

Exhibit 4

ExxonMobil Chemical Company

5000 Bayway Drive
P.O. Box 4004
Baytown, Texas 77522-4004



October 16, 2012

Mr. Carl Edlund, P.E.
Multimedia Planning and Permitting Division
United States Environmental Protection Agency Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

**Response to June 29, 2012
Completeness Determination Letter
Baytown Olefins Plant
Ethylene Expansion Unit**

Dear Mr. Edlund:

ExxonMobil Chemical Company (ExxonMobil) is hereby submitting this letter in response to your request received June 29, 2012 for additional information related to the application for a greenhouse gas permit for an ethylene expansion unit to be located at ExxonMobil's Baytown Olefins Plant (BOP) in Baytown, Harris County, Texas.

Per your request, ExxonMobil understands that you need additional information to complete your review. The response to each of your requests is provided in the attachments. The USEPA items/questions contained in the request are presented below followed by ExxonMobil's responses in *italics*.

If you have any questions about the information provided, please contact me at benjamin.m.hurst@exxonmobil.com or (281) 834-6110.

Sincerely,

ExxonMobil Chemical Company

A handwritten signature in blue ink that reads "Benjamin M. Hurst".

Benjamin M. Hurst
Air Advisor

Enclosures

cc: Manager, TCEQ Region 12 Air Program, Houston
Randy Parmley, P.E., Sage Environmental Consulting, L.P

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ENCLOSURE

ExxonMobil Response to EPA Completeness Comments Application for Greenhouse Gas Prevention of Significant Deterioration Permit ExxonMobil Chemical Company – Baytown Olefins Plant (BOP)

Process Description

1. On page 2-1, the permit application indicates 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. The application also states that the composition of the blended fuel gas will vary and will depend on current hydrogen production and disposition. The permit application states the use of natural gas as the primary fuel for lowering the GHG emissions. Please provide additional technical information explaining why natural gas would be considered over fuel gas containing hydrogen (H₂). Provide all relevant factors including economics and energy impacts. Please provide additional information pertaining to the use of H₂ as a secondary fuel gas to the furnace. What circumstances will allow or disallow hydrogen to be used as either a primary in lieu of natural gas or as a secondary fuel?

Response:

Hydrogen is a valuable by-product of the ethane cracking process. It is generated through the recovery section as a relatively high purity stream, estimated at an average concentration of 74 mol%. The hydrogen is concentrated in the Tail Gas stream, which requires additional processing to recover the hydrogen for commercial use. Several dispositions for the recovered hydrogen exist because BOP is located in an industrial area within a large integrated site. At this time, the proposed project plans to blend the Tail Gas into the fuel gas system with natural gas to meet heating value requirements.

The GHG calculations contained in the permit application received by USEPA on May 22, 2012 were based on the highest emission scenario, which is firing fuel gas consisting of pipeline quality natural gas. The calculation methodology has been revised to account for a start-up operating scenario where the furnace section is fired solely on natural gas due to the unavailability of the hydrogen-rich stream and a routine operating scenario consisting of blending the hydrogen-rich stream into the fuel gas system. These two streams are referred to as Pipeline Quality Natural Gas (for start-up operation) and Blended Fuel Gas (routine operation). The GHG emission calculations have been revised to reflect the two estimated firing scenarios of blending the hydrogen-rich stream into the fuel gas system on a routine basis and firing solely natural gas for start-up scenarios. Refer to Attachment 1 to this letter for the updated Table 3-1 Emission Point Summary, revised calculations for fuel

compositions and revised emission calculations for the furnaces and decoking drum. Note that this change to the routine fuel gas composition has resulted in a net decrease of 1,344,808 tons of CO₂e per year for the furnace section.

2. Please supplement the process flow diagram by identifying all emission control points for GHG emissions, include the emission control point identification numbers.

Response:

See Attachment 2 to this letter for the revised process flow diagram that includes emission control points.

3. On pages 2-3 and 2-4 of the permit application, it states that “no increase in GHG emissions are being requested” for the changes proposed at the Acetylene Converter Regeneration Vent, Cooling Tower, Wastewater Collection and Treatment System and Storage tanks. Please provide the PSD applicability calculations for these units to support the “no increase” in GHG emissions request.

Response:

PSD applicability calculations have been supplied for the cooling tower and storage tanks to demonstrate no increase in GHG emissions. The wastewater collection and treatment system (EPN: BIOX) is no longer included in the scope of proposed project; therefore this EPN has been removed from Table 3-1 Emission Point Summary. Refer to Attachment 1 to this letter for emission calculations for the proposed sources that do not have GHG emissions and a revised Table 3-1 Emission Point Summary.

Acetylene Converter Regeneration Vent

As described in the application received May 22, 2012, the Deethanizer overhead stream is sent to the Acetylene Converters where acetylene is converted to ethylene and ethane. Upon further detailed design, it was determined that the acetylene converters will require online regeneration and will therefore generate GHG emissions periodically when the catalyst is regenerated by oxidizing coke that has accumulated on its surface. The GHG emissions, consisting of CO₂ and trace amounts of N₂O and CH₄, are vented to the atmosphere through the Acetylene Converter Regeneration Vent (EPN: ACETCONVXX).

Emissions Calculations

CO₂ emissions generated from regeneration of acetylene converter catalyst are calculated by estimating the total amount of coke generated annually and then applying a conservative assumption that all of the coke contains carbon, i.e., 100% of the coke is oxidized to CO₂.

CH₄ and N₂O emissions from the catalyst regeneration were based on the calculations for catalytic reforming units contained in 40 CFR 98 Subpart Y since this is the emission source most similar to the acetylene converter regeneration vent. The CH₄ and N₂O emissions were

calculated by Equation Y-9 and Y-10, respectively for CH₄ and N₂O, using the emission factors for coal and coke from 40 CFR 98 Subpart C Table C-2 and the CO₂ emission factor for petroleum coke from 40 CFR 98 Subpart C Table C-1.

The GWP values in Table A-1 of the GHG MRR Rule (40 CFR Part 98, Subpart A) 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.

Detailed calculations for the acetylene converter regeneration vent are contained in Attachment 1 to this letter. The proposed allowable emissions of CO₂, CH₄, N₂O, and CO₂e for the acetylene converter regeneration vent associated with the proposed project are presented in the updated Table 3-1 Emission Point Summary located in Attachment 1 to this letter.

BACT Analysis

The purpose of the acetylene converter is to partially hydrogenate acetylene to produce ethylene. This reaction deposits hydrocarbon, commonly referred to as "green oil", which forms coke on the surface of the catalyst and must be periodically regenerated through oxidation. This process results in an exhaust stream consisting of typical combustion products that is vented to the atmosphere through the acetylene converter regeneration vent. The estimate of annual coke formation is based on process knowledge and experience. The CO₂e emitted from the acetylene converter regeneration vent is estimated to be 0.04% of the total GHG emissions for the proposed project and CO₂ emissions account for over 99% of the total CO₂e emissions from this emission source. This GHG BACT analysis is therefore focused on controlling CO₂ emissions.

Step 1 – Identify Potential Control Technologies

The following technologies were identified as potential control options for the acetylene converter regeneration vent based on available information and data sources:

- **Good combustion practices**
 - The RACT/BACT/LAER Clearinghouse (RBLC) was searched for control technologies that are applicable to the acetylene converter regeneration vent or similar sources. One entry was found for a catalyst regenerator vent located at the BASF Fina NAFTA Region Olefins Complex, which is described as an acetylene converter regeneration vent. This entry lists good combustion practices as the selected control technology for CO₂ emissions.
- **Minimizing coke formation**
 - Coke formation is minimized by limiting the amount of green oil that is formed in the acetylene converter.
- **Carbon Capture and Sequestration (CCS)**
 - Refer to the response to Item 7 for a detailed description of CCS.

There was no other identified control technology for this emission source or similar emission sources, based on available information and data sources, such as "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry" published by USEPA Office of Air and Radiation.

Step 2 - Eliminate Technically Infeasible Options

Good combustion practices are not an applicable control technology for the acetylene converter regeneration vent since it is not a stationary combustion source, nor during the regeneration of the catalyst does it function as a stationary combustion source. Fuel is not combusted during the regeneration of catalyst, therefore this equivalency is not valid and good combustion practices as a control technology is eliminated as technically infeasible.

Coke formation can be minimized by limiting green oil formation, which is achieved by maintaining a molar ratio of hydrogen to acetylene above 0.9 mole of hydrogen per mole of acetylene during normal operation of the acetylene converters. Minimizing coke formation is considered technically feasible for the proposed project.

As discussed in the response to Item 7, CCS is considered technically, environmentally, and economically infeasible for the pyrolysis furnaces, which have CO₂ emissions almost three thousand times greater than the proposed regeneration vent. CCS is eliminated as a potential control technology for GHG emissions.

Step 3 - Rank Remaining Control Technologies

There is one remaining control technology feasible control technology, therefore ranking is not applicable.

Step 4 - Evaluate the Most Effective Controls and Document Results

Step 4 is not applicable since there is one available control technology.

Step 5 - Selection of BACT

As a result of this analysis, minimizing coke formation by limiting green oil formation is selected as BACT for the proposed acetylene converter regeneration vent. The following BACT limits are proposed to ensure BACT is met:

- 1. Maintain a molar ratio above 0.9 mole of hydrogen per mole of acetylene during periods of normal operation, excluding start-up and shutdown, of the acetylene converters on a 365-day rolling average basis.*
- 2. Calculate as a daily average the molar ratio of hydrogen to acetylene based on online analyzer analysis of the feed streams to the acetylene converters during periods of normal operation, excluding start-up and shutdown.*

Train 5 Duct Burners

Additionally, as part of further detailed project design, a more efficient method of incremental steam generation was identified. Duct burners will be added to the heat recovery steam generator section of the gas turbine generator train 5 (Train 5) to provide supplemental heat to the turbine exhaust stream, thereby generating incremental steam for use at BOP. Train 5 (EPN: HRSG05) is located in the base plant at BOP and is equipped with a SCR for NO_x emission control. The heat recovery steam generation (HRSG) section's function is to generate steam by recovering heat contained in the exhaust gas stream of the gas turbine generator. The duct burners are configured in rows and will be fired at their design firing rate to create additional steam from natural gas firing. There will be no increase in the firing of the gas turbine generator section of Train 5 due to the installation of the duct burners.

Emissions Calculations

CO₂ emissions generated from firing the duct burners are calculated using Equation C-5 from the Federal Greenhouse Gas Mandatory Reporting Rule (GHGMRR), 40 CFR 98 Subpart C - General Stationary Fuel Combustion Sources, the natural gas annual estimated usage rate assuming 8,760 hours of operation, and the annual average carbon content of pipeline quality natural gas.

CH₄ and N₂O emissions from the duct burners were calculated using Equation C-8 from the 40 CFR 98 Subpart C. The GWP values in Table A-1 of the GHG MRR Rule (40 CFR Part 98, Subpart A) 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.

Detailed calculations for this determination are contained in Attachment 1 to this letter. The proposed allowable emissions of CO₂, CH₄, N₂O, and CO₂e for the duct burners associated with the proposed project are presented in the updated Table 3-1 Emission Point Summary located in Attachment 1 to this letter.

BACT Analysis

The purpose of the duct burners is to generate incremental steam during times when the steam cracking furnaces are unable to meet the steam demand. Similar to the furnaces, the duct burners will emit CH₄, CO₂, and N₂O. In addition, the CO₂ emissions account for 99% of the CO₂e emissions from this source and so the following GHG BACT analysis is focused on CO₂.

Step 1 – Identify Potential Control Technologies

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

- *Use of low carbon fuel*

- Fuels containing lower concentrations of carbon generate less CO₂ emissions than higher carbon fuels.
- Use of good operating and maintenance practices
 - Periodic Tune-up – The burner tips are cleaned as needed and preventative maintenance checks are performed on the fuel flow meters.
 - Maintain complete combustion – CO concentrations are continuously monitored by an online analyzer to ensure complete combustion.
 - Oxygen Trim Control – Monitoring of oxygen concentration in the flue gas is conducted, and the inlet air flow is adjusted to maximize thermal efficiency.
- Energy Efficient Design
 - Use of an Economizer – Use of a heat exchanger to recover heat from the exhaust gas to preheat incoming HRSG Section boiler feedwater to attain thermal efficiency.
 - HRSG Section Blowdown Heat Recovery – Use of a heat exchanger to recover heat from HRSG Section blowdown to preheat feedwater results in an increase in thermal efficiency.
 - Condensate Recovery – Return of hot condensate for use as feedwater to the HRSG Section. Use of hot condensate as feedwater results in less heat required to produce steam in the HRSG, thus improving thermal efficiency.
- Carbon Capture and Sequestration (CCS).
 - Refer to the response to Item 7 for a detailed description of CCS.

Step 2 - Eliminate Technically Infeasible Options

As discussed in the response to Item 7, CCS is considered technically, environmentally, and economically infeasible for the steam cracking furnaces, which have CO₂ emissions two-and-a-half times greater than the proposed duct burners. CCS is eliminated as a potential control technology for GHG.

Use of a low carbon fuel is technically feasible. Pipeline quality natural gas is the lowest carbon fuel commercially available at BOP.

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

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

Step 3 - Rank Remaining Control Technologies

Natural gas is among the lowest-carbon fuels commercially available. As contained in 40 CFR 98, Subpart C, Table C-1, there are 56 other fuels with larger CO₂ emission factors

than the factors for natural gas. Natural gas is the only commercially available fuel source at BOP and is a low carbon fuel.

The remaining technology not already included in the existing HRSG configuration is periodic tune-up of burners and is ranked below use of low carbon fuels due to the inability to quantify its GHG emission reduction.

Step 4 - Evaluate the Most Effective Controls and Document Results

Currently, periodic cleaning of burners and preventative maintenance checks of fuel flow meters are performed as needed at similar sources across BOP. The effectiveness of this control option cannot be directly quantified. The most effective control technology for reducing GHG emissions is therefore combusting a low carbon fuel.

Step 5 - Selection of BACT

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

- Use a low carbon fuel
 - Consume pipeline quality natural gas, or a fuel with a lower carbon content than pipeline quality natural gas, as fuel to the duct burners.
- Good operating and maintenance practices
 - Maintain CO concentrations at or below 7.4 ppmvd corrected for 15% oxygen on a 12-month rolling average for HRSG05, which ensures complete combustion.
 - Perform and maintain records of online burner inspections when indicated by CO levels >100 ppmvd @ 15% oxygen for a one-hour average and during planned shutdowns.
 - Perform cleanings of the duct burner tips as-needed to maintain thermal efficiency.
 - Calibrate and perform preventative maintenance checks of the continuous CO stack monitors per 40 CFR 60 Appendix B4 every quarter.
 - Calibrate and perform preventive maintenance on the duct burners' fuel flow meters annually.
- Energy efficient design
 - Maintain operation of the existing condensate recovery, HRSG Section blowdown heat recovery, and economizer.
 - Demonstrate operational BACT for the duct burners by calculating the thermal efficiency of HRSG05 monthly and maintaining a thermal efficiency of no less than 70% on a 12-month rolling average basis. Efficiency will be demonstrated by the following equation:

$$\text{Unit Efficiency} = \frac{\text{Heat Content of Steam Produced} + \text{Heat Content of Power Produced}}{\text{Heat Content of Fuel Supply}} * 100$$

The proposed minimum 70% thermal efficiency BACT limit is based on historical operational data of Train 5 and includes projected performance with the duct burners as shown in the following equation. Note that this value is 10% higher than a limit granted to a similar emission source¹.

$$\text{Minimum Unit Efficiency} = \frac{\text{Minimum Heat Content of Steam Produced} + \text{Minimum Heat Content of Power Produced}}{\text{Maximum Heat Content of Natural Gas Supplied} + \text{Maximum Heat Content of 50\# Steam Supplied} + \text{Maximum Heat Content of Water Supplied}} * 100$$

$$\text{Minimum Unit Efficiency} = \frac{706 \text{ MMBtu/hr} + 543 \text{ MMBtu/hr}}{1649 \text{ MMBtu/hr} + 5 \text{ MMBtu/hr} + 130 \text{ MMBtu/hr}} * 100 = 70\%$$

- CO₂e emissions from the duct burners will be determined based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance.
- Determine 12-month rolling average firing rates of the duct burners and recorded monthly.

Refer to Attachment 4 to this letter for a summary of the proposed work practice standards and operating limits for the duct burners.

4. Please provide supplemental technical data that discusses the design and operation of the new staged flare system, i.e., percent combustion efficiency, percent emission reduction, proposed monitoring and recordkeeping strategy, maintenance schedule, etc. Will it be computer controlled? If so, will there be manual overrides? Please provide benchmark comparison data of new flare system to similar or existing sources. Was a flare gas recovery system considered for the proposed project? Please supplement the BACT analysis to support its elimination.

Response:

The "staged flare" described in the permit application will consist of a steam-assisted elevated flare and a multi-point ground flare system, such as John Zink Company's LRGO multi-point flare system, or one that is comparable. The elevated flare will control routine continuous operation vents, while the multi-point ground flare system will control routine intermittent operation vents. The flare system is described as "staged" because it is designed to segregate the continuous flows from the intermittent flows, thereby ensuring the streams are mitigated appropriately and per design to achieve stated destruction and removal efficiencies (DRE) and achieve the estimated emission rates. This staged flare

¹ See BASF Fina Petrochemicals L.P., Port Arthur, TX, GHG PSD Final Permit issued by USEPA Region 6 on August 24, 2012.

system can be alternatively described as a prioritized flare system due to the segregation of streams based on the stream characteristics. The staged flare system will achieve better than federal BACT performance when operated per design, thereby exceeding current flare installations that simply meet federal BACT. A detailed description of each flare, as well as the operation of the flare system, is contained in the following paragraphs.

Elevated Flare

The steam-assisted elevated flare (EPN: FLAREXX1) is currently estimated to have a height of up to 270 feet. It will be designed to achieve a DRE of 99% for hydrocarbons with three or less carbon atoms and 98% for hydrocarbons with more than three carbon atoms with smokeless operation, however, for the purposes of estimating GHG emissions, an assumed flare combustion efficiency of 98% was applied since the total carbon content was the basis for emissions estimating, which does not segregate hydrocarbons.

The design of the elevated flare will be completed by an industry leader in flare technology and will incorporate industry-leading technology, including online flow and composition measurement and computer control of the steam flow to control the combustion zone heating value through stream to hydrocarbon ratio control. A dual-range flow measurement system will also be installed on the header to the elevated flare. The pilots will be fired by natural gas and will be continuously monitored for presence of flame.

Multi-Point Ground Flare

The multi-point ground flare system (EPN: FLAREXX2) has a principle application to the petroleum refining and chemical processing industries due to its internal staging system that ensures short, smokeless flames maintained over the full operating range of the flare since burners are sequentially opened to maintain control. John Zink Company performed testing on the LRGO burner design and submitted the data and results to USEPA². The LRGO burner demonstrated 99.82% combustion efficiency when combusting a crude propylene stream. The composition of the proposed stream routed to the proposed multi-point ground flare system is comparable to the crude propylene used in the John Zink test. The intermittent stream contains highly combustible components such as butane, butene, ethylene, methane, and hydrogen, resulting in a typical heating value of in excess of 1,000 BTU per standard cubic foot (Btu/scf) of off gas. In addition to previously submitted test data, the following has been provided by John Zink³,

“John Zink confirms our performance guarantee of the proposed ground flare burners as follows. We guarantee the destruction efficiency to be 99.8% or greater in the following range of operation:

- *Burner operating pressure > 4 psig and*
- *Flare gas net heating value > 1000 BTU/SCF.”*

² See Attachment 3 to this letter for John Zink submittal to USEPA with supporting data.

³ Per correspondence between Mr. Kevin Leary, John Zink and Mr. Alope Sarkar, ExxonMobil on October 7, 2012.

The operation of the multi-point ground flare system will be designed to meet the above requirements. Use of staging valves in this multi-header design allows the required minimum pressure of 4 psig to be maintained while the multi-point ground flare is operated. Most waste gas streams that will be routed to the multi-point ground flare will consistently have a net heating value in excess of 1,000 Btu/scf, but there may be a few instances where the waste gas will contain appreciable quantities of hydrogen. It is widely known that hydrogen contributes to good combustion more than its volumetric heating value of 274 Btu/scf would imply. Most notably, hydrogen contributes to good combustion as a result of a high flame speed. In an effort to address this consideration, an adjustment to the volumetric heating value of hydrogen has been made when calculating the net heating value of waste gas streams routed to flares. This "net heating value of hydrogen as adjusted"⁴ is 1,212 Btu/scf and more accurately reflects the realized contribution hydrogen makes to the good combustion of waste gas streams routed to flares.

Incorporating this adjusted net heating value for hydrogen results in all proposed waste gas streams routed to the multi-point ground flare exceeding the minimum net heating value of 1,000 Btu/scf. Correspondence with John Zink Company demonstrates they are in agreement with this approach of adjusting net heating value for hydrogen since combusting streams with higher hydrogen content "should improve overall DRE"⁵.

The proposed multi-point ground flare system uses an array of high pressure burners to produce short, highly efficient flames. Pressure assisted burners utilize the flare gas pressure to ensure high exit velocity at the burner exit. The high velocity produces the energy required to promote high air entrainment and mixing in the combustion zone. This entrainment / mixing energy in the combustion zone is the key to producing an efficient, smokeless flame. This energy level is created by a high velocity discharge without requiring supplemental energy such as steam or forced air blowers. The philosophy of the control system provides that when gas (energy) flow is low, the number of burners is reduced in order that there is sufficient fuel supply to each burner to maintain the required energy level for clean burning.

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

⁴ The most recent example of this adjustment to the net heating value of hydrogen is contained in the United States of America v. Marathon Petroleum Company LP and Cattlesburg Refining, LLC Consent Decree signed April 5, 2012. The "net heating value of hydrogen as adjusted" discussion is contained in Section III Definitions and Appendix 1.3; <http://www.epa.gov/compliance/resources/decrees/civil/caa/marathonrefining-cd.pdf>.

⁵ Per correspondence between Mr. Kevin Leary, John Zink and Mr. Alope Sarkar, ExxonMobil, on October 7, 2012.

For the purposes of estimating GHG emissions, an assumed flare combustion efficiency of 99.8% was applied since the pressure-assisted flare design has demonstrated this efficiency when the total heating value of the flare stream is greater than 1,000 Btu/scf. The current multi-point ground flare design contains up to 12 runners and will contain pilots on each runner that will fire pipeline quality natural gas and/or ethane. A dual-range flow measurement system will be installed on the header to the multi-point ground flare. The pilots will be continuously monitored for presence of flame. The emissions calculations for the multi-point ground flare i.e., FLAREXX2 Intermittent Flaring and FLAREXX2 Pilot Gas are contained in Attachment 1 to this letter.

Staged Flare System Monitoring and Operation

ExxonMobil proposes to install and operate a staged flare system per the manufacturer's specifications that will achieve the requested DREs. ExxonMobil proposes to monitor and record the following parameters to demonstrate continuous compliance with staged flare system operating specifications required to achieve the stated DREs:

- 1. Continuously monitor and record the pressure of the flare system header,*
- 2. Continuously monitor and record the flow to the elevated flare through a flow monitoring system,*
- 3. Continuously monitor the steam flow to the elevated flare through a flow monitoring system and record the steam to hydrocarbon ratio,*
- 4. Continuously monitor the composition of the waste gas contained in the flare system header through an online analyzer located on the common flare header, sufficiently upstream of the diverting headers to the elevated flare and the multi-point ground flare, and record the heating value of the flare system header,*
- 5. Continuously monitor the flow rate to the multi-point ground flare to demonstrate that flow routed to the multi-point ground flare system exceeds 4 psig; however, if a lower pressure can be demonstrated to achieve the same level of combustion efficiency, then this lower limit will be implemented,*
- 6. Maintain a minimum heating value and maximum exit velocity that meets 40 CFR § 60.18 requirements for the routine streams routed to the elevated flare including the assist gas flow, and*
- 7. Monitor and maintain a minimum heating value of 1,000 Btu/scf of the waste gas (adjusted for hydrogen) routed to the multi-point ground flare system to ensure the intermittent stream is combustible; however, if a lower heating value limit can be demonstrated to achieve the same level of combustion efficiency, then this lower limit will be implemented.*

All computer-controlled systems contain manual overrides, however, this flare system will be designed to be computer controlled at all times due to its complexity. This includes operation of the elevated flare and its assist steam flow and operation of the multi-point

ground flare. Manual overrides would be utilized only in the event of a failure of the computer control system to function properly. Refer to Attachment 1 to this letter for revised flare emission calculations and revised Table 3-1 Emission Point Summary. Refer to Attachment 4 to this letter for a summary of the proposed work practice standards and operating limits for the staged flare system.

Flare Gas Recovery

Flare gas recovery was evaluated by ExxonMobil for the proposed project. A compression system was specified with a total capacity to recover up to 4,000 pounds per hour of flare gas. This flow rate is based on the estimated average routine flow rate to the elevated flare. Since flare gas recovery is technically feasible, an economic analysis was performed to evaluate the economic feasibility of this control technology. Table 1 summarizes the economic analysis of flare gas recovery for the proposed project, which is estimated to avoid 30,612 tons of CO_{2e} per year. As shown in the table, flare gas recovery is estimated at a cost of \$134.2 per ton of CO_{2e} avoided, which is an excessive cost to mitigate GHG emissions and renders flare gas recovery an economically infeasible control technology. Therefore, it is eliminated from consideration as a control technology for flare GHG emissions.

Table 1. Economic Analysis for Flare Gas Recovery

Item	Units	Value⁶	Comments
Flare Gas Recovery System Cost			
Capital Cost of FGR	\$ (millions)	20.0	Site-specific design
Amortized Capital Cost	\$ (millions)	3.9 ⁷	See Note
Operating and Maintenance Expenses	\$ (millions)	0.2	Site-specific design incorporating natural gas consumption reduction
Total Annualized FGR Cost	\$ (millions) / yr	4.1	
Flare Gas Recovered			
Total Flare Gas Recovered	MMscf/yr	574.3	Estimated recovered flare gas
	MMBtu/yr	505,990	Higher heating value of 881.1 Btu/scf
Economics of Avoided CO_{2e}			
Annual Emissions from Flaring Flare Gas	tons CO _{2e} / yr	29,695	Flaring emissions from unrecovered flare gas
Annual Emissions from Firing Natural Gas	tons CO _{2e} / yr	29,568	Firing natural gas at the furnaces
Annual Emissions from Firing Flare Gas	tons CO _{2e} / yr	28,651	Firing recovered flare gas at the furnaces
Tons of CO_{2e} Avoided	tpy	30,612⁸	
Cost per ton of CO_{2e} Avoided	\$/ton CO_{2e}	134.20	

⁶ All monetary estimations have been calculated in 2016 dollars.

⁷ A capital charge rate of 19% was assumed with an expected equipment life of 20 years.

⁸ Tons of CO_{2e} avoided = Annual Emissions from Flaring Flare Gas + Annual Emissions from Firing Natural Gas - Annual Emissions from Firing Flare Gas = 29,695 tpy + 29,568 tpy - 28,651 tpy = 30,612 tpy

5. On page 4-3, the permit application states “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... Examples of good operating and maintenance practices include good air/fuel mixing in the combustion zone; sufficient residence time to completed 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.
- A. Please provide comparative benchmark data on the percent efficiency of the burners compared to existing or similar sources. Please provide details concerning the preventative maintenance on burners, frequency and recordkeeping. How often will burners be inspected? How will this be ensured? What recordkeeping requirements are you proposing? What will alert on-site personnel to problems?

Response:

Benchmark data on the percent efficiency of the burners is not readily available since percent efficiency is not a relevant or applicable performance metric to pyrolysis furnace burners. The combustion products resulting from combustion of fuel gas in burners is CO₂ and CO, where CO₂ represents full combustion and CO represents incomplete combustion of the fuel gas. Pyrolysis furnace burners are designed to achieve complete combustion, thereby converting all of the energy contained in the fuel to heat for the furnace. Combustion performance is indicated by the levels of CO present in the furnace stack gas and can therefore be directly measured with an online analyzer. Monitoring and maintaining annual average CO emissions below 50 ppmv corrected for 3% oxygen is common across industry to demonstrate good combustion and is an established BACT for pyrolysis furnaces in Region 6.

Achieving good combustion performance as demonstrated by maintaining CO levels below 50 ppmv corrected for 3% oxygen annually is a result of good burner design employing good operating and maintenance practices. Good design principles and operating and maintenance practices proposed for this project include:

- ExxonMobil proprietary burner technology uses air/fuel pre-mixing to maximize burner stability and performance over a large operating window of fuel gas pressure and composition. The burners for the proposed project will be designed and shop-tested to accommodate the fuel gas composition range and optimize the burner performance for the design operating window.*
- ExxonMobil proprietary burner technology uses air staging and integral flue gas recirculation to minimize NO_x emissions without compromising the burner stability and performance. Typical staged fuel low-NO_x burners use small diameter fuel gas injection holes that are prone to plugging and require diligent inspection programs, while staged air burners are intrinsically safer and more robust. A regular inspection program is not required since impaired*

performance will result in incomplete combustion, which will be measured by the CO analyzer and detected by operations personnel for troubleshooting.

- *The project will install a knock-out drum to protect the burners against liquid carry over in the fuel gas to the furnaces. This will mitigate the risk of burner fouling or damage, which reduces combustion efficiency resulting in increased CO emissions.*

As discussed above, the new furnaces will be equipped with a CO analyzer at the stack to monitor combustion. The production of CO is a reliable indicator of incomplete combustion requiring corrective actions. ExxonMobil proposes a limit of not more than 50 ppmv CO corrected for 3% oxygen on a 12-month rolling average basis. CO levels above 100 ppmv corrected for 3% oxygen on a one-hour average trigger an alarm to the Operations Board Operator and troubleshooting efforts by the Operation personnel to identify and correct the issue. If CO emissions cannot be minimized via simple troubleshooting, flame pattern visualization techniques are employed to identify any "malfunctioning" burner(s) due to fouling or damage with assistance of the Technical Department. If necessary, a "malfunctioning" burner will be switched-off and tagged in the field until the next opportunistic maintenance down time if it cannot be repaired while the furnace is on-line. A record will be maintained for any maintenance activity completed on the burner.

Since CO is a direct indicator for good combustion, and since good combustion can only be achieved through good operating and maintenance practices, ExxonMobil proposes to calculate the CO concentration monthly and record the 12-month rolling average to establish an enforceable BACT limit supported by recordkeeping requirements. Through continuous operation below the BACT limit of 50 ppmv CO corrected for 3% oxygen on a 12-month rolling average, the proposed project will ensure good combustion at the furnace burners.

Refer to Attachment 4 to this letter for a summary of the proposed work practice standards and operating limits for the furnace section.

- B. What will be the operating parameters that will ensure minimum excess air? Please include a discussion on how O₂ analyzers will be utilized to determine optimum excess air to provide proper combustion.

Response:

Complete combustion can be commercially achieved at low excess oxygen levels as measured by online analyzers during normal operation, which results in high furnace thermal efficiency and low GHG emissions. The excess oxygen at the burners is controlled and minimized via an application resetting the flue gas draft at the furnace bridge wall during normal operation. This application minimizes excess air to the extent complete combustion and maximum thermal efficiency is achieved. Excess oxygen is increased until CO decreases to maintain complete combustion.

A low excess oxygen alarm in the DCS mitigates the risk of incomplete combustion due to lack of air. This alarm alerts the Operator that minimum excess oxygen has been detected so he/she may monitor the application controlling excess oxygen and correct the situation manually, only if necessary.

There may be times when the furnace will operate at higher excess oxygen than the minimum required level to achieve complete combustion. These times may include but are not limited to:

- *Furnace turndown to avoid dew point acid corrosion in the top process rows.*
- *Increased super high pressure (SHP) steam production to optimize the overall plant efficiency and*
- *Natural furnace penetrations that leak and allow air to ingress, but do not contribute to complete combustion.*

As discussed above, adherence to a limit of 50 ppmv CO corrected for 3% oxygen on a 12-month rolling basis is the appropriate surrogate to indicate good combustion since excess oxygen is optimized based on the CO measurement. At the same time, adherence to an exhaust stack temperature limit of 325°F on a 12-month rolling basis ensures thermally efficient operation (see response to Item 6). These limits together ensure the furnace is operated with complete combustion without compromising thermally efficient operation.

- C. Please provide further discussion as to how good combustion efficiency will be ascertained for the furnace's operating parameters pertaining to feedstock/steam ratios, temperatures, pressures, and residence times. What is ExxonMobil's preferred monitoring method, recordkeeping requirements for the cracking furnaces (e.g., continuous or periodic)?

Response:

As stated in the responses to Items 5.A. and 5.B., good combustion efficiency is determined by the extent to which combustion is complete, and is therefore appropriately measured by CO levels in the furnace exhaust. Feedstock/steam ratios, temperatures, pressures, and residence times may be appropriate for other combustion units, but have little relevance in determining good combustion efficiency for pyrolysis furnaces.

ExxonMobil proposes to calculate the CO concentration monthly and record the 12-month rolling average to establish an enforceable BACT limit supported by recordkeeping requirements. Through continuous operation below the BACT limit of 50 ppmv CO corrected for 3% oxygen on a 12-month rolling average, the proposed project will ensure good combustion at the furnace burners.

- D. Please submit a detailed description of the anticipated procedures that are proposed as part of the maintenance practices and include a proposed schedule for planned maintenance.

Response:

ExxonMobil's proprietary technology for the pyrolysis furnaces and burners is designed such that routine maintenance is not required and inspection activities are limited to opportunity inspections during unit shutdowns or during troubleshooting efforts. It is common for other pyrolysis furnace designs (non-ExxonMobil proprietary technology) to require annual cleaning of burners since they use small diameter fuel gas injection holes that are prone to plugging and require diligent inspection programs.

Operation and maintenance of the burners will be consistent with the current Baytown Olefins Plant practices. Burner inspection and maintenance is typically performed on a planned basis during radiant re-tubes or other extended furnace down times requiring a furnace entry, which may be on a frequency of 5-10 years depending upon furnace performance (such as CO concentrations and exhaust stack temperature). Inspection records are kept in the furnace monitoring filing system. Key inspection steps include:

- *Check integrity of burner components (tips, tiles, surrounds),*
- *Inspect burner spuds for potential fouling,*
- *Inspect burner air doors and lubrication, and*
- *Inspect all burners before closing main door to check for potential debris.*

6. It is indicated in the "Energy Efficient Design" section that "the proposed project will use a proprietary furnace design to minimize its carbon footprint...To maximize thermal efficiency 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."

- A. Please provide benchmarking data that compares the technologies outline in this section to other existing or similar sources, i.e., the percent energy efficiency and CO₂ control effectiveness of the economizer, steam generation from process waste heat, feed preheat and minimize hydrocarbon ratio.

Response:

The new furnaces will be designed to maximize thermal efficiency during normal operation as part of the business model for the proposed project. The design stack temperature was selected to maximize heat recovery while avoiding dew point acid corrosion in the top process rows at low rates. The design specification will include details such as the use of seal bags at each furnace penetration to limit air ingress over the life of the furnace. It will also specify the insulation to minimize casing heat losses.

The new furnaces will generate super high pressure (SHP) steam to maximize the site energy integration and have a broad operating window for the site overall energy optimization. The excess oxygen at the burners is controlled (minimized) via an application resetting the flue gas draft at the furnace bridge wall during normal operation. See the response to Item 5.B. for a description of how the excess oxygen is measured. This ensures continuous thermal efficiency optimization when the furnace is on-line.

Benchmarking the proposed pyrolysis furnaces to existing or similar sources is not particularly useful if the objective is to determine the extent of energy efficiency. The technologies outlined in the energy efficient design section for the proposed pyrolysis furnaces do not fundamentally differ from other pyrolysis furnaces. Pyrolysis furnaces input large amounts of heat to crack ethane, and this heat is supplied through the combustion of fuel gas, but not all of the heat can be input into the ethane, therefore a fundamental component of these furnaces are the mechanisms to recover that unutilized heat through the use of economizers and other heat recovery systems. It would not be profitable to operate a pyrolysis furnace without heat recovery, and therefore, heat recovery is an element of any existing or similar sources. What is notable is that, at the time of submittal of this response letter, two final permits have been issued by Region 6 for facilities containing new pyrolysis furnaces. These facilities described pyrolysis furnaces containing the same fundamental equipment as the proposed furnaces, with energy efficiency targets (as demonstrated through a maximum exhaust stack temperature) within 31 degrees Fahrenheit of each other. The proposed project intends to operate with an exhaust stack temperature at or below 325°F during on-line operation (furnace producing ethylene) on a 365-day rolling average. This value falls within the range of the aforementioned recent GHG permit limits (309-340°F).

- B. What operating parameters does ExxonMobil prefer to monitor to determine that the thermal efficiency in the plant is optimized, i.e., stack temperature, pressure, fuel combusted per product produced, etc.?

Response:

ExxonMobil proposes using a continuously monitored furnace stack temperature as a metric for energy efficiency. The proposed limit is 325°F during on-line operation (furnace producing ethylene) on a 365-day rolling average basis. This definition excludes decoking operations, start-ups and shutdowns. This value accounts for the broad operating window required for the overall plant energy optimization, some allowance for commercial application, and moderate convection section fouling. Some fouling of the convection section flue gas side is expected over the life of the equipment. Fouling is due to ambient particulates and insulation materials partially covering the convection section fins and reducing the heat transfer capability.

This value falls within the range of two recent GHG final permits (309-340°F) as discussed in the response to Item 6A. Refer to Attachment 4 to this letter for a

summary of the proposed work practice standards and operating limits for the furnace section.

- C. Provide any supporting data to substantiate operating and design improvements to the proposed technologies compared to the past operation and design, e.g., past energy consumed per ton of product and what will be the difference compared to the new construction, comparative benchmark studies to similar operations. Please include any technical data that supports your conclusions, as well as the associated decrease in GHG per pound of product.

Response:

Pyrolysis furnace technology has long been a mature technology. Pyrolysis furnaces perform at the highest efficiency levels upon initial start-up because of new burners, new convection tubes, sealed firebox, sealed stack, etc. Over time through the natural course of operation, the convection section tubes will collect debris and furnace penetrations will leak and allow air to ingress. Each of these contributes to operating towards the bottom of the normal energy efficiency operating envelope.

However, if the furnaces are to maintain an exhaust stack temperature at or below 325°F on a 365-day rolling average during online operation, then measures will have to be employed to periodically wash the convection section and maintain the seal bags to manage air ingress. Therefore, the furnaces will be designed to allow for these types of maintenance activities. For example, convection section access has been integrated into the design of the proposed furnaces to permit for convection section washing every few years, if needed, to maintain energy efficiency. This design capability will be incorporated into the proposed furnaces, along with good operating and maintenance practices, will allow for these pyrolysis furnaces to maintain operation below their energy efficiency target, i.e., 325°F, over long periods of time.

7. On page 4-8 of the permit application, the cost estimates provided for the Carbon Capture and Storage (CCS) appear to solely rely on the August 2010 report entitled, "Report of the Interagency Task Force on Carbon Capture and Storage." BACT is a case-by-case determination. Please provide site-specific facility data to evaluate the eliminate CCS from consideration. This material should contain detailed information on the quantity and concentration of CO₂ that is in the waste stream and the equipment for capture, storage and transportation. Please include cost of construction, operation and maintenance, cost per pound of CO₂ removed by the technologies evaluated and include the feasibility and cost analysis for storage or transportation for these options. Please discuss in detail any site specific safety or environmental impacts associated with such a removal system.

Response:

ExxonMobil is a leader in the research, development and application of CCS and related technologies, with over 30 years of extensive experience in technology that could be transferable to CCS operations. ExxonMobil recognizes CCS is a promising technology for mitigating GHG emissions, but through our experience we also recognize that significant

challenges must be overcome for wide-spread deployment across various industries. Challenges include high capture cost; first-of-a-kind (FOAK) technology deployments in new industrial sectors with unknown technology and process safety risks; and insufficient regulatory frameworks, including management of long-term responsibility, lack of transport infrastructure networks, long-term storage integrity confidence, and uncertain public acceptance of CCS projects. A number of large scale integrated projects have been cancelled over the past several years, both in the US and other parts of the world, generally citing all or a combination of the aforementioned challenges as barriers to the CCS project.

CCS has been evaluated for the proposed project based on technological, environmental, and economic feasibility. In the guidance documents for GHG permitting, USEPA states⁹:

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.

ExxonMobil does not agree with EPA's classification of CCS as "available" for any application other than processing produced natural gas. There are no global examples where capture of CO₂ from a low pressure, low CO₂ concentration flue gas has been demonstrated at a scale and level of reliability necessary for application in a compliance-based scenario. The proposed project, with its numerous emission points and low CO₂ concentration, does not meet the criteria established in the above paragraph, nor does it meet any reasonable definition of BACT because CCS has not been demonstrated as an "available" and "applicable" technology for steam cracking furnaces or an ethylene unit or any similar applications. The proposed project is not analogous to a fossil fuel-fired power plant due to exhaust gas flow rate differences occurring from firing a power plant's turbine compared to firing a steam cracking furnace. A fossil fuel-fired power plant stack volumetric flow rate is an order of magnitude greater than a single steam cracking furnace stack in this permit application.

Nor does the proposed project compare to an industrial facility with high-purity CO₂ streams since the proposed project will construct eight separate sources that will emit very low-purity CO₂ streams. The industrial facilities cited in the above USEPA example are similar to each other in that each has a limited number of stacks and the purity of the CO₂ for most is in the range of 65% (versus ~ 8 % for a steam cracking unit). A steam cracking unit is not a comparable process to hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing by any measure, especially regarding the purity of the CO₂ in the stack, which is less than 8%. USEPA specifically cited CCS technology as "available" for the power

⁹ 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.

plant and high-purity industrial facility streams simply because these are the applications that are either most impactful to reduce total US GHG emissions (in the case of fossil fuel-fired power plants) or may be best suited for CCS technology applications (in the case of hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing) when only CO₂ source gas characteristics are evaluated. CCS is not applicable to steam cracking units because of the low purity CO₂-containing streams emitted from multiple stacks across the facility.

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

Carbon Capture

While several technologies for the post-combustion capture of low-pressure, low-concentration CO₂ may be in development, none have been demonstrated at the scale of the proposed project nor for sources at natural gas fired facilities. Carbon capture for the proposed project would require FOAK technology application that is further complicated by the numerous emission points from the steam cracking furnaces. Any CCS technology will result in additional equipment, operating complexity, and increased energy consumption to operate the add-on equipment. Additional equipment would increase the energy and fuel demand and significantly increase the size of the power generation system, which would lead to more air pollution and wastewater generation at the site.

Further, as stated in the August 2010 Report of the Interagency Task Force on Carbon Capture and Storage¹⁰:

"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 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."

Recovery and purification of CO₂ from the furnace flue gas would require significant additional processing to achieve the necessary CO₂ concentration for effective storage. The furnace exhaust streams are not high-purity streams, as recommended in USEPA's guidance.

¹⁰ 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.

Instead, the furnace exhausts contains less than eight (8) vol% 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 storage.

Once separated, the CO₂ must be compressed, requiring significant additional inputs of energy to accomplish compression of the low pressure CO₂ gas to a supercritical fluid, which is equivalent to a pressure increase of approximately 2,200 psia. This is a complicated process that requires complex equipment with numerous stages of compression integrated with heat removal.

Transport

Once the CO₂ is supercritical, it must be transported to a suitable site for storage or sequestration. Transport via pipeline is the only feasible transportation method for CO₂ recovered from BOP due to the volumes involved. 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 pipeline that would connect the Denbury Green Pipeline to BOP.

It is unknown at this time whether Denbury could or would accept CO₂ from the proposed project, if a pipeline were to be constructed, however, for the purposes of the economic analysis, it has been assumed that a contract would be secured from Denbury Resources and all recovered CO₂ from the proposed project would be accepted into the Green Pipeline.

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. While a case specific evaluation has not been conducted, it is likely suitable storage reservoirs could be found within a reasonable proximity to BOP. There are multiple mature oil and gas fields that could be suitable targets for enhanced oil recovery projects or that could have suitable brine formations either below or above know productions zones that could serve as storage reservoirs. These sites however would require intensive evaluation and would very likely require substantial remedial work to provide the high degree of site and formation integrity necessary for secure storage. One of the biggest challenges that can be expected is the necessity of identifying old wells and ensuring they are securely plugged. Since a specific site has not been identified, estimating the technical feasibility and costs of this option is difficult and highly uncertain since a well that meets Class VI requirements under the UIC regulations would have to be identified and secured for the proposed project. Other potential storage sites that may be available are located in the Permian Basin, but are more than 460 miles from the proposed project site and there are no existing connecting CO₂ pipelines to this location from BOP.

Economic Analysis

Although CCS is not technically or environmentally feasible for the proposed project, a site-specific CCS economic analysis was completed at the request of USEPA. A carbon capture and compression plant was specified with cost estimates by an ExxonMobil Research and Engineering Team specializing in CCS technologies. The Team determined that an amine absorber system would need to be located in close proximity to the eight sources to minimize the extensive duct work required to route each of the eight exhaust stacks together, minimize size of the required air blower, maximize on-stream operation, and achieve ~90% recovery of CO₂ from the exhaust gas. The Furnace Section CO₂ Capture Plant was specified to accept 1,350 tons of total furnace exhaust gas per hour to remove 92 tons of CO₂ per hour. Note that this design is sized for the current proposed project, which will not recover the hydrogen contained in the Tail Gas and will instead blend it with natural gas in fuel gas system. If ExxonMobil were to pursue the option to recover this hydrogen, the carbon capture system would be insufficiently sized to process the flue gas flow rate of eight combined furnaces firing natural gas blended with a recovered hydrogen stream, however, to provide a detailed response to USEPA, a carbon capture system designed for the proposed project has been provided.

A dedicated utility plant would be required to meet the steam and power requirements for the Furnace Section CO₂ Capture Plant; however, this utility plant would generate its own GHG emissions. The CCS design therefore includes capture of CO₂ from the furnace exhaust stacks as well as the additional CO₂ emissions generated by the utility plant. The additional power generated by this utility plant is exported as a credit to the operating cost of the utility plant. The Utility Plant CO₂ Capture Plant was designed to accept 380 tons of utility plant exhaust gas flow per hour to remove approximately 26 tons of CO₂ per hour in an additional amine absorber located near the utility plant emission sources.

Amine regeneration and CO₂ compression would be centrally located to receive the concentrated rich amine streams from the Furnace Section and Utility Plant CO₂ Capture Plants. This design imposes movement of rich and lean amine streams between the two capture plants, as well as cooling water supply and return streams.

The carbon capture and compression cost estimate represents the capital and operating expenses associated with the site-specific carbon capture plant. For purposes of the economic analysis below, it is assumed that a contract would be secured from Denbury Resources to accept CO₂ from BOP, therefore, the transport costs are based on construction and operation and maintenance of a 30-mile pipeline that is eight inches in diameter. This represents an oversimplification of the complexities of the process that would be necessary to secure a long-term disposition for the captured CO₂. The cost estimates for transport and the liability estimate associated with storage were based on the Department of Energy's National Energy Technology Laboratory study "Estimating Carbon Dioxide Transport and Storage Costs", which was recently completed in 2010.

Note that the basis for the cost estimate for storage reflects an oversimplification of since it is a simple transfer of the recovered CO₂ to Denbury and does not estimate costs for items such as site screening and evaluation, injection well construction and equipment, pore space

acquisition, and operating and maintenance costs, therefore this cost estimate is at the lowest possible level and may in fact be significantly underestimating the actual cost for storage if this technology were to be pursued. The cost represented for storage relates to liability, which was estimated at \$5,000,000 per the DOE/NETL 2010 report.

As shown in Table 4-1, carbon capture for the proposed project is estimated to cost \$245.70 per ton of CO₂ avoided or \$198,400,000 annually to avoid ~90% of the CO₂ emissions from the furnaces and required utility plant. This cost includes operating and capital costs. The total cost for carbon capture is \$735,400,000. This is an extraordinarily high cost and would render the proposed project economically unviable if selected.

Table 4-1 Economic Analysis for Carbon Capture and Compression

<i>Cost Type</i>	<i>Units¹¹</i>	<i>Cost (millions \$)</i>
<i>Carbon Capture Plants - Capital and Operating Expense Estimation</i>		
<i>CO₂ Compressor and Intercoolers</i>	<i>\$ (millions)</i>	<i>90.6</i>
<i>Amine Absorber Systems</i>	<i>\$ (millions)</i>	<i>200.0</i>
<i>CO₂ Regeneration/Purification System</i>	<i>\$ (millions)</i>	<i>127.1</i>
<i>Blower, Piping, and Ducting</i>	<i>\$ (millions)</i>	<i>63.8</i>
<i>Utility Plant - Capital and Operating Expense Estimation</i>		
<i>New Utility Plant – Boiler, Boiler Feed Water Treatment and Blower</i>	<i>\$ (millions)</i>	<i>76.2</i>
<i>Cooling Tower, Utilities Header and Piping</i>	<i>\$ (millions)</i>	<i>177.6</i>
<i>Fuel, Utilities, Amine</i>	<i>\$ (millions) / yr</i>	<i>58.6</i>
<i>Total Expense Estimation</i>		
<i>Operating Expense</i>	<i>\$ / Ton CO₂ Avoided</i>	<i>72.6</i>
<i>Capital Expense</i>	<i>\$ / Ton CO₂ Avoided</i>	<i>173.1</i>
<i>Total</i>	<i>\$ / Ton CO₂ Avoided</i>	<i>245.7</i>

¹¹ All monetary estimations have been calculated in 2016 dollars.

Table 4-2 Economic Analysis for CO₂ Transport¹²

Cost Type	Units	Cost Equation	Cost (millions)
Pipeline Materials	\$ Diameter (inches), Length (miles)	$\$64,632 + \$1.85 \times L \times (330.5 \times D^2 + 686.7 \times D + 26,960)$	3.0
Pipeline Labor	\$ Diameter (inches), Length (miles)	$\$341,627 + \$1.85 \times L \times (343.2 \times D^2 + 2,074 \times D + 170,013)$	11.9
Pipeline Miscellaneous	\$ Diameter (inches), Length (miles)	$\$150,166 + \$1.58 \times L \times (8,417 \times D + 7,234)$	3.7
Pipeline Right of Way	\$ Diameter (inches), Length (miles)	$\$48,037 + \$1.20 \times L \times (577 \times D + 29,788)$	1.3
Pipeline Control System	\$		0.110
CO ₂ Surge Tank	\$		1.15
Total Materials and Labor Estimation	\$		21.2
Operating and Maintenance Expense Estimation	\$ / mile / year	\$8,632	5.2
Total Expense Estimation	\$		26.4
Amortized Cost ¹³	\$/yr		5.2
Total Cost per Ton of CO₂ Avoided			
Total Cost	\$ / Ton CO ₂ Avoided		6.4

The total estimated cost for CO₂ transport is \$5,200,000 per year or \$6.4 per ton of CO₂ avoided. This cost is for an eight-inch diameter pipeline 30 miles in length to transport supercritical CO₂ from BOP to the Denbury Green Pipeline. The cost includes required materials and labor, equipment such as a surge tank and control system, right of way, construction, and operating and maintenance costs.

¹² National Energy Technology Laboratory, Estimating Carbon Dioxide Transport and Storage Costs, United States Department of Energy, Page 5, DOE/NETL-2010/1447.

¹³ A capital charge rate of 19% was assumed with an expected equipment life of 20 years.

Table 4-3 Economic Analysis for CCS

CCS Technology for CO₂ Emissions	Cost (\$ per ton of CO₂ Avoided)	Tons of CO₂ Avoided per Year¹⁴	Total Annualized Cost¹⁵ (Million \$ per year)
Capture and Compression	\$245.7	807,374	\$198.4
Transport	\$6.4	807,374	\$5.2
Storage	\$1.2 ¹⁶	807,374	\$1.0
Total CCS Cost	\$253.3	807,374	\$204.6

The total cost for capturing and compressing CO₂ generated by the proposed project, capturing and compressing CO₂ generated by the CO₂ capture equipment, transporting supercritical CO₂ 30 miles, and providing liability coverage for storage of the project's CO₂ is estimated at \$253.3 per ton of CO₂ avoided which equates to an annualized cost of \$204,600,000 per year. An annualized CCS cost of \$204.6 million dollars would render the proposed project unviable, even for this multi-billion dollar investment proposed by ExxonMobil.

While CCS is a viable technology to mitigate CO₂ emissions in some limited specific industries, it is not an available or applicable technology for steam cracking furnaces due to the low pressure, low CO₂ concentration streams that are distributed across multiple sources and the relatively small scale in comparison to a power plant. Based on the aforementioned technological and environmental challenges and the extraordinarily high annualized cost for capture, transport, and storage of CO₂, CCS as a combined technology is not considered technically, environmentally, or economically feasible for reducing GHG emissions from the proposed project. CCS is eliminated as a potential control option in the BACT analysis for CO₂ emissions from the proposed project.

- On page 4-10 of the permit application in the entitled, Decoking Activities, the application identified two potential practices that are technically feasible for CO₂ control for decoking operations which are limiting air/steam during the decoking process and minimizing the amount of coke formed in the furnace through proper design and operation.

¹⁴ This represents ~90% of the total CO₂ emissions from the eight furnaces and utility plant.

¹⁵ Total Annual Cost represents an amortized cost for the capital expenditure and operating and maintenance costs. A capital charge rate of 19% was assumed with an expected equipment life of 20 years.

¹⁶ It is assumed that Denbury Resources will receive CO₂ from the proposed project and will incorporate the entire flow into its operations. Storage costs are therefore estimated to consist of liability, which is \$5,000,000 per the DOE/NETL 2010 report. This is an oversimplification of the storage costs that would be associated with CCS for the proposed project.

- A. Please provide supplemental data that will discuss the design of the proposed furnaces and how it will translate to decreasing coking potential as is asserted in the application?

Response:

Coking is inherent to the steam cracking process. Coke is a by-product of the cracking reaction and must be periodically removed from the radiant tubes before reaching a process or mechanical constraint. The process to remove the coke requires the furnace to be taken offline and cleaned through a steam-air decoking process. The proposed furnaces are designed to minimize the coking rates since the periodic decoking operation reduces the overall plant efficiency and results in an economic penalty to the production process. ExxonMobil's extensive experience, both designing and operating furnaces, results in the unique position to incorporate the operational learnings of the coking process into the proprietary furnace designs.

The proposed furnace design optimizes the complex interactions of the radiant tube mechanical design, the process flow conditions, and the heat distribution to the process fluid with the aim of minimizing coking rates. Uniform heat distribution across the furnace results in the optimal cracking process and lower coking rates. The furnace control system, along with sonic flow venturies, facilitates uniform process flow distribution to each radiant tube. In addition, the most recent tools and modeling techniques assist the design effort to optimize heat distribution in the furnace. Computation Fluid Dynamics (CFD) will be used to validate the radiant box burner arrangement and heat distribution to the radiant tubes.

The project will also minimize the impact of other known coking accelerators, such as contaminants in the feed and steam streams. The project will include facilities, as required, to deliver contaminant-free feed and steam to the furnaces.

- B. What percentage of coke reduction in the tubes will occur in lbs coke/lbs of product processed? Please include technical data that supports your conclusions, as well as the associated decrease in GHG per pound of product.

Response:

Minimizing furnace coking rates is achieved through furnace design, operation, and maintenance practices. The furnace design considers the complex interactions between radiant tube design, process flow conditions, and heat distribution (as discussed in the response to Item 8A).

It is not possible to quantify the percent coke reduction against a nominal standard since all pyrolysis furnaces operate with different feeds and operating conditions. The estimation of coke volume in the radiant tubes is challenging as the direct measurement of coke thickness in a radiant tube is not possible. The coke volume was estimated based on operational experience and data collected after furnace shutdowns.

- C. What design or process operation modifications will ensure the uniform distribution of the feed and heating in the tubes?

Response:

Uniform feed distribution in the furnace tubes is achieved using the design process control system combined with sonic flow venturies at the entrance to each radiant coil. In addition, the CFD model (refer to Response 8A) is a tool employed to ensure the design of the furnace will deliver uniform heat distribution to the tubes in the firebox. These tools are key components to ensuring the design delivers the staged economic performance of the furnace.

Finally, the project will install knock-out facilities in the fuel gas system to mitigate the risk of burner fouling due to liquid carry over that would impact the heat distribution and therefore the furnace run-lengths.

9. Being mindful of EPA's PSD and Title V Permitting Guidance for GHG dated March, 2011 on page 17, which states the following:

"The CAA and corresponding implementing regulations require that a permitting authority conduct a BACT analysis on a case-by-case basis, and the permitting authority must evaluate the amount of emissions reductions that each available emissions-reducing technology or technique would achieve, as well as the energy, environmental, economic and other costs associated with each technology or technique. Based on this assessment, the permitting authority must establish a numeric emissions limitation that reflects the maximum degree of reduction achievable for each pollutant subject to BACT through the application of the selected technology or technique. However, if the permitting authority determines that technical or economic limitations on the application of a measurement methodology would make a numerical emissions standard infeasible for one or more pollutants, it may establish design, equipment, work practices or operational standards to satisfy the BACT requirement."

Please propose short-term emission limitations or efficiency based limits for all PSD emissions sources. Please provide an analysis that substantiates any reasons for infeasibility of a numerical emission limitation. For the emissions sources where numerical emission limitations are infeasible, please propose an operating work practice standard that can be practically enforceable.

Response:

ExxonMobil has proposed annual numerical emission limits for each source in Table 3-1 Emission Point Summary contained in Attachment 1 to this letter. Table 3-2 located in Attachment 4 has been developed to summarize the proposed work practice standards and operating limits for the proposed project, which reflect appropriate short-term enforceable limits where feasible. Note that it is not feasible to adhere to a short-term numerical emission limits for intermittent emission sources, such as the Decoke Drum, Acetylene

Converter Regeneration Vent, and engines. Refer to Attachment 4 to this letter to view Table 3-2 Work Practice Standards and Operating Limits.

10. On page 4-16 of the permit application, it states, "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." Please specify level of LDAR to be used and the basis of elimination for the other LDAR programs.

Response:

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

An as-observed AVO program achieves a control efficiency equivalent to 28LAER; therefore, employing this program for components in non-VOC, natural gas service will meet or exceed BACT. Refer to Attachment 4 to this letter for a summary of the proposed work practice standards and operating limits for fugitive equipment components.

Additionally, the fugitive emission limits were removed from Table 3-1 Emission Point Summary since fugitive emissions are estimates only, are based on factors derived for a statistical sample, and are not specific to any single piping component or specifically for natural gas service; however, the TCEQ's 28VHP with CNQT and AVO LDAR programs are practically enforceable and are appropriate BACT requirements. Refer to Attachment 1 to this letter for the revised Table 3-1 Emission Point Summary and to Attachment 4 to this letter for a summary of the proposed work practice standards and operating limits for fugitive equipment components.

Calculations

11. Please provide the percent efficiency used to calculate the annual average heat input capacity of natural gas combustion for the cracking furnaces. Please provide benchmarking data how this heat input capacity was obtained and how it compares to other recently permitted units nationally?

Response:

Furnace efficiency is calculated based on the furnace stack temperature, fuel gas composition, excess oxygen, and estimated casing heat loss. Furnace exhaust stack temperature is an appropriate surrogate for thermal efficiency and can be easily monitored. The minimum estimated furnace efficiency during on-line operation is 92% based on 2% casing heat loss and 325°F maximum stack temperature. ExxonMobil proposes using a

continuously monitored furnace stack temperature as a metric for energy efficiency. The proposed limit is 325°F during on-line operation (furnace producing ethylene) on a 365-day rolling average basis. This definition excludes decoking operations, maintenance, start-ups and shutdowns. This value falls within the range of two recent GHG final permits (309-340°F) for pyrolysis furnaces.

As described in the response to Item 5, complete combustion can commercially be achieved at low excess oxygen as measured by online analyzers, during normal operation, which results in high furnace efficiency and low GHG emissions.

12. Please provide supporting technical data that was used to calculate the CO₂e emission calculations for in the decoking emissions calculations. How was the mole ratio of CO₂/CO derived or obtained? Please provide a technical discussion how the estimation of one decoke per month per furnace was obtained? Please indicate if benchmark data was used in this estimation?

Response:

The estimation of the coke volume in the radiant tubes is challenging as direct measurement of the coke thickness in a radiant tube is not possible. The coke volume was estimated based on operational experience and data collected after furnace shutdowns.

The decoking process is a combination of coke spalling and burning. The quantity of coke burned is a function of the air-to-steam ratio, temperature, and effluent velocity, which vary during the decoking process. The emission calculations are based on an estimate of 50% combusted coke, consistent with observations. Some CO is emitted with CO₂ during the decoke process. A molar ratio of 75/25 was initially assumed for CO₂/CO, however, for purposes of this GHG permit application, a conservative assumption of full conversion of the burned coke to CO₂ has been assumed and is represented in the updated emission calculations and revised Table 3-1 Emission Point Summary in Attachment 1 to this letter.

The furnace predicted run length was estimated based on ExxonMobil proprietary coking models. These models are semi-empirical and have been calibrated with plant data over decades of experience. The actual run length will vary based on the furnace operation and radiant coil age. There are many different factors that may drive a furnace to decoke. In most cases, the furnace will reach operational or mechanical constraints. However, there are other reasons to decoke a furnace including running at reduced rates as a result of a downstream constraint, a pending unit shutdown, operational upset, etc.

The predicted run length of 30 days is not intended to imply an operating constraint. ExxonMobil does not propose to limit decoking operations since decoking is a key practice to safe and efficient operation of the plant. As discussed in the response to Item 8A, a low coking rate will be achieved through a good furnace design and operational control. To demonstrate this, the furnaces will adhere to CO concentrations below 50 ppm corrected for 3% oxygen on a 12-month rolling average basis.

13. Aforementioned on page 2-1 of the permit application, it is indicated that “the furnaces will fire imported natural gas or a blended fuel gas that consists of imported natural gas and tail gas.” Please provide the blended fuel gas analysis results to determine the fuel’s carbon content factor used in equation C-5 from 40 CFR 98, Subpart C to calculate GHG emissions rates. What will be ExxonMobil’s preferred method of monitoring and recordkeeping for the determination of fuel quality, i.e., continuous gas chromatograph, fuel meters, etc.

Response:

Refer to Attachment 1 to this letter for the blended fuel gas analysis results. ExxonMobil proposes to comply with 40 CFR 98 Subpart C requirements by installing an online analyzer to determine fuel quality. Refer to Attachment 4 to this letter for a summary of the proposed work practice standards and operating limits for the furnace section.

ATTACHMENT 1

- **Updated Table 3-1 Emission Point Summary**
- **Revised Fuel Compositions**
- **Revised Emissions Calculations for Furnaces and Decoking Drum**
- **Revised Emissions Calculations for Staged Flare System**
- **Emission Calculations for Fugitives**
- **Emission Calculations for New Duct Burners**
- **Emission Calculations for Engines**
- **Emission Calculations for Acetylene Converter Regeneration Vent**
- **Emission Calculations for Sources with No Requested GHG Increase**

**Table 3-1
Emission Point Summary**

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

Air Contaminant Data					
Emission Point			Component or Air Contaminant Name	GHG Emission Rate (ton/yr)	CO ₂ e Emission Rate (ton/yr) ^A
EPN	FIN	Name			
XXAF01-ST	XXAF01	XXA Furnace Combustion Vent	CO ₂	122,750	122,750
			N ₂ O	2	620
			CH ₄	6	126
XXBF01-ST	XXBF01	XXB Furnace Combustion Vent	CO ₂	122,750	122,750
			N ₂ O	2	620
			CH ₄	6	126
XXCF01-ST	XXCF01	XXC Furnace Combustion Vent	CO ₂	122,750	122,750
			N ₂ O	2	620
			CH ₄	6	126
XXDF01-ST	XXDF01	XXD Furnace Combustion Vent	CO ₂	122,750	122,750
			N ₂ O	2	620
			CH ₄	6	126
XXEF01-ST	XXEF01	XXE Furnace Combustion Vent	CO ₂	122,750	122,750
			N ₂ O	2	620
			CH ₄	6	126
XXFF01-ST	XXFF01	XXF Furnace Combustion Vent	CO ₂	122,750	122,750
			N ₂ O	2	620
			CH ₄	6	126
XXGF01-ST	XXGF01	XXG Furnace Combustion Vent	CO ₂	122,750	122,750
			N ₂ O	2	620
			CH ₄	6	126
XXHF01-ST	XXHF01	XXH Furnace Combustion Vent	CO ₂	122,750	122,750
			N ₂ O	2	620
			CH ₄	6	126
XXAB-DEC	XXABDEC	XXA/B Furnace Decoke Vent	CO ₂	199	199
			N ₂ O	1	310
			CH ₄	1	21

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

^B Use of LDAR program as practically enforceable limit.

EPN = Emission Point Number
FIN = Facility Identification Number

**Table 3-1
Emission Point Summary**

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

Air Contaminant Data					
Emission Point			Component or Air Contaminant Name	GHG Emission Rate (ton/yr)	CO ₂ e Emission Rate (ton/yr) ^A
EPN	FIN	Name			
XXCD-DEC	XXCDDEC	XXC/D Furnace Decoke Vent	CO ₂	199	199
			N ₂ O	1	310
			CH ₄	1	21
XXEF-DEC	XXEFDEC	XXE/F Furnace Decoke Vent	CO ₂	199	199
			N ₂ O	1	310
			CH ₄	1	21
XXGH-DEC	XXGHDEC	XXG/H Furnace Decoke Vent	CO ₂	199	199
			N ₂ O	1	310
			CH ₄	1	21
FLAREXX1 and FLAREXX2	FLAREXX1 and FLAREXX2	Staged Flare System	CO ₂	86,574	86,574
			N ₂ O	5	1,550
			CH ₄	115	2,415
BOPXXFUG	BOPXXAREA	Fugitives	CO ₂	NA ^B	NA ^B
			N ₂ O	NA ^B	NA ^B
			CH ₄	NA ^B	NA ^B
HRSG05	HRSG05	Duct Burners	CO ₂	397,231	397,231
			N ₂ O	1	310
			CH ₄	8	168
DIESELXX01 DIESELXX02 DIESELXX03	DIESELXX01 DIESELXX02 DIESELXX03	Backup Generator Engines	CO ₂	223	223
			N ₂ O	1	310
			CH ₄	1	21
DIESELXXFW1 DIESELXXFW2	DIESELXXFW1 DIESELXXFW2	Firewater Booster Pump Engines	CO ₂	67	67
			N ₂ O	1	310
			CH ₄	1	21
ACETCONVXX	ACETCONVXX	Acetylene Converter Regeneration Vent	CO ₂	25	25
			N ₂ O	1	310
			CH ₄	1	21
Proposed Project Compliance Totals			CO ₂	1,466,916	1,466,916
			N ₂ O	29	8,990
			CH ₄	178	3,738
			Total GHG	1,467,123	1,479,644

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

^B Use of LDAR program as practically enforceable limit.

ExxonMobil Chemical Company
 Baytown Chemical Plant
 Greenhouse Gas Fuel Gas and Flare Gas Representations

PIPELINE QUALITY NATURAL GAS						
Constituent	Composition (mol%)	MW (lb/lbmol)	Composition (wt%)	HHV (Btu/lbmol)	HHV (Btu/scf)	Carbon Content (lb C / lb Constituent)
Methane	96%	16.04	89.95%	384,517	953.75	0.75
Ethane	1.81%	30.07	3.19%	680,211	31.94	0.80
Ethylene	0.00%	28.05	0.00%	612,645	0.00	0.86
Propane	0.33%	44.10	0.85%	983,117	8.42	0.82
n-Butane	0.18%	58.12	0.61%	1,279,191	5.97	0.83
C5+ (as Hexane)	0.13%	86.18	0.66%	1,680,855	5.67	0.84
N2	0.32%	28.00	0.53%	0	0.00	0.00
CO	0.00%	28.01	0.00%	122,225	0.00	0.43
CO2	1.63%	44.01	4.21%	0	0.00	0.27
Total	100.00%	17.05	100.00%	387,642	1005.75	0.73

FURNACE BLENDED FUEL GAS COMPOSITION						
Constituent	(mol%)	(lb/lbmol)	(wt%)	(Btu/lbmol)	(Btu/scf)	(lb C / lb Constituent)
Hydrogen	74%	2.02	25.36%	123,364	235.70	0.000
Methane	25%	16.04	69.42%	384,517	253.30	0.748
Ethane	0.21%	30.069	1.08%	680,211	3.71	0.798
Ethylene	0.27%	28.054	1.29%	612,645	4.29	0.855
Propane	0.04%	44.096	0.30%	983,117	1.02	0.816
n-Butane	0.02%	58.123	0.20%	1,279,191	0.66	0.826
CO	0.21%	28.010	1.00%	122,225	0.67	0.428
CO2	0.18%	44.010	1.35%	0	0.00	0.273
Total	100%	5.87	100%	192,462	499.35	0.551

ETHANE TO MULTI-POINT FLARE PILOTS						
Constituent	(mol%)	(lb/lbmol)	(wt%)	(Btu/lbmol)	(Btu/scf)	(lb C / lb Constituent)
Methane	1.00%	16.04	0.53%	384,517	9.98	0.748
Ethane	95.50%	30.069	94.40%	680,211	1685.41	0.798
Propane	3.50%	44.096	5.07%	983,117	89.28	0.816
Total	100%	30.42	100%	880,241	1784.67	0.799

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

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ExxonMobil Chemical Company
 Baytown Chemical Plant
 Greenhouse Gas Fuel Gas and Flare Gas Representations

REPRESENTATIVE OFF GAS TO FLAREXX						
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
 Total Furnace
 Greenhouse Gas Emissions Calculations

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
1. CO₂ Annual Emission Rate Calculations		
CO ₂ Furnace Firing NG Emission Rate =	4,602 TPY	
CO ₂ Furnace Firing Blended FG Emission Rate =	118,148 TPY	
CO ₂ Annual Emission Rate =	122,750 TPY	Sum of annual CO ₂ emissions from all streams
2. N₂O Annual Emission Rate Calculations		
N ₂ O Furnace Firing NG Emission Rate =	1 TPY	
N ₂ O Furnace Firing Blended FG Emission Rate =	1 TPY	
N ₂ O Annual Emission Rate =	2 TPY	Sum of annual N ₂ O emissions from all streams
3. CH₄ Annual Emission Rate Calculations		
CH ₄ Furnace Firing NG Emission Rate =	1 TPY	
CH ₄ Furnace Firing Blended FG Emission Rate =	5 TPY	
CH ₄ Annual Emission Rate =	6 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 =	123,496 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
 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	79,609 MMBtu/yr	$= Q_V * HV_{AVG}$
Total Furnace Natural Gas Volume Flow Q_V	79 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
2. CO₂ Emission Rate Calculations		
CO ₂ Annual Emission Rate =	4,602 TPY	$= MW_{CO_2} / MW_{Carbon} * Q_V * F_{CC} * M_V / V_{MS} / 2000$ 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
N ₂ O Annual Emission Rate =	1 TPY	$= H * F_{N_2O} / 4536$ kg/lb / 2000 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
CH ₄ Annual Emission Rate =	1 TPY	$= H * F_{CH_4} / 4536$ kg/lb / 2000 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
CO ₂ e Annual Emission Rate =	4,933 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
 Furnace Firing Blended Fuel 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 Blended Fuel Gas HV_{AVG}	501 Btu/scf	Calculated from representative stream speciation
Blended Fuel Gas Heat Input to Furnace H	3,809,831 MMBtu/yr	$= Q_V * HV_{AVG}$
Total Furnace Blended Fuel Gas Volume Flow Q_V	7,601 MMscf/yr	Based on expected firing rate
Avg. Molecular Weight of Blended Fuel Gas M_V	6.0 lb/lb-mol	Calculated from representative stream speciation
Carbon Content of Blended Fuel Gas F_{CC}	0.55 lb_C/lb_Gas	Calculated from representative stream speciation
2. CO₂ Emission Rate Calculations		
CO₂ Annual Emission Rate =	118,148 TPY	$= MW_{CO_2}/MW_{Carbon} * Q_V * F_{CC} * M_V / V_{MS} / 2000$ 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	$= H * F_{N_2O} / 4536$ kg/lb / 2000 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 =	5 TPY	$= H * F_{CH_4} / 4536$ kg/lb / 2000 lb/ton Equation C-8
5. CO₂e Emission Rate Calculations		
CO ₂ CO ₂ e Factor F_{eCO_2}	1 ton _{CO_2} /ton _{CO_2e}	40 CFR 98, Table A-1
N ₂ O CO ₂ e Factor F_{eN_2O}	310 ton _{N_2O} /ton _{CO_2e}	40 CFR 98, Table A-1
CH ₄ CO ₂ e Factor F_{eCH_4}	21 ton _{CH_4} /ton _{CO_2e}	40 CFR 98, Table A-1
CO₂e Annual Emission Rate =	118,563 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.

ExxonMobilChemical Company
 Baytown Olefins Plant
 Decoking Drum
 Greenhouse Gas Emissions Calculations

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
1. General Values and Calculations		
Total Coke Produced Annually C_A	108,184 lb/yr	Based on process knowledge
Percent Coke Oxidized C_{OX}	50%	Based on process knowledge
Percent Coke Spalled	50%	Based on process knowledge
Total Coke Oxidized Annually $C_{OX,A}$	54 TPY	$= C_A * C_{OX} * 2,000 \text{ lb/yr}$
2. CO₂ Emission Rate Calculations		
CO ₂ Emission Factor F_{CO_2}	102.41 kg/MMBtu	40 CFR 98, Table C-1
Carbon Content of Coke CC_{Coke}	1 lb carbon / lb coke	Conservative estimate
CO ₂ Annual Emission Rate =	199 TPY	$= C_{OX,A} * CC_{Coke} * MW_{CO_2} / MW_{Carbon}$ Equation Y-11
2. N₂O Emission Rate Calculations		
N ₂ O Emission Factor F_{N_2O}	6.E-04 kg/MMBtu	40 CFR 98, Table C-2
N ₂ O Annual Emission Rate =	1 TPY	$= CO_2 \text{ tpy} * F_{N_2O} / F_{CO_2}$ Equation Y-8
2. CH₄ Emission Rate Calculations		
CH ₄ Emission Factor F_{CH_4}	3.E-03 kg/MMBtu	40 CFR 98, Table C-2
CH ₄ Annual Emission Rate =	1 TPY	$= CO_2 \text{ tpy} * F_{CH_4} / F_{CO_2}$ Equation Y-9
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
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 =	530 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.

ExxonMobi 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 =	48,497 TPY	
CO ₂ Pilot Gas Annual Emission Rate =	1,958 TPY	
CO ₂ Annual Emission Rate =	86,574 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 =	3 TPY	
N ₂ O Annual Emission Rate =	5 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 =	4 TPY	
CH ₄ Pilot Gas Annual Emission Rate =	10 TPY	
CH ₄ Annual Emission Rate =	115 TPY	Sum of annual CH ₄ emissions from all streams
4. 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 =	90,539 TPY	= Σ (TPY * F _{e_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
 FLAREXX1 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 flaring 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
Assumed Flare Efficiency E_F	98%	40 CFR 98 Subpart Y
Flare Efficiency Correction Factor C_F	0.02	$= (1 - E_F) / E_F$
2. CO₂ Emission Rate Calculations		
CO₂ Annual Emission Rate =	36,119 TPY	$= E_F * MW_{CO2} / MW_C * Q_V * 10^6 * M_V / V_{MS} * CC_{gas} / 2000 \text{ lb/ton}$ 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}	0.37	Calculated from representative stream speciation
CH₄ Annual Emission Rate =	101 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 =	38,560 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
 FLAREXX2 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 intermittent flaring 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_{CO_2}	60 kg/MMBtu	40 CFR 98 Subpart Y
Assumed Flare Efficiency E_F	99.8%	Assumed flare combustion efficiency
Flare Efficiency Correction Factor C_F	0.002	$= (1 - E_F) / E_F$
2. CO₂ Emission Rate Calculations		
CO ₂ Annual Emission Rate =	48,497 TPY	$= E_F * MW_{CO_2} / MW_C * Q_V * M_V / V_{MS} * CC_{gas} / 2000 \text{ lb/ton}$ Equation Y-1a
3. N₂O Emission Rate Calculations		
N ₂ O Emission Factor F_{N_2O}	6.0E-04 kg/MMBtu	40 CFR 98 Subpart Y
N ₂ O Annual Emission Rate =	1 TPY	$= CO_2 \text{ TPY} * F_{N_2O} / F_{CO_2}$ 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}	0.04	Calculated from representative stream speciation
CH ₄ Annual Emission Rate =	4 TPY	$= (CO_2 \text{ TPY} * F_{CH_4} / F_{CO_2}) + (CO_2 \text{ TPY} * C_F * MW_{CH_4} / MW_{CO_2} * f_{CH_4})$ Equation Y-4
5. CO₂e Emission Rate Calculations		
CO ₂ CO ₂ e Factor 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 =	48,891 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
 Pilot Gas to FLAREXX1
 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	Design rate
Avg. Molecular Weight of Natural Gas M_V	17.0 lb/lb-mol	Calculated from stream speciation
Avg. Carbon Content of Natural Gas CC_{gas}	0.73 lb _C /lb _{gas}	Calculated from 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
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 =	152 TPY	= $0.98 * MW_{CO2} / MW_C * Q_V * t * M_V / V_{MS} * CC_{gas} / 2000$ lb/ton Equation Y-1a
3. N₂O Emission Rate Calculations		
N ₂ O Emission Factor F_{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}	0.95	Calculated from representative stream speciation
CH ₄ Annual Emission Rate =	2 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 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 =	504 TPY	= Σ (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
 Pilot Gas (Ethane) to FLAREXX2
 Greenhouse Gas Emissions

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 Ethane Volume Flow Q_V	900 scf/hr	Design rate
Avg. Molecular Weight of Ethane M_V	30.4 lb/lb-mol	Calculated from representative stream speciation
Avg. Carbon Content of Ethane CC_{gas}	0.80 lb _C /lb _{gas}	Calculated from representative stream speciation
CO ₂ Emission Factor F_{CO2}	62.64 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 =	894 TPY	= $0.98 * MW_{CO2} / MW_C * Q_V * t * M_V / V_{MS} * CC_{gas} / 2000$ lb/ton Equation Y-1a
3. N₂O Emission Rate Calculations		
N ₂ O Emission Factor F_{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
Vt. fraction of carbon in fuel gas from CH ₄ f_{CH4}	0.01	Calculated from representative stream speciation
CH ₄ Annual Emission Rate =	1 TPY	= $(CO_2$ TPY * $F_{CH4} / F_{CO2}) + (CO_2$ TPY * $C_F * MW_{CH4} / MW_{CO2} * f_{CH4})$ Equation Y-4
5. 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 =	1,225 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
 Pilot Gas (Natural Gas) to FLAREXX2
 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	1,800 scf/hr	Design rate
Avg. Molecular Weight of Natural Gas M_V	17.0 lb/lb-mol	Calculated from stream speciation
Avg. Carbon Content of Natural Gas CC_{gas}	0.73 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 =	912 TPY	$= 0.98 * MW_{CO_2} / MW_C * Q_V * t * M_V / V_{MS} * CC_{gas} / 2000 \text{ lb/ton}$ 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	$= CO_2 \text{ TPY} * F_{N_2O} / F_{CO_2}$ 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 =	7 TPY	$= (CO_2 \text{ TPY} * F_{CH_4} / F_{CO_2}) + (CO_2 \text{ TPY} * C_F * MW_{CH_4} / MW_{CO_2} * f_{CH_4})$ Equation Y-4
5. CO₂e Emission Rate Calculations		
CO ₂ CO ₂ e Factor F_{e,CO_2}	1 ton _{CO₂} /ton _{CO₂e}	40 CFR 98, Table A-1
N ₂ O CO ₂ e Factor F_{e,N_2O}	310 ton _{N₂O} /ton _{CO₂e}	40 CFR 98, Table A-1
CH ₄ CO ₂ e Factor F_{e,CH_4}	21 ton _{CH₄} /ton _{CO₂e}	40 CFR 98, Table A-1
CO ₂ e Annual Emission Rate =	1,369 TPY	$= \sum (TPY * F_{e,i})$

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
 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
 Duct Burner
 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}	1,006 Btu/scf	Calculated from representative stream speciation
Natural Gas Heat input to Duct Burner H	6,771,480 MMBtu/yr	$= Q_V * HV_{AVG}$
Total Natural Gas Volume Flow Q_V	6,733 MMscf/yr	Based on expected firing rate
Avg. Molecular Weight of Natural Gas M_V	17.0 lb/lb-mol	Calculated from representative stream speciation
Carbon Content of Natural Gas F_{CC}	0.73 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 =	397,231 TPY	$= MW_{CO_2} / MW_{Carbon} * Q_V * 10^6 * F_{CC} * M_V / V_{MS} / 2000 \text{ lb/ton}$ 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	$= H * F_{N_2O} / 0.4536 \text{ kg/lb} / 2000 \text{ lb/ton}$ 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 =	8 TPY	$= H * F_{CH_4} / 0.4536 \text{ kg/lb} / 2000 \text{ lb/ton}$ 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 =	397,709 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
 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
Total Generator Capacity hp	4,023 hp	= W * 1341.02 hp/MW
Thermal Efficiency of Engine Eff _T	45%	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
Annual Period of Diesel Firing t	120 hr/year	Based on expected operating hours
2. CO₂ Emission Rate Calculations		
CO ₂ Emission Factor F _{CO2}	73.96 kg/MMBtu	40 CFR 98, Table C-1
CO₂ Annual Emission Rate =	223 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
N₂O 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
CH₄ 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
CO₂e Annual Emission Rate =	554 TPY	= Σ (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	1,200 hp	Based on process knowledge per engine
Thermal Efficiency of Engine Eff _T	45%	
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	814 MMBtu/yr	Based on process knowledge per engine
Annual Period of Diesel Firing t	120 hr/year	Based on expected operating hours for testing and maintenance per engine
2. CO₂ Emission Rate Calculations		
CO ₂ Emission Factor F _{CO₂}	73.96 kg/MMBtu	40 CFR 98, Table C-1
CO₂ Annual Emission Rate =	67 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
N₂O 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
CH₄ 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
CO₂e Annual Emission Rate =	398 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.

ExxonMobil Chemical Company
 Baytown Olefins Plant
 Acetylene Converter Regeneration Vent
 Greenhouse Gas Emissions Calculations

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
1. General Values and Calculations		
Total Coke Generated Annually C_A	13,230 lb/yr	Based on process knowledge
Percent Coke Oxidized C_{Ox}	100%	Conservative estimate
Total Coke Oxidized Annually $C_{Ox,A}$	7 TPY	$= C_A * C_{Ox} * 2,000 \text{ lb/yr}$
2. CO₂ Emission Rate Calculations		
CO ₂ Emission Factor F_{CO2}	102.41 kg/MMBtu	40 CFR 98, Table C-1
Carbon Content of Coke CC_{Coke}	1	Conservative value
CO ₂ Annual Emission Rate =	25 TPY	$= C_{Ox,A} * CC_{Coke} * MW_{CO2} / MW_{Carbon}$ Equation Y-11
2. N₂O Emission Rate Calculations		
N ₂ O Emission Factor F_{N2O}	6.E-04 kg/MMBtu	40 CFR 98, Table C-2
N ₂ O Annual Emission Rate =	1 TPY	$= CO_2 \text{ tpy} * F_{N2O} / F_{CO2}$ Equation Y-10
2. CH₄ Emission Rate Calculations		
CH ₄ Emission Factor F_{CH4}	3.E-03 kg/MMBtu	40 CFR 98, Table C-2
CH ₄ Annual Emission Rate =	1 TPY	$= CO_2 \text{ tpy} * F_{CH4} / F_{CO2}$ Equation Y-9
3. 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 =	356 TPY	$= \Sigma (TPY * Fe_x)$

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

ExxonMobil Chemical Company
 Baytown Olefins Plant
 Cooling Tower
 Greenhouse Gas Emissions Calculations

Parameter Name & Variable	Value & Units	Calculation Notes
1. General Values and Calculations		
Density of Water d_{H_2O}	8.34 lb/gal	
Total Throughput Q_V	195,000 gal/min	Based on expected flow rate
Annual Period of Usage t	8,760 hr/yr	Based on expected operating hours
2. CO₂ Emission Rate Calculations		
CO ₂ Concentration $CONC_{CO_2}$	0 ppmw	Calculated based on site-specific speciation
CO ₂ Annual Emission Rate =	0 TPY	$= Q_V * 60 \text{ min/hr} * d_{H_2O} * CONC_{CO_2} / 10^6 * t / 2000 \text{ lb/ton}$
3. N₂O Emission Rate Calculations		
N ₂ O Concentration $CONC_{N_2O}$	0 ppmw	Calculated based on site-specific speciation
N ₂ O Annual Emission Rate =	0 TPY	$= Q_V * 60 \text{ min/hr} * d_{H_2O} * CONC_{N_2O} / 10^6 * t / 2000 \text{ lb/ton}$
3. CH₄ Emission Rate Calculations		
CH ₄ Concentration $CONC_{CH_4}$	0 ppmw	Calculated based on site-specific speciation
CH ₄ Annual Emission Rate =	0 TPY	$= Q_V * 60 \text{ min/hr} * d_{H_2O} * CONC_{CH_4} / 10^6 * t / 2000 \text{ lb/ton}$
4. CO₂e Emission Rate Calculations		
CO ₂ CO ₂ e Factor F_{eCO_2}	1 $\text{ton}_{CO_2} / \text{ton}_{CO_2e}$	40 CFR 98, Table A-1
N ₂ O CO ₂ e Factor F_{eN_2O}	310 $\text{ton}_{N_2O} / \text{ton}_{CO_2e}$	40 CFR 98, Table A-1
CH ₄ CO ₂ e Factor F_{eCH_4}	21 $\text{ton}_{CH_4} / \text{ton}_{CO_2e}$	40 CFR 98, Table A-1
CO ₂ e Annual Emission Rate =	0 TPY	$= \Sigma (\text{TPY} * F_{e_i})$

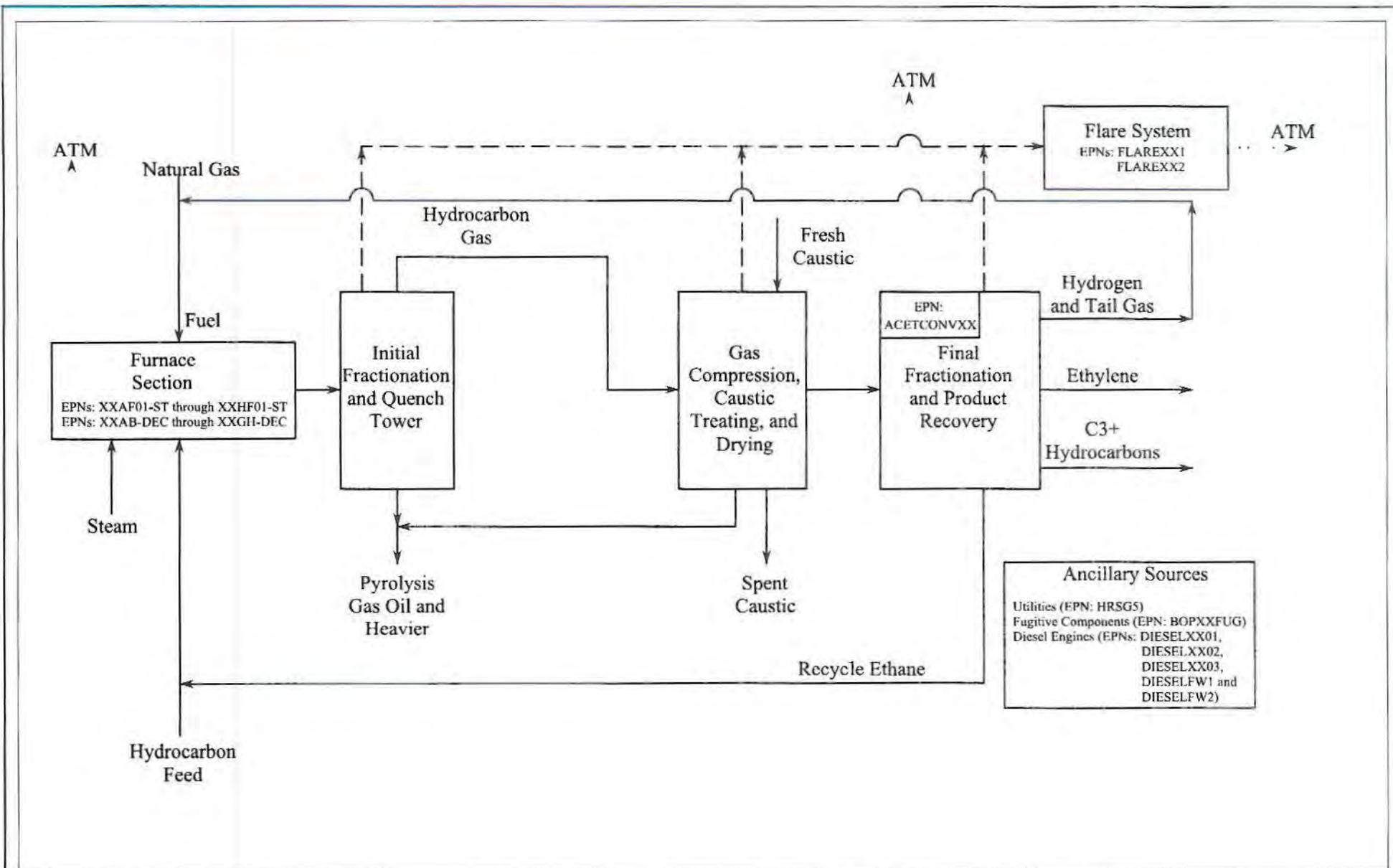
Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.

ExxonMobil Chemical Company
 Baytown Olefins Plant
 Tanks
 Greenhouse Gas Emissions Calculations

Parameter Name & Variable	Value & Units	Calculation Notes
1. General Values and Calculations		
Adjustment Factor S	1.90	Engineering judgement
XXZLTK16 Reference Annual VOC Emission Rate $A_{XXZLTK16}$	0.11 TPY	Estimate based on analysis of existing operations
XXZTK05 Reference Annual VOC Emission Rate $A_{XXZTK05}$	0.19 TPY	Estimate based on analysis of existing operations
Total Reference Annual VOC Emission Rate A_{Em}	0.30 TPY	$= A_{XXZLTK16} + A_{XXZTK05}$
2. CO₂ Emission Rate Calculations		
CO ₂ Concentration $CONC_{CO_2}$	0 wt%	Calculated based on site-specific speciation
CO ₂ Annual Emission Rate =	0 TPY	$= A_{Em} * S * CONC_{CO_2}$
3. N₂O Emission Rate Calculations		
N ₂ O Concentration $CONC_{N_2O}$	0 wt%	Calculated based on site-specific speciation
N ₂ O Annual Emission Rate =	0 TPY	$= A_{Em} * S * CONC_{N_2O}$
3. CH₄ Emission Rate Calculations		
CH ₄ Concentration $CONC_{CH_4}$	0 wt%	Calculated based on site-specific speciation
CH ₄ Annual Emission Rate =	0 TPY	$= A_{Em} * S * CONC_{CH_4}$
4. CO₂e Emission Rate Calculations		
CO ₂ CO ₂ e Factor Fe_{CO_2}	1 ton _{CO2} /ton _{CO2e}	40 CFR 98, Table A-1
N ₂ O CO ₂ e Factor Fe_{N_2O}	310 ton _{N2O} /ton _{CO2e}	40 CFR 98, Table A-1
CH ₄ CO ₂ e Factor Fe_{CH_4}	21 ton _{CH4} /ton _{CO2e}	40 CFR 98, Table A-1
CO ₂ e Annual Emission Rate =	0 TPY	$= \Sigma (TPY * Fe_i)$

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

ATTACHMENT 2
Updated Process Flow Diagram



- Ancillary Sources**
- Utilities (EPN: HRSG5)
 - Fugitive Components (EPN: BOPXXFUG)
 - Diesel Engines (EPNs: DIESELXX01, DIESELXX02, DIESELXX03, DIESELFW1 and DIESELFW2)

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Drawing:	PFD.dwg
Revision #:	1
Date:	October 2012
Project #:	55-2-24

FIGURE 2-1
Block Flow Diagram
ExxonMobil Chemical Company
Ethylene Expansion Project

ATTACHMENT 3
John Zink Company LRGO Test Data

<p align="center">RECORD OF COMMUNICATION</p>	<p align="center"> <input type="checkbox"/> Phone Call <input type="checkbox"/> Discussion <input type="checkbox"/> Field Trip <input type="checkbox"/> Conference <input checked="" type="checkbox"/> Other (Specify) </p>	
<p>To:</p>	<p>From: Allen Chang/Erica Le Doux, 6PD-R, 5-7541/5-7265</p>	<p>Date: <i>Oct 18, 2012</i> Time:</p>
<p>Subject: Confidential Business Information</p>		
<p>Summary of Communication: <i>Exxon Mobil Baytown GHG Application</i> <i>John Zink Company LRGO TEST</i></p>		
<p>Conclusions, Actions Taken, or Required:</p>		

ATTACHMENT 4

Table 3-2

Proposed Work Practice Standards and Operating Limits

ExxonMobil Chemical Company
Table 3-2
Work Practice Standards and Operational Limitations Table

Date: October 2012		Site Name: Baytown Olefins Plant	
Company Name: ExxonMobil Chemical Company		Project: Ethylene Expansion	
Air Contaminant Data			
Emission Point			
EPN	Name	Emission Unit Work Practice Standard, Operational Requirement, or Monitoring	
XXAF01-ST through XXHF01-ST	XXA through XXHF Furnace Combustion Vent	Consume pipeline quality natural gas, or a fuel with a lower carbon content, as fuel to the furnace section	
		Maintain the furnace exhaust stack temperature ≤ 325 °F during online operation (furnace producing ethylene) on a 365-day rolling average basis	
		Maintain furnace exhaust stack CO ≤ 50 ppmv @ 3% O2 during online operation on a 12-month rolling average basis	
		Monitor fuel gas composition with a fuel gas analyzer daily with an analyzer that meets the requirements of 40 CFR 98.244(b)(4)	
		Calibrate and perform preventative maintenance checks of the continuous oxygen and carbon monoxide stack monitors per 40 CFR 60 Appendix B4 every quarter	
		Calibrate and perform preventative maintenance checks of the fuel gas flow meter per the requirements of 40 CFR 98.33(i) and quality assurance requirements of 40 CFR 98.33(i)(2) & (3)	
XXAB-DEC through XXGH-DEC	XXA/B through XXG/H Furnace Decoke Vent	Perform and maintain records of online burner inspections when indicated by CO levels >100 ppmv @ 3% oxygen for a one-hour average and during planned shutdowns	
		Maintain furnace exhaust stack CO ≤ 50 ppmv @ 3% O2 during online operation (furnace producing ethylene) on a 12-month rolling average basis	
FLAREXX1 and FLAREXX2	Staged Flare System	Maintain a minimum heating value and maximum exit velocity that meets 40 CFR § 60.18 requirements for the routine streams routed to the elevated flare including the assist gas flow	
		Continuously monitor and maintain a minimum heating value of 1,000 Btu/scf of the waste gas (adjusted for hydrogen) routed to the multi-point ground flare system to ensure the intermittent stream is combustible; however, if a lower heating value limit can be demonstrated to achieve the same level of combustion efficiency, then this lower limit will be implemented	
		Continuously monitor the flow rate to the multi-point ground flare to demonstrate that flow routed to the multi-point ground flare system exceeds 4 psig; however, if a lower pressure can be demonstrated to achieve the same level of combustion efficiency, then this lower limit will be implemented	
		Continuously monitor the composition of the waste gas contained in the flare system header and record the heating value of the flare system header through an online analyzer located on the common flare header, sufficiently upstream of the diverting headers to the elevated flare and the multi-point flare, calibrated and maintained at least annually	
		Continuously monitor and record the flow to the elevated flare through a flow monitoring system	
		Continuously monitor the steam flow to the elevated flare through a flow monitoring system and record the steam to hydrocarbon ratio	
		Continuously monitor FLAREXX1 for flame presence	
		Continuously monitor the staged flare system pilots for presence of flame	
BOPXXFUG	Fugitives	Conduct daily as-observed AVO inspection for piping components in non-VOC natural gas service	
		Maintain 28 VIHP with CNTQ LDAR program for piping components in VOC service	

ExxonMobil Chemical Company
 Table 3-2
 Work Practice Standards and Operational Limitations Table

Emission Point		Air Contaminant Data
EPN	Name	Emission Unit Work Practice Standard, Operational Requirement, or Monitoring
HRSG05	HRSG05 Duct Burners	Consume pipeline quality natural gas, or a fuel with a lower carbon content, as fuel to the duct burners
		Maintain a minimum thermal efficiency $\geq 70\%$ on a 12-month rolling average
		Maintain exhaust stack CO concentration ≤ 7.4 ppmvd @ 15% O ₂ on a 12-month rolling average
		Perform and maintain records of online burner inspections when indicated by CO levels >100 ppmv @ 15% oxygen for a one-hour average and during planned shutdowns
		Monitor fuel gas composition with a fuel gas analyzer daily with an analyzer that meets the requirements of 40 CFR 98.244(b)(4)
		Calibrate and perform preventative maintenance checks of the continuous carbon monoxide stack monitors per 40 CFR 60 Appendix B4 every quarter
		Calibrate and perform preventative maintenance checks of the fuel gas flow meter per the requirements of 40 CFR 98.33(i) and quality assurance requirements of 40 CFR 98.33(i)(2) & (3)
	Calculate and record the thermal efficiency of HRSG05 monthly	
DIESELXX01, DIESELXX02, and DIESELXX03	Backup Generator Engines	Maintain intermittent and infrequent use or less than 120 hours of operation for testing and maintenance annually
DIESELXFW1 and DIESELFW2	Firewater Booster Pump Engines	Maintain intermittent and infrequent use of less than 120 hours of operation for testing and maintenance annually
ACETCONVXX	Acetylene Converter Regeneration Vent	Maintain a molar ratio above 0.9 mole of hydrogen per mole of acetylene during periods of normal operation, excluding start-up and shutdown, of the acetylene converters on a 365-day rolling average basis
		Calculate as a daily average the molar ratio of hydrogen to acetylene based on online analyzer analysis of the feed streams to the acetylene converters during periods of normal operation, excluding start-up and shutdown