	CO ₂ e Emission Rate (ton/yr) ^A
	FIN					
XXCD-DEC	XXCDDEC	XXC/D Furnace Decoke Vent	CO ₂	149	149	149
			N ₂ O	-	-	-
			CH ₄	-	-	-
XXEF-DEC	XXEFDEC	XXE/F Furnace Decoke Vent	CO ₂	149	149	149
			N ₂ O	-	-	-
			CH ₄	-	-	-
XXGH-DEC	XXGHDEC	XXG/H Furnace Decoke Vent	CO ₂	149	149	149
			N ₂ O	-	-	-
			CH ₄	-	-	-
FLAREXX	FLAREXX	Flare	CO ₂	83,892	83,892	83,892
			N ₂ O	3	3	930
			CH ₄	121	121	2,541
			CO ₂	-	-	-
			N ₂ O	-	-	-
			CH ₄	1	1	21
BOPXXFUG	BOPXXAREA	Fugitives	CO ₂	223	223	223
			N ₂ O	1	1	310
			CH ₄	1	1	21
DIESELXX01	DIESELXX01	Backup Generator Engines	CO ₂	34	34	34
DIESELXX02	DIESELXX02		N ₂ O	1	1	310
DIESELXX03	DIESELXX03		CH ₄	1	1	21
DIESELXXFW	DIESELXXFW	Firewater Booster Pump Engine	CO ₂	2,414,033	2,414,033	2,414,033
			N ₂ O	13	13	4,030
			CH ₄	172	172	3,612
Proposed Project Compliance Totals				2,414,218	2,414,218	2,421,675

^A Air contaminant emission rates are contributions to the CO₂e project compliance total.
 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 CO₂, CH₄, and N₂O emissions is subject to BACT review. The sources subject to BACT review in the proposed project are the new facilities, including new steam cracking furnaces, new decoking drums, new flare system, new engines, and new fugitive components.

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; and
- 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.

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 RBLC was consulted and results are included as Appendix B. Applicable technologies are included in this BACT analysis.

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 Steam Cracking Furnaces

Each furnace will emit three GHG: CH₄, CO₂, and N₂O. CO₂ will be emitted from the furnace because it is a combustion product of any carbon-containing fuel. CH₄ will be emitted from the furnace as a result of any incomplete combustion. N₂O will be emitted from the furnace in trace quantities due to partial oxidation of nitrogen in the air which is used as the oxygen source for the combustion process. CO₂ emissions account for approximately 99% of the total CO_{2e} emissions. As a result, the GHG BACT analysis is focused on CO₂.

All fossil fuels contain carbon and in the combustion of a fossil fuel, the fuel carbon is oxidized into CO and CO₂. Full oxidation of fuel carbon to CO₂ is desirable because full combustion releases more useful energy within the process, thereby minimizing fuel usage and CO₂ emissions.

4.2.1 Step 1 – Identify Potential Control Technology

The following technologies were identified as potential control options for furnaces based 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).

4.2.1.1 *Low Carbon Fuels*

Fuels containing lower concentrations of carbon generate less CO₂ emissions than higher carbon fuels. Low carbon fuel is available for the proposed project.

4.2.1.2 *Good Operating and Maintenance Practices*

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

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

4.2.1.3 *Energy Efficient Design*

The proposed project will use a proprietary furnace design to minimize its carbon footprint. To maximize thermal efficiency at BOP, the steam cracking furnaces will be equipped with heat recovery systems to produce steam from waste heat for use throughout the plant.

Specific technologies include the following:

- Economizer – Use of heat exchanger to recover heat from the exhaust gas to preheat incoming Steam Drum feedwater to attain thermal efficiency.
- Steam Generation from Process Waste Heat – Use of heat exchangers to recover heat from the process effluent to generate high pressure steam. The high pressure steam is then superheated by heat exchange with the furnace exhaust gas, thus improving thermal efficiency.

- Feed Preheat – Use of heat exchangers to increase the incoming temperature of the feed, thereby reducing furnace firing demand.
- Minimize Steam to Hydrocarbon Ratio – Minimizing steam to hydrocarbon ratio reduces the furnace firing.

4.2.1.4 Carbon Capture and Sequestration (CCS)

CCS is a technique used to remove CO₂ from an exhaust gas stream, transport the concentrated CO₂, and store the gas in appropriate geologic formations. CCS requires CO₂ capture before the gas enters the atmosphere, compression of the concentrated and purified CO₂, transportation via pipeline to a site for injection, and storage in an adequate geological formation. Ideal geological formations for sequestration include depleted oil and gas fields, un-mineable coal reserves, underground saline formations, or deep ocean masses.

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 Fuels

Use of low carbon fuels is technically feasible.

4.2.2.2 Use of Good Operating and Maintenance Practices

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

4.2.2.3 Energy Efficient Design

Incorporating use of an economizer, steam generation from process waste heat, feed preheat, and low steam to hydrocarbon ratio into the design of the steam cracking furnaces for energy efficiency is considered technically feasible.

4.2.2.4 Carbon Capture and Sequestration

CCS has been evaluated for the proposed project based on technological, environmental, and economic feasibility. In the guidance documents for GHG permitting, USEPA states¹:

¹ Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, United States Environmental Protection Agency, Page 32, March 2011.

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 CO₂ in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO₂ 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.

The three technologies comprising CCS, capture, transport, and storage were each evaluated separately and are discussed below.

Capture

While the technology for the post-combustion capture of CO₂ may be available, the process has not been demonstrated at the scale of the proposed project nor for sources at natural gas fired facilities. CCS would require additional equipment, operating complexity, and increased energy consumption. 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.

Recovery and purification of CO₂ from the furnace flue gas would require significant additional processing to achieve the necessary CO₂ concentration for effective sequestration. The furnace exhaust streams are not high-purity streams, as recommended in USEPA’s guidance. Instead, the furnace exhausts contain 8 vol% or less CO₂ 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 CO₂ from the stack gases would necessitate significant additional processing, including energy and cooling water, and environmental/air quality penalties, to achieve the necessary CO₂ concentration for effective sequestration.

Transport

Once segregated, the CO₂ must be compressed and transported, requiring significant additional inputs of energy to accomplish compression of CO₂ gas to CO₂ liquid, which is equivalent to a pressure increase of approximately 2,200 psia. There is only one CO₂ pipeline located within a reasonable proximity to BOP and it is owned and operated by Denbury Resources. The Denbury Green Pipeline is located approximately 30 miles from BOP, however, there is no existing or planned connecting pipeline and the Green Pipeline is not currently operational for anthropogenic sources of CO₂.

As discussed below, it is expected that a pipeline of 460 miles in length would have

to be constructed from BOP to a suitable storage site. The diameter of pipeline is expected to be 20 inches to maintain adequate pressure according to a US Department of Energy (DOE) National Energy Technology Laboratory (NETL) study². Typical costs for installation of a pipeline for flat, dry areas can be estimated at \$50,000³ per inch-Diameter per mile, resulting in an estimated installation cost of \$460,000,000.

Storage

Once the CO₂ is captured, it must be stored in a stable and secure reservoir or geologic formation that is not susceptible to acidic erosion. A suitable reservoir or geologic formation is not located within a reasonable proximity to BOP. There are salt dome caverns within 30 miles of the site; however, these limestone formations have not been demonstrated to safely store acid gases such as CO₂, nor is there adequate availability of space. Instead, these domes are used for cyclical storage of liquefied petroleum gases (LPGs) for use in the Gulf Coast as well as for shipment throughout the United States via pipeline. To replace this critical active storage with long-term CO₂ sequestration would necessarily jeopardize energy supplies locally and nationally. Other potential sequestration sites that are presently commercially viable, such as the SACROC enhanced oil recovery unit in the Permian Basin, are more than 460 miles from the proposed project site.

The following are two conclusions drawn by the NETL⁴ study for transport and storage costs relevant to the discussion presented in this section.

- Capital costs associated with CO₂ storage become negligible compared to the cost of transport (i.e. pipeline cost) for pipelines of 50 miles or greater in length.
- Transport and storage operating costs are roughly equivalent for a 25 mile pipeline but transport constitutes a much greater portion of operating expenses at longer pipeline lengths.

Further, as stated in the August 2010 Report of the Interagency Task Force on Carbon Capture and Storage⁵:

Current technologies could be used to capture CO₂ from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not

² National Energy Technology Laboratory, *Estimating Carbon Dioxide Transport and Storage Costs*, United States Department of Energy, Page 10, DOE/NETL-2010/1447

³ *Estimating Carbon Dioxide Transport and Storage Costs*, Page 8.

⁴ *Estimating Carbon Dioxide Transport and Storage Costs*, Page 13.

⁵ 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.

been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO₂ capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment.

Economic Analysis

Although CCS is not technically or environmentally feasible for the proposed project, an economic feasibility analysis was completed for CCS and is presented as Table 4-1 for consideration. The cost estimates for natural gas combined cycle electric generating units contained in the Interagency Task Force report were applied to the proposed project to determine a cost estimate for CCS. This cost estimate is an amortized cost of the capital and operating and maintenance expenses for CCS expressed in an annual cost of US dollars per ton of CO₂ controlled. For the basis of the analysis, it is assumed that the eight furnace stacks are controlled by CCS and 90% of the CO₂ is recovered. The estimate is broken into the three CCS technologies discussed above: capture and compression, transport, and storage. For transport and storage costs that were given in a range, the lower estimate was applied for conservatism.

As shown in Table 4-1, CCS is estimated to cost \$94.08 per ton of CO₂ controlled or \$205,000,000 annually to control 90% of the CO₂ emissions from the furnaces. This is an extraordinarily high cost and would render the proposed project economically unviable if selected.

Based on the aforementioned technological and environmental challenges and extraordinarily high annualized cost for capture, transport, and storage of CO₂, CCS as a combined technology is not considered technically, environmentally, or economically feasible for reducing GHG emissions from the furnaces. CCS is eliminated as a potential control option in this BACT analysis for CO₂ emissions and is not considered further in this analysis.

Table 4-1 Economic Feasibility Analysis for CCS

CCS Technology for CO ₂ Emissions	Cost (\$/ton of CO ₂ Controlled)	Tons of CO ₂ Controlled per Year ⁶	Total Annual Cost ⁷ (Million \$ per year)
Capture and Compression	\$86.18 ⁸	2,414,033	\$185
Transport	\$7.28 ⁹	2,414,033	\$18
Storage	\$0.62 ¹⁰	2,414,033	\$1.5
Total CCS System Cost	\$94.08	N/A	\$205

4.2.3 Step 3 - Rank Remaining Control Technologies

The following technologies and control efficiencies were identified as technically feasible for CO₂ control options for steam cracking furnaces based on available information and data sources:

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

⁶ This represents 90% of the total CO₂ emissions from the eight furnaces.

⁷ Total Annual Cost represents an amortized cost for the capital expenditure and operating and maintenance costs.

⁸ "In terms of cost per tonne of CO₂ captured, values range from \$49/tonne for IGCC to \$95/tonne for NGCC." *Report of the Interagency Task Force on Carbon Capture and Storage*, Page 34.

⁹ "Recent studies have shown that CO₂ pipeline transport costs for a 100 kilometer (62 mile) pipeline transporting 5 million tonnes per year range from approximately \$1 per tonne to \$3 per tonne, depending on the factors discussed above." *Report of the Interagency Task Force on Carbon Capture and Storage*, Page 37.

¹⁰ "Costs associated with CO₂ storage have been estimated to be approximately \$0.4–20/tonne. For example, the IPCC summarized several studies from 2002–2005 reporting estimates in the range \$0.4–12.2/tonne CO₂ stored plus \$0.16–0.30/tonne CO₂ stored (undiscounted) for monitoring." *Report of the Interagency Task Force on Carbon Capture and Storage*, Page 37.

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

4.2.4.1 *Use of Low Carbon Fuels, Good Operating and Maintenance Practices, and Energy Efficient Design*

The use of low carbon fuels and good operating and maintenance practices will be inherent in the design and operation of the proposed steam cracking furnaces. The proposed steam cracking furnaces will be built so that thermal efficiency is achieved.

See Section 4.2.2.4 for a discussion of the adverse environmental impacts and economic infeasibility of CCS.

4.2.5 Step 5 - Selection of BACT

As a result of this analysis, the use of low carbon fuels, good operating and maintenance practices, and energy efficient design is selected as BACT for the proposed steam cracking furnaces. This finding is consistent with the proposed rule *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Generating Units*, which states¹¹:

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 CO₂ 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 NGCC¹² 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 CO₂ per megawatt-hour (MWh), based on the performance of widely used natural gas combined cycle (NGCC) technology¹³.

This proposed rule is currently the only NSPS for GHG, and although it is applicable to electric generating units rather than steam cracking furnaces, 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 furnaces, specifically firing of natural gas or a mix of natural gas and a lower carbon fuel, meet or exceed the controls required in the proposed NSPS for Greenhouse Gases.

¹¹ 77 FedReg 22410, April 13, 2012.

¹² Natural Gas Combined Cycle

¹³ 77 FedReg 22392, April 13, 2012.

4.3 Decoking Activities

The proposed steam cracking furnaces will require periodic decoking to remove coke deposits from the furnace tubes. Coke buildup is inherent in olefin productions. GHG emissions from the decoking activities consist of CO₂ emissions from combustion of the coke build-up on the coils of the new furnaces, which is emitted to the atmosphere through the Decoke Drums.

4.3.1 Step 1 – Identify Potential Control Technologies

An RBLC search revealed there are currently no existing demonstrated control technologies for CO₂ emissions from decoking operations. There are two known ways to minimize CO₂ generated from decoking operations:

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

4.3.2 Step 2 - Eliminate Technically Infeasible Options

4.3.2.1 *Limiting Air/Steam*

Limiting air and/or steam is technically feasible.

4.3.2.1 *Minimizing Coke Generation*

Minimizing the amount of coke generated is considered technically feasible.

4.3.3 Step 3 - Rank Remaining Control Technologies

The following practices were identified as technically feasible for CO₂ control options for decoking operations based on available information and data sources:

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

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

Limiting air and/or steam would reduce CO₂, but it would increase CO emissions from the process by driving the conversion of coke to CO rather than CO₂. Limiting air could also result in an incomplete decoke, which would lead to an increase in the frequency of decoke events. Since CO is a criteria pollutant, it is considered not beneficial and therefore is not an effective control for minimizing CO₂ emissions during decoking operations.

Coke formation is inherent to the design and operation of a steam cracking furnace. Coke build up acts as an insulator and increases pressure drop. Decoking is performed once metallurgical or hydraulic limits are reached. The furnace coking rate will be minimized through design, control, and operations. The design will ensure good feed quality, conversion control, and heat distribution. Minimizing coke build up is the key factor to reduce CO₂ emissions.

4.3.5 Step 5 - Selection of BACT

As a result of this analysis, a combination of design and recommended operations to minimize the coke generation is selected as BACT for the proposed decoking drum.

4.4 Flare System

The flare system provides safe control of gases and supports units during periods of normal, start-up, shutdown, and maintenance operations. 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 safe control of gases vented from the proposed project). 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.

4.4.1 Step 1 – Identify Potential Control Technologies

- Use of low carbon assist gas,
- Use of good operating and maintenance practices, and
- Staged flaring operation.

4.4.1.1 *Low Carbon Assist Gas*

Fuels containing lower concentrations of carbon generate less CO₂ emissions than higher carbon fuels. Pursuant to 40 CFR 98, Subpart C, Table C-1, natural gas is among the lowest carbon fuel listed and is the lowest carbon fuels available for the proposed project.

4.4.1.2 *Good Operating and Maintenance Practices*

Good operating and maintenance practices for a flare include the following:

- Appropriate maintenance of equipment and
- Operation based on recommended design velocity and heating value.

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 flare manufacturer.

4.4.1.3 *Staged Flaring Operation*

The proposed project will install a flare system with staged operation. By segregating these low and high volume streams into different flare dispositions, the proposed project will optimize the amount of assist gas and steam to hydrocarbon ratio required for good combustion. This will minimize the amount of CO₂ generated for routine streams.

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 Assist Gas*

Use of low carbon assist gas is technically feasible.

4.4.2.2 *Good Operating and Maintenance Practices*

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

4.4.2.1 *Staged Flaring*

Use of a staged flare system is considered technically feasible.

4.4.3 Step 3 - Rank Remaining Control Technologies

The following technologies and control efficiencies were identified as technically feasible for CO₂ control options for the flare based on available information and data sources:

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

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

4.4.4.1 *Use of Low Carbon Assist Gas, Good Operating and Maintenance Practices, and Staged Flaring Operation*

The use of low carbon assist gas, good operating and maintenance practices, and staging are inherent in the design and operation of the proposed flare system.

4.4.5 Step 5 - Selection of BACT

As a result of these analyses, staged flaring with natural gas assist and appropriate maintenance of equipment and operation based on recommended design velocity and heating value, are selected as BACT for the proposed flare system.

4.5 Engines

The normal operation of the engines is to test reliability on a weekly basis or operate in an emergency or backup situation; therefore the duty time is sufficiently low and operation is intermittent. A top-down BACT analysis has been included to determine the BACT that is readily available and provides reliable operation of the engines in emergency situations.

4.5.1 Step 1 – Identify Potential Control Technologies

- Use of low carbon fuel and
- Use of good operating and maintenance practices

4.5.1.1 Low Carbon Fuel

An engine can operate when powered with one of three energy sources: electricity, natural gas, or liquid fuel, such as motor gasoline or distillate fuel oil no. 2 (diesel fuel).

4.5.1.2 Good Operating and Maintenance Practices

Good operating and maintenance practices for the engines include the following:

- Operating with recommended fuel to air ratio recommended by the manufacturer (for liquid fuel powered engines) and
- Appropriate maintenance of equipment, such as weekly readiness testing.

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 engine manufacturer.

4.5.2 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.

4.5.2.1 Low Carbon Fuel

The purpose of the engines is to provide a power source during emergencies, which includes site power outages and natural disasters, such as hurricanes. As such, the power source must be available during emergencies. Electricity is not a source that is available during a power outage, which is the specific event for which the backup generators are designed to operate. Natural gas supply may be curtailed during an emergency such as a hurricane, thereby not providing fuel to the engines during the specific event for which the backup generators and firewater booster pump are designed to operate.

The engines must be powered by a liquid fuel that can be stored in a tank and supplied to the engines on demand, such as motor gasoline or diesel. Since the design

of the engines is to operate during an emergency, the fuel that is supplied to the engines must be non-volatile to prevent ignition of any fuel vapors if an ignition source is present during the emergency. Natural gas as a fuel source would also result in a possible ignition during an emergency if used as the fuel due to its volatility. Diesel fuel is a liquid fuel that can be stored in a tank and is non-volatile.

Based on the aforementioned technical challenges for electricity, natural gas and volatile liquid fuel, use of a low carbon fuel is considered technically infeasible for the proposed project.

4.5.2.2 Good Operating and Maintenance Practices

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

4.5.3 Step 3 - Rank Remaining Control Technologies

One control technology remains, therefore ranking is not required.

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

4.5.4.1 Good Operating and Maintenance Practices

The use of good operating and maintenance practices are inherent in the design and operation of the proposed engines.

4.5.5 Step 5 - Selection of BACT

As a result of these analyses, appropriate operation of the engines through proper fuel to air ratios and maintenance based on recommended readiness testing recommended by the manufacturer are selected as BACT for the proposed engines.

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

4.6.1 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.

4.6.2 Step 2 - Eliminate Technically Infeasible Options

4.6.2.1 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.

4.6.2.2 Instrument LDAR Programs

Use of instrument LDAR is considered technically feasible.

4.6.2.3 Remote Sensing

Use of remote sensing measures is considered technically feasible.

4.6.2.4 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.

4.6.3 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 controls¹⁴.

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, olfactory observation is a very effective method for identifying fugitive emissions at a higher frequency than those required by an LDAR program and at lower concentrations than remote sensing can detect.

¹⁴ 73 FedReg 78199-78219, December 22, 2008.

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

Instrument LDAR and/or remote sensing of piping fugitive emissions in fuel gas and natural gas service may be effective methods for detecting GHG emissions from fugitive components; however, the economic practicability of such programs cannot be verified. Specifically, fugitive emissions are estimates only, based on factors derived for a statistical sample and not specific neither to any single piping component nor specifically for natural gas service. Therefore, since the total contribution to the proposed project's CO₂e PTE from piping fugitives is less than 0.003%, which is much less than the statistical accuracy of the development of the factors themselves¹⁵, 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.

4.6.5 Step 5 - Selection of BACT

The proposed project selects as-observed AVO as BACT for piping components in natural gas service and instrument LDAR for piping components in VOC service.

¹⁵ 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 SOCOMI 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.¹⁶”

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 GHGs¹⁷.”

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

¹⁶ See footnote 1, Page 47.

¹⁷ See footnote 1, Page 48.

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 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 GHG⁶.”

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 Corporation – Baytown Olefins Plant (BOP)			
B. Company Official Contact Name: Mr. Jeffrey K. Kovacs, P.E.			
Title: Environmental Supervisor			
Mailing Address: P.O. Box 4004	City: Baytown	State: Texas	ZIP Code: 77522-4004
Telephone No.: 281-834-0101	E-mail Address: jeffrey.k.kovacs@exxonmobil.com		
C. Technical Contact Name: Mr. Benjamin M. Hurst			
Title: Air Permit 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: Baytown Olefins Plant			
E. Area Name/Type of Facility: BOP/Olefins Plant			<input checked="" type="checkbox"/> Permanent <input type="checkbox"/> Portable
F. Principal Company Product or Business: Ethylene Production			
Principal Standard Industrial Classification Code (SIC): 2869			
Principal North American Industry Classification System (NAICS): 325199			
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: 3525 Decker Drive			
City/Town: Baytown	County: Harris	ZIP Code: 77522	
Latitude (nearest second): 29°45'29.58" N		Longitude (nearest second): 95°0'24.22" 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:	JEFFREY K. KOVACS P.E.		
Signature:			Original Signature Required
Date:	5/17/12		

APPENDIX A

GHG EMISSION CALCULATIONS

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

- **GHG Emissions Summary by Source**
- **Representative Fuel Gas Properties**
- **Routine Furnace Operation**
 - Steam Cracking Furnaces Emissions Calculations
 - Decoking Drum Vent Emission Calculations
- **Flare System**
 - Total Flare Emissions
 - Routine Flaring Emission Calculations
 - Intermittent Flaring Emission Calculations
 - Pilot Gas Emission Calculations
- **Fugitive Emissions Calculations**
- **Backup Generator Emissions Calculations**
- **Firewater Booster Pump Emissions Calculations**

Annual Emissions: Tons per year CO ₂ e							
GHG Pollutant	Total Annual Emissions	Total Furnace Firing Emissions	Total Decolking Drum Emissions	Total Flaring Emissions	Fugitives	Backup Generator Engines	Firewater Pump Engine
CO ₂	2,414,033	2,329,288	596	83,892	-	223	34
N ₂ O	13	8	-	3	-	1	1
CH ₄	172	48	-	121	1	1	1
Total GHG mass	2,414,218	2,329,344	596	84,016	1	225	36
GHG CO₂e							
CO ₂	2,414,033	2,329,288	596	83,892	-	223	34
N ₂ O	4,030	2,480	-	930	-	310	310
CH ₄	3,612	1,008	-	2,541	21	21	21
Total GHG CO ₂ e	2,421,675	2,332,776	596	87,363	21	554	365

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

ExxonMobil Chemical Company
 Baytown Olefins Plant
 Fuel and Off Gas Heating Values and Carbon Contents
 Greenhouse Gas Emissions Calculations

REPRESENTATIVE NATURAL GAS						
Constituent	Composition (mol%)	MW (lb/lbmol)	Composition (wt%)	HHV (Btu/lbmol)	HHV (Btu/scf)	Carbon Content (lb C / lb Constituent)
Methane	98%	16.04	95.87%	384,517	977.69	0.75
Ethane	0.68%	30.07	1.25%	680,211	12.00	0.80
Ethylene	0.65%	28.05	1.11%	612,645	10.33	0.86
Propane	0.07%	44.10	0.19%	983,117	1.79	0.82
n-Butane	0.05%	58.12	0.18%	1,279,191	1.66	0.83
CO	0.07%	28.01	0.12%	122,225	0.22	0.43
CO2	0.48%	44.01	1.29%	0	0.00	0.27

REPRESENTATIVE OFF GAS TO FLARE						
Constituent	Composition (mol%)	MW (lb/lbmol)	Composition (wt%)	HHV (Btu/lbmol)	HHV (Btu/scf)	Carbon Content (lb C / lb Constituent)
Hydrogen	0-35%	2.02	0-5%	123,364	320.07	0.00
CO	0-1%	28.01	0-1%	122,225	317.12	0.43
CO2	0-1%	44.01	0-2%	0	0.00	0.27
H2S	0%	34.08	0%	245,590	637.19	0.00
Methane	0-43%	16.04	0-45%	384,517	997.64	0.75
Acetylene	0-1%	26.03	0-1%	612,645	1589.53	0.92
Ethylene	3-62%	28.05	7-60%	612,645	1589.53	0.86
Ethane	11-39%	30.07	22-40%	680,211	1764.83	0.80
Propylene	0-4%	42.08	0-9%	886,703	2300.58	0.86
Propane	0-5%	44.10	0-13%	983,117	2550.73	0.82
1,3-Butadiene	0-1%	54.09	0-1%	1,170,631	3037.24	0.89
1-Butene	0-1%	56.11	0-1%	1,170,631	3037.24	0.86
n-Butane	0-1%	58.12	0-1%	1,279,191	3318.91	0.83
Cyclopentadiene	0-1%	66.10	0-2%	1,423,812	3694.13	0.91
C5 Cyclo	0-1%	66.10	0-1%	1,423,812	3694.13	0.91
Benzene	0-1%	78.11	0-2%	1,423,812	3694.13	0.92
C5 Chain	0-1%	70.13	0-1%	1,524,401	3955.11	0.86
Toluene	0-1%	92.13	0-1%	1,702,046	4416.02	0.91
C6+	0-1%	86.17	0-1%	1,807,569	4689.80	0.84
Pentane	0%	70.13	0%	1,524,401	3955.11	0.86
Nitrogen	0-9%	28.02	0-15%	0	0.00	0.00

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

ExxonMobil Chemical Company
 Baytown Olefins Plant
 Furnace Firing Natural Gas
 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 Natural Gas HV_{AVG}	1,004 Btu/scf	Calculated from representative stream speciation
Natural Gas Heat Input to Furnace H	5,037,000 MMBtu/hr	$= Q_V * HV_{AVG}$
Total Furnace Natural Gas Volume Flow Q_V	5,018 MMscf/yr	Based on expected firing rate
Avg. Molecular Weight of Natural Gas M_V	16.4 lb/lb-mol	Calculated from representative stream speciation
Carbon Content of Natural Gas F_{CC}	0.74 lb _C /lb _{Gas}	Calculated from representative stream speciation
Annual Period of Natural Gas Firing t	8,760 hr/yr	Based on expected firing hours
2. CO₂ Emission Rate Calculations		
CO₂ Annual Emission Rate =	291,161 TPY	$= MW_{CO_2} / MW_{Carbon} * Q_V * F_{CC} * M_V / V_{MS} / 2000 \text{ lb/ton}$ Equation C-5
3. N₂O Emission Rate Calculations		
N ₂ O Emission Factor F_{N_2O}	1.0E-04 kg/MMBtu	40 CFR 98, Table C-2
N₂O Annual Emission Rate =	1 TPY	$= H * F_{N_2O} / .4536 \text{ kg/lb} / 2000 \text{ lb/ton}$ Equation C-8
4. CH₄ Emission Rate Calculations		
CH ₄ Emission Factor F_{CH_4}	1.0E-03 kg/MMBtu	40 CFR 98, Table C-2
CH₄ Annual Emission Rate =	6 TPY	$= H * F_{CH_4} / .4536 \text{ kg/lb} / 2000 \text{ lb/ton}$ Equation C-8
5. CO₂e Emission Rate Calculations		
CO ₂ CO ₂ e Factor F_{eCO_2}	1 ton _{CO₂} /ton _{CO₂e}	40 CFR 98, Table A-1
N ₂ O CO ₂ e Factor F_{eN_2O}	310 ton _{N₂O} /ton _{CO₂e}	40 CFR 98, Table A-1
CH ₄ CO ₂ e Factor F_{eCH_4}	21 ton _{CH₄} /ton _{CO₂e}	40 CFR 98, Table A-1
CO₂e Annual Emission Rate =	291,597 TPY	$= \Sigma (TPY * F_{e_i})$

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.
 The most conservative basis was used to calculate the furnace firing emission by not accounting for reduced firing rates during decoke operations.

ExxonMobil Chemical Company
 Baytown Olefins Plant
 Decoking Drum
 Greenhouse Gas Emissions Calculations

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
1. General Values and Calculations		
Percent Coke Oxidized	50%	Based on process knowledge
Percent Coke Spalled off	50%	Based on process knowledge
Total Solid Coke Released Annually S_A	108,130 lb/yr	Based on process knowledge
2. CO₂ Emission Rate Calculations		
CO ₂ Emission Factor F_{CO_2}	75% CO ₂ /Coke	Based on process knowledge
CO ₂ Annual Emission Rate =	149 TPY	$=S_A / MW_{Carbon} * F_{CO_2} * MW_{CO_2} / 2000$ (lb/ton)
3. CO₂e Emission Rate Calculations		
CO ₂ CO ₂ e Factor F_{eCO_2}	1 ton _{CO₂} /ton _{CO₂e}	40 CFR 98, Table A-1
CO ₂ e Annual Emission Rate =	149 TPY	= TPY rate * F_{eCO_2}

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.
 CH₄ or N₂O emissions are not generated during the decoking process.

ExxonMobil Chemical Company
 Baytown Olefins Plant
 Total Flaring
 Greenhouse Gas Emissions Calculations

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
1. CO₂ Emission Rate Calculations		
CO ₂ Routine Flaring Annual Emission Rate =	36,119 TPY	
CO ₂ Intermittent Flaring Annual Emission Rate =	47,623 TPY	
CO ₂ Pilot Gas Annual Emission Rate =	150 TPY	
CO ₂ Annual Emission Rate =	83,892 TPY	Sum of annual CO ₂ emissions from all streams
2. N₂O Emission Rate Calculations		
N ₂ O Routine Flaring Annual Emission Rate =	1 TPY	
N ₂ O Intermittent Flaring Annual Emission Rate =	1 TPY	
N ₂ O Pilot Gas Annual Emission Rate =	1 TPY	
N ₂ O Annual Emission Rate =	3 TPY	Sum of annual N ₂ O emissions from all streams
3. CH₄ Emission Rate Calculations		
CH ₄ Routine Flaring Annual Emission Rate =	101 TPY	
CH ₄ Intermittent Flaring Annual Emission Rate =	18 TPY	
CH ₄ Pilot Gas Annual Emission Rate =	2 TPY	
CH ₄ Annual Emission Rate =	121 TPY	Sum of annual CH ₄ emissions from all streams
4. CO₂e Emission Rate Calculations		
CO ₂ CO ₂ e Factor Fe _{CO2}	1 ton _{CO2} /ton _{CO2e}	40 CFR 98, Table A-1
N ₂ O CO ₂ e Factor Fe _{N2O}	310 ton _{N2O} /ton _{CO2e}	40 CFR 98, Table A-1
CH ₄ CO ₂ e Factor Fe _{CH4}	21 ton _{CH4} /ton _{CO2e}	40 CFR 98, Table A-1
CO ₂ e Annual Emission Rate =	87,363 TPY	= Σ (TPY * Fe _j)

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

ExxonMobil Chemical Company
 Baytown Olefins Plant
 Routine Flaring
 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 Off Gas Volume Flow Q_V	748 MMscf/yr	Based on expected normal firing rate
Avg. Molecular Weight of Off Gas M_V	16.3 lb/lb-mol	Calculated from representative stream speciation
Avg. Carbon Content of Off Gas CC_{gas}	0.64 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 Correction Factor C_F	0.02	40 CFR 98 Subpart Y
2. CO₂ Emission Rate Calculations		
CO ₂ Annual Emission Rate =	36,119 TPY	= $0.98 * MW_{CO2} / MW_C * Q_V * 10^6 * M_V / V_{MS} * CC_{gas} / 2000$ lb/ton Equation Y-1a
3. N₂O Emission Rate Calculations		
N ₂ O Emission Factor F_{N2O}	6.0E-04 kg/MMBtu	40 CFR 98 Subpart Y
N ₂ O Annual Emission Rate =	1 TPY	= CO_2 TPY * F_{N2O} / F_{CO2} Equation Y-5
4. CH₄ 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}	0.37	Calculated from representative stream speciation
CH ₄ Annual Emission Rate =	101 TPY	= $(CO_2$ TPY * F_{CH4} / F_{CO2}) + $(CO_2$ TPY * $C_F * MW_{CH4} / MW_{CO2} * f_{CH4}$) Equation Y-4
5. CO₂e Emission Rate Calculations		
CO ₂ CO ₂ e Factor Fe_{CO2}	1 ton _{CO2} /ton _{CO2e}	40 CFR 98, Table A-t
N ₂ O CO ₂ e Factor Fe_{N2O}	310 ton _{N2O} /ton _{CO2e}	40 CFR 98, Table A-1
CH ₄ CO ₂ e Factor Fe_{CH4}	21 ton _{CH4} /ton _{CO2e}	40 CFR 98, Table A-1
CO ₂ e Annual Emission Rate =	38,550 TPY	= Σ (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
 Baytown Olefins Plant
 Intermittent Flaring
 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 Off Gas Volume Flow Q_V	426 MMscf/yr	Based on expected normal firing rate
Avg. Molecular Weight of Off Gas M_V	28.8 lb/lb-mol	Calculated from representative stream speciation
Avg. Carbon Content of Off Gas CC_{gas}	0.83 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 Correction Factor C_F	0.02	40 CFR 98 Subpart Y
2. CO₂ Emission Rate Calculations		
CO₂ Annual Emission Rate =	47,623 TPY	= $0.98 * MW_{CO2} / MW_C * Q_V * M_V / V_{MS} * CC_{gas} / 2000 \text{ lb/ton}$ Equation Y-1a
3. N₂O Emission Rate Calculations		
N ₂ O Emission Factor F_{N2O}	6.0E-04 kg/MMBtu	40 CFR 98 Subpart Y
N₂O Annual Emission Rate =	1 TPY	= $CO_2 \text{ TPY} * F_{N2O} / F_{CO2}$ Equation Y-5
4. CH₄ 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}	0.04	Calculated from representative stream speciation
CH₄ Annual Emission Rate =	18 TPY	= $(CO_2 \text{ TPY} * F_{CH4} / F_{CO2}) + (CO_2 \text{ TPY} * C_F * MW_{CH4} / MW_{CO2} * f_{CH4})$ Equation Y-4
5. CO₂e Emission Rate Calculations		
CO ₂ CO ₂ e Factor F_{eCO2}	1 ton _{CO2} /ton _{CO2e}	40 CFR 98, Table A-1
N ₂ O CO ₂ e Factor F_{eN2O}	310 ton _{N2O} /ton _{CO2e}	40 CFR 98, Table A-1
CH ₄ CO ₂ e Factor F_{eCH4}	21 ton _{CH4} /ton _{CO2e}	40 CFR 98, Table A-1
CO₂e Annual Emission Rate =	48,311 TPY	= $\Sigma (TPY * F_{e_j})$

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

ExxonMobil Chemical Company
 Baytown Olefins Plant
 Pilot Gas to 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	300 scf/hr	4 pilots, 75 scfh per pilot
Avg. Molecular Weight of Natural Gas M_V	16.4 lb/lb-mol	Calculated from stream speciation
Avg. Carbon Content of Natural Gas CC_{gas}	0.74 lb _C /lb _{gas}	Calculated from stream speciation
CO ₂ Emission Factor F_{CO_2}	60 kg/MMBtu	40 CFR 98 Subpart Y
Flare Efficiency Correction Factor C_F	0.02	40 CFR 98 Subpart Y
Annual Period of Natural Gas Flaring t	8,760 hr/yr	Based on expected firing hours
2. CO₂ Emission Rate Calculations		
CO ₂ Annual Emission Rate =	150 TPY	= $0.98 * MW_{CO_2} / MW_C * Q_V * t * M_V / V_{MS} * CC_{gas} / 2000$ lb/ton Equation Y-1a
3. N₂O Emission Rate Calculations		
N ₂ O Emission Factor F_{N_2O}	6.0E-04 kg/MMBtu	40 CFR 98 Subpart Y
N ₂ O Annual Emission Rate =	1 TPY	= CO_2 TPY * F_{N_2O} / F_{CO_2} Equation Y-5
4. CH₄ Emission Rate Calculations		
CH ₄ Emission Factor F_{CH_4}	3.0E-03 kg/MMBtu	40 CFR 98 Subpart Y
Wt. fraction of carbon in fuel gas from CH ₄ f_{CH_4}	0.95	Calculated from representative stream speciation
CH ₄ Annual Emission Rate =	2 TPY	= $(CO_2$ TPY * F_{CH_4} / F_{CO_2}) + $(CO_2$ TPY * $C_F * MW_{CH_4} / MW_{CO_2} * f_{CH_4}$) Equation Y-4
5. CO₂e Emission Rate Calculations		
CO ₂ CO ₂ e Factor Fe_{CO_2}	1 ton _{CO_2} /ton _{CO_2e}	40 CFR 98, Table A-1
N ₂ O CO ₂ e Factor Fe_{N_2O}	310 ton _{N_2O} /ton _{CO_2e}	40 CFR 98, Table A-1
CH ₄ CO ₂ e Factor Fe_{CH_4}	21 ton _{CH_4} /ton _{CO_2e}	40 CFR 98, Table A-1
CO ₂ e Annual Emission Rate =	502 TPY	= Σ (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
 Baytown Olefins Plant
 Estimated Fugitive Sources
 Greenhouse Gas Emissions Calculations

Parameter Name & Variable	Value & Units	Calculation Notes
1. General Values and Calculations		
Annual Emission Rate $F_{UGTotal}$	58 TPY	See Table below
2. CO₂ Emission Rate Calculations		
CO ₂ Content CO_2 wt%	0 wt%	
CO ₂ Annual Emission Rate =	0 TPY	= $F_{UGTotal} * CO_2$ wt%
3. CH₄ Emission Rate Calculations		
CH ₄ content CH_4 wt%	5% wt%	Calculated based on site-specific speciation
CH ₄ Annual Emission Rate =	1 TPY	= $F_{UGTotal} * CH_4$ wt%
4. CO₂e Emission Rate Calculations		
CO ₂ CO ₂ e Factor F_{eCO_2}	1 ton _{CO2} /ton _{CO2e}	40 CFR 98, Table A-1
CH ₄ CO ₂ e Factor F_{eCH_4}	21 ton _{CH4} /ton _{CO2e}	40 CFR 98, Table A-1
CO ₂ e Annual Emission Rate =	21 TPY	= $\Sigma (TPY * F_{e_i})$

Estimated Equipment Counts

Component Type and Service	Emission Factor "EF" (lb/hr/source)	LDAR Control Efficiency "CE"	Component Counts			Total Emissions (tpy) = Count * EF * CE * 8760 / 2000
			SOCMI w/o Ethylene	SOCMI Average	SOCMI w/ Ethylene	
Valve-Gas	0.0089	97%	6275	0	0	7.338
	0.0132	97%	0	2975	0	5.160
	0.0258	97%	0	0	625	2.119
Valve-LL	0.0035	97%	3500	0	0	1.610
	0.0089	97%	0	3400	0	3.976
	0.0459	97%	0	0	810	4.885
Valve-HL	0.0007	0%	900	0	0	2.759
	0.0005	0%	0	0	0	0.000
Pump-LL	0.0386	85%	75	0	0	1.902
	0.0439	85%	0	35	0	1.009
	0.144	85%	0	0	15	1.419
Pump-HL	0.0161	0%	10	0	0	0.705
	0.019	0%	0	5	0	0.416
	0.0046	0%	0	0	0	0.000
Compressor-Gas	0.5027	85%	12	0	0	3.963
ARV-Gas	0.2293	97%	5	0	0	0.151
RVLV-Gas	0.2293	97%	65	80	25	5.122
RVLV-LL	0.0035	97%	35	0	0	0.016
	0.0089	97%	0	15	0	0.018
	0.0459	97%	0	0	5	0.030
Connector-Gas	0.0029	97%	18425	0	0	7.021
	0.0039	97%	0	9550	0	4.894
	0.0053	97%	0	0	1450	1.010
Connector-LL	0.0005	97%	7125	6750	0	0.912
	0.0052	97%	0	0	1125	0.769
Connector-HL	0.00007	30%	2225	0	0	0.478
Agitator-LL	0.0386	85%	10	0	0	0.254
	0.0439	85%	0	0	0	0.000
	0.144	85%	0	0	0	0.000
SCONN-LL	0.033	97%	5	0	0	0.022
Total Fugitive Emissions (tpy)						57.96

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

ExxonMobil Chemical Company
 Baytown Olefins Plant
 Backup Generator Engines
 Greenhouse Gas Emissions Calculations

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
1. General Values and Calculations		
Total Generator Capacity W	3 MW	Based on process knowledge
Avg. Heat Value of Fuel Gas HV_{AVG}	0.14 MMBtu/gal	Table C-1 for Distillate Fuel Oil No. 2
Annual Heat Input to Engine H_A	2,729 MMBtu/yr	Based on process knowledge
2. CO₂ Emission Rate Calculations		
CO ₂ Emission Factor F_{CO_2}	73.96 kg/MMBtu	40 CFR 98, Table C-1
CO ₂ Annual Emission Rate =	223 TPY	$=H_A * F_{CO_2} * 2.205 \text{ lb/kg} / 2000 \text{ lb/ton}$ Equation C-1
3. N₂O Emission Rate Calculations		
N ₂ O Emission Factor F_{N_2O}	6.0E-04 kg/MMBtu	40 CFR 98, Table C-2
N ₂ O Annual Emission Rate =	1 TPY	$=H_A * F_{N_2O} * 2.205 \text{ lb/kg} / 2000 \text{ lb/ton}$ Equation C-8b
4. CH₄ Emission Rate Calculations		
CH ₄ Emission Factor F_{CH_4}	3.0E-03 kg/MMBtu	40 CFR 98, Table C-2
CH ₄ Annual Emission Rate =	1 TPY	$=H_A * F_{CH_4} * 2.205 \text{ lb/kg} / 2000 \text{ lb/ton}$ Equation C-8b
5. CO₂e Emission Rate Calculations		
CO ₂ CO ₂ e Factor F_{eCO_2}	1 ton _{CO₂} /ton _{CO₂e}	40 CFR 98, Table A-1
N ₂ O CO ₂ e Factor F_{eN_2O}	310 ton _{N₂O} /ton _{CO₂e}	40 CFR 98, Table A-1
CH ₄ CO ₂ e Factor F_{eCH_4}	21 ton _{CH₄} /ton _{CO₂e}	40 CFR 98, Table A-1
CO ₂ e Annual Emission Rate =	554 TPY	$= \Sigma (\text{TPY} * F_{e_i})$

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

ExxonMobil Chemical Company
 Baytown Olefins Plant
 Firewater Pump Engine
 Greenhouse Gas Emissions Calculations

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
1. General Values and Calculations		
Total Engine Capacity hp	600 hp	Based on process knowledge
Avg. Heat Value of Fuel Gas HV _{AVG}	0.14 MMBtu/gal	Table C-1 for Distillate Fuel Oil No. 2
Annual Heat Input to Engine H _A	407 MMBtu/yr	Based on process knowledge
2. CO₂ Emission Rate Calculations		
CO ₂ Emission Factor F _{CO2}	73.96 kg/MMBtu	40 CFR 98, Table C-1
CO ₂ Annual Emission Rate =	34 TPY	=H _A * F _{CO2} * 2.205 lb/kg / 2000 lb/ton Equation C-1
3. N₂O Emission Rate Calculations		
N ₂ O Emission Factor F _{N2O}	6.0E-04 kg/MMBtu	40 CFR 98, Table C-2
N ₂ O Annual Emission Rate =	1 TPY	=H _A * F _{N2O} * 2.205 lb/kg / 2000 lb/ton Equation C-8b
4. CH₄ 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 _A * F _{CH4} * 2.205 lb/kg / 2000 lb/ton Equation C-8b
5. CO₂e Emission Rate Calculations		
CO ₂ CO ₂ e Factor F _{eCO2}	1 ton _{CO2} /ton _{CO2e}	40 CFR 98, Table A-1
N ₂ O CO ₂ e Factor F _{eN2O}	310 ton _{N2O} /ton _{CO2e}	40 CFR 98, Table A-1
CH ₄ CO ₂ e Factor F _{eCH4}	21 ton _{CH4} /ton _{CO2e}	40 CFR 98, Table A-1
CO ₂ e Annual Emission Rate =	365 TPY	= Σ (TPY * F _e)

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
 Baytown Olefins Plant
 Furnaces - 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		Avg. Time Condition
					Units	Billion Btu/yr			Limit	Unit	Limit	Unit	Limit	Unit	
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 CO ₂ e 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 CO ₂ e 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	N ₂ O	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0002	LB/MMBTU	0		0.0002	LB/MMBTU	

ExxonMobil Chemical Company
 Baytown Olefins Plant
 Decoking Drum - 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	Value			Limit	Unit	Limit	Unit	Limit	Unit
TX-0550	BASF FINA NAFTA REGION OLEFINS COMPLEX	TX	2/10/2010	N-18, DECKING DRUM	26625	LB COKE/CYCLE	Carbon Dioxide				0			0

* Note was from BASF permit and was not obtained during the RBLC search.

ExxonMobil Chemical Company
 Baytown Olefins Plant
 Flare - 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
*LA-0257	SABINE PASS LNG TERMINAL	LA	12/16/2011	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	2505	TONS/YR	ANNUAL MAXIMUM	0					0
*LA-0257	SABINE PASS LNG TERMINAL	LA	12/16/2011	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	RUMPKS SANITARY LANDFILL	OH	12/23/2008	CANDLESTICK FLARE (5)			Methane	FLARE IS CONTROL	25	LB/H		109.45	T/YR				0
OH-0330	RUMPKS SANITARY LANDFILL	OH	12/23/2008	OPEN FLARE			Methane	FLARE IS CONTROL	25	LB/H		109.45	T/YR				0

ExxonMobil Chemical Company
 Baytown Olefins Plant
 Fugitives - 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	Limit	Unit	Limit	Unit
*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	