**ExxonMobil Chemical Company**
5000 Bayway Drive
P.O. Box 4004
Baytown, Texas 77522-4004

ExxonMobil
Chemical

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

Benjamin M. Hurst
Air Advisor

Enclosures

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

**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 $CO_2$e 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.*

***<u>Acetylene Converter Regeneration Vent</u>***

*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 $CO_2$ and trace amounts of $N_2O$ and $CH_4$, are vented to the atmosphere through the Acetylene Converter Regeneration Vent (EPN: ACETCONVXX).*

***Emissions Calculations***

*$CO_2$ 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 $CO_2$.*

*$CH_4$ and $N_2O$ 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 $CH_4$ and $N_2O$ emissions were*

*calculated by Equation Y-9 and Y-10, respectively for $CH_4$ and $N_2O$, using the emission factors for coal and coke from 40 CFR 98 Subpart C Table C-2 and the $CO_2$ 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 $CO_2e$ emissions from estimated emissions of $CO_2$, $CH_4$, and $N_2O$ by multiplying the individual GHG pollutant rates by their applicable GWP.*

*Detailed calculations for the acetylene converter regeneration vent are contained in Attachment 1 to this letter. The proposed allowable emissions of $CO_2$, $CH_4$, $N_2O$, and $CO_2e$ 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 $CO_2e$ emitted from the acetylene converter regeneration vent is estimated to be 0.04% of the total GHG emissions for the proposed project and $CO_2$ emissions account for over 99% of the total $CO_2e$ emissions from this emission source. This GHG BACT analysis is therefore focused on controlling $CO_2$ 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 $CO_2$ 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 $CO_2$ 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***

*$CO_2$ 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.*

*$CH_4$ and $N_2O$ 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 $CO_2e$ emissions from estimated emissions of $CO_2$, $CH_4$, and $N_2O$ by multiplying the individual GHG pollutant rates by their applicable GWP.*

*Detailed calculations for this determination are contained in Attachment 1 to this letter. The proposed allowable emissions of $CO_2$, $CH_4$, $N_2O$, and $CO_2e$ 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 $CH_4$, $CO_2$, and $N_2O$. In addition, the $CO_2$ emissions account for 99% of the $CO_2e$ emissions from this source and so the following GHG BACT analysis is focused on $CO_2$.*

### ***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 $CO_2$ 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 $CO_2$ emissions two-an-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 $CO_2$ 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:*

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

*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 source*[1].

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

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

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

*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 USEPA[2]. 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 Zink[3],*

> *"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. Aloke 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. Aloke 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 | Value[6] | 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** | **30,612[8]** | |
| **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 $CO_2$ and CO, where $CO_2$ 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 be 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 $CO_2$ 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 $CO_2$ 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 $CO_2$ 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 states[9]:*

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

*ExxonMobil does not 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 $CO_2$ from a low pressure, low $CO_2$ concentration flue gas has been demonstrated at a scale and level of reliability necessary for application in a compliance-based scenario. The proposed project, with its numerous emission points and low $CO_2$ concentration, does not meet the criteria established in the above paragraph, nor does it meet any reasonable definition of BACT because CCS has not been demonstrated as an "available" and "applicable" technology for 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 $CO_2$ streams since the proposed project will construct eight separate sources that will emit very low-purity $CO_2$ streams. The industrial facilities cited in the above USEPA example are similar to each other in that each has a limited number of stacks and the purity of the $CO_2$ for most is in the range of 65% (versus ~ 8 % for a 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 $CO_2$ 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 $CO_2$ source gas characteristics are evaluated. CCS is not applicable to steam cracking units because of the low purity $CO_2$-containing streams emitted from multiple stacks across the facility.*

*While specific component CCS technologies exist and have been in use for decades, integrated CCS facilities at the necessary scale for a 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.*

<u>*Carbon Capture*</u>

*While several technologies for the post-combustion capture of low-pressure, low-concentration $CO_2$ may be in development, none have been demonstrated at the scale of the proposed project nor for sources at natural gas fired facilities. Carbon capture for the proposed project would require FOAK technology application that is further complicated by the numerous emission points 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 Storage[10]:*

> *"Current technologies could be used to capture $CO_2$ from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the $CO_2$ capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."*

*Recovery and purification of $CO_2$ from the furnace flue gas would require significant additional processing to achieve the necessary $CO_2$ 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% $CO_2$ in the stack gas on an average annual basis, and would have to be purified and dried to a purity of over 98%. The stream would also require complex cooling systems prior to separation, compression, and transport. Therefore, the recovery and purification of $CO_2$ from the stack gases would necessitate significant additional processing, including energy and cooling water, and environmental/air quality penalties, to achieve the necessary $CO_2$ concentration for effective storage.*

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

*Transport*

*Once the $CO_2$ is supercritical, it must be transported to a suitable site for storage or sequestration. Transport via pipeline is the only feasible transportation method for $CO_2$ recovered from BOP due to the volumes involved. There is only one $CO_2$ 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 $CO_2$ from the proposed project, if a pipeline were to be constructed, however, for the purposes of the economic analysis, it has been assumed that a contract would be secured from Denbury Resources and all recovered $CO_2$ from the proposed project would be accepted into the Green Pipeline.*

*Storage*

*Once the $CO_2$ is captured, it must be stored in a stable and secure reservoir or geologic formation that is not susceptible to acidic erosion. While a case specific evaluation has not been conducted, it is likely suitable storage reservoirs could be found within a reasonable proximity to 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 $CO_2$ 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 $CO_2$ from the exhaust gas. The Furnace Section $CO_2$ Capture Plant was specified to accept 1,350 tons of total furnace exhaust gas per hour to remove 92 tons of $CO_2$ 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 $CO_2$ Capture Plant; however, this utility plant would generate its own GHG emissions. The CCS design therefore includes capture of $CO_2$ from the furnace exhaust stacks as well as the additional $CO_2$ 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 $CO_2$ Capture Plant was designed to accept 380 tons of utility plant exhaust gas flow per hour to remove approximately 26 tons of $CO_2$ per hour in an additional amine absorber located near the utility plant emission sources.*

*Amine regeneration and $CO_2$ compression would be centrally located to receive the concentrated rich amine streams from the Furnace Section and Utility Plant $CO_2$ 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 $CO_2$ 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 $CO_2$. The cost estimates for transport and the liability estimate associated with storage were based on the Department of Energy's National Energy Technology Laboratory study "Estimating Carbon Dioxide Transport and Storage Costs", which was recently completed in 2010.*

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

*As shown in Table 4-1, carbon capture for the proposed project is estimated to cost $245.70 per ton of $CO_2$ avoided or $198,400,000 annually to avoid ~90% of the $CO_2$ 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**

| Cost Type | Units[11] | Cost (millions $) |
|---|---|---|
| **Carbon Capture Plants - Capital and Operating Expense Estimation** | | |
| $CO_2$ Compressor and Intercoolers | $ (millions) | 90.6 |
| Amine Absorber Systems | $ (millions) | 200.0 |
| $CO_2$ Regeneration/Purification System | $ (millions) | 127.1 |
| Blower, Piping, and Ducting | $ (millions) | 63.8 |
| **Utility Plant - Capital and Operating Expense Estimation** | | |
| New Utility Plant – Boiler, Boiler Feed Water Treatment and Blower | $ (millions) | 76.2 |
| Cooling Tower, Utilities Header and Piping | $ (millions) | 177.6 |
| Fuel, Utilities, Amine | $ (millions) / yr | 58.6 |
| **Total Expense Estimation** | | |
| Operating Expense | $ / Ton $CO_2$ Avoided | 72.6 |
| Capital Expense | $ / Ton $CO_2$ Avoided | 173.1 |
| Total | $ / Ton $CO_2$ Avoided | 245.7 |

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

### *Table 4-2 Economic Analysis for $CO_2$ Transport*[12]

| 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 $CO_2$ Avoided*** | | | |
| *Total Cost* | *\$ / Ton $CO_2$ Avoided* | *6.4* | |

*The total estimated cost for $CO_2$ transport is \$5,200,000 per year or \$6.4 per ton of $CO_2$ avoided. This cost is for an eight-inch diameter pipeline 30 miles in length to transport supercritical $CO_2$ 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 $CO_2$ Emissions* | *Cost (\$ per ton of $CO_2$ Avoided)* | *Tons of $CO_2$ Avoided per Year*[14] | *Total Annualized Cost*[15] *(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 $CO_2$ generated by the proposed project, capturing and compressing $CO_2$ generated by the $CO_2$ capture equipment, transporting supercritical $CO_2$ 30 miles, and providing liability coverage for storage of the project's $CO_2$ is estimated at \$253.3 per ton of $CO_2$ 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 $CO_2$ emissions in some limited specific industries, it is not an available or applicable technology for steam cracking furnaces due to the low pressure, low $CO_2$ concentration streams that are distributed across multiple sources and the relatively small scale in comparison to a power plant. Based on the aforementioned technological and environmental challenges and the extraordinarily high annualized cost for capture, transport, and storage of $CO_2$, CCS as a combined technology is not considered technically, environmentally, or economically feasible for reducing GHG emissions from the proposed project. CCS is eliminated as a potential control option in the BACT analysis for $CO_2$ emissions from the proposed project.*

8. On page 4-10 of the permit application in the entitled, Decoking Activities, the application identified two potential practices that are technically feasible for $CO_2$ 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 $CO_2$ 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 $CO_2$ from the proposed project and will incorporate the entire flow into its operations. Storage costs are therefore estimated to consist of liability, which is \$5,000,000 per the DOE/NETL 2010 report. 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 $CO_2$e emission calculations for in the decoking emissions calculations. How was the mole ratio of $CO_2$/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 $CO_2$ during the decoke process. A molar ratio of 75/25 was initially assumed for $CO_2$/CO, however, for purposes of this GHG permit application, a conservative assumption of full conversion of the burned coke to $CO_2$ 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 | | | | | |
| EPN | FIN | Name | Component or Air Contaminant Name | GHG Emission Rate (ton/yr) | $CO_2e$ Emission Rate (ton/yr)[A] |
| XXAF01-ST | XXAF01 | XXA Furnace Combustion Vent | $CO_2$ | 122,750 | 122,750 |
| | | | $N_2O$ | 2 | 620 |
| | | | $CH_4$ | 6 | 126 |
| XXBF01-ST | XXBF01 | XXB Furnace Combustion Vent | $CO_2$ | 122,750 | 122,750 |
| | | | $N_2O$ | 2 | 620 |
| | | | $CH_4$ | 6 | 126 |
| XXCF01-ST | XXCF01 | XXC Furnace Combustion Vent | $CO_2$ | 122,750 | 122,750 |
| | | | $N_2O$ | 2 | 620 |
| | | | $CH_4$ | 6 | 126 |
| XXDF01-ST | XXDF01 | XXD Furnace Combustion Vent | $CO_2$ | 122,750 | 122,750 |
| | | | $N_2O$ | 2 | 620 |
| | | | $CH_4$ | 6 | 126 |
| XXEF01-ST | XXEF01 | XXE Furnace Combustion Vent | $CO_2$ | 122,750 | 122,750 |
| | | | $N_2O$ | 2 | 620 |
| | | | $CH_4$ | 6 | 126 |
| XXFF01-ST | XXFF01 | XXF Furnace Combustion Vent | $CO_2$ | 122,750 | 122,750 |
| | | | $N_2O$ | 2 | 620 |
| | | | $CH_4$ | 6 | 126 |
| XXGF01-ST | XXGF01 | XXG Furnace Combustion Vent | $CO_2$ | 122,750 | 122,750 |
| | | | $N_2O$ | 2 | 620 |
| | | | $CH_4$ | 6 | 126 |
| XXHF01-ST | XXHF01 | XXH Furnace Combustion Vent | $CO_2$ | 122,750 | 122,750 |
| | | | $N_2O$ | 2 | 620 |
| | | | $CH_4$ | 6 | 126 |
| XXAB-DEC | XXABDEC | XXA/B Furnace Decoke Vent | $CO_2$ | 199 | 199 |
| | | | $N_2O$ | 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 | | | | | |
| EPN | FIN | Name | Component or Air Contaminant Name | GHG Emission Rate (ton/yr) | $CO_2$e Emission Rate (ton/yr)[A] |
| XXCD-DEC | XXCDDEC | XXC/D Furnace Decoke Vent | $CO_2$ | 199 | 199 |
| | | | $N_2O$ | 1 | 310 |
| | | | $CH_4$ | 1 | 21 |
| XXEF-DEC | XXEFDEC | XXE/F Furnace Decoke Vent | $CO_2$ | 199 | 199 |
| | | | $N_2O$ | 1 | 310 |
| | | | $CH_4$ | 1 | 21 |
| XXGH-DEC | XXGHDEC | XXG/H Furnace Decoke Vent | $CO_2$ | 199 | 199 |
| | | | $N_2O$ | 1 | 310 |
| | | | $CH_4$ | 1 | 21 |
| FLAREXX1 and FLAREXX2 | FLAREXX1 and FLAREXX2 | Staged Flare System | $CO_2$ | 86,574 | 86,574 |
| | | | $N_2O$ | 5 | 1,550 |
| | | | $CH_4$ | 115 | 2,415 |
| BOPXXFUG | BOPXXAREA | Fugitives | $CO_2$ | NA[B] | NA[B] |
| | | | $N_2O$ | NA[B] | NA[B] |
| | | | $CH_4$ | NA[B] | NA[B] |
| HRSG05 | HRSG05 | Duct Burners | $CO_2$ | 397,231 | 397,231 |
| | | | $N_2O$ | 1 | 310 |
| | | | $CH_4$ | 8 | 168 |
| DIESELXX01 DIESELXX02 DIESELXX03 | DIESELXX01 DIESELXX02 DIESELXX03 | Backup Generator Engines | $CO_2$ | 223 | 223 |
| | | | $N_2O$ | 1 | 310 |
| | | | $CH_4$ | 1 | 21 |
| DIESELXXFW1 DIESELXXFW2 | DIESELXXFW1 DIESELXXFW2 | Firewater Booster Pump Engines | $CO_2$ | 67 | 67 |
| | | | $N_2O$ | 1 | 310 |
| | | | $CH_4$ | 1 | 21 |
| ACETCONVXX | ACETCONVXX | Acetylene Converter Regeneration Vent | $CO_2$ | 25 | 25 |
| | | | $N_2O$ | 1 | 310 |
| | | | $CH_4$ | 1 | 21 |
| Proposed Project Compliance Totals | | | $CO_2$ | 1,466,916 | 1,466,916 |
| | | | $N_2O$ | 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.

EPN = Emission Point Number
FIN = Facility Identification Number

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

| 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 shal

| 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. $CO_2$ 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. $N_2O$ Annual Emission Rate Calculations** | | | |
| **$N_2O$ Furnace Firing NG Emission Rate** | = | **1 TPY** | |
| **$N_2O$ Furnace Firing Blended FG Emission Rate** | = | **1 TPY** | |
| **$N_2O$ Annual Emission Rate** | = | **2 TPY** | Sum of annual $N_2O$ emissions from all streams |
| **3. $CH_4$ 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. $CO_2e$ Emission Rate Calculations** | | | |
| $CO_2$ $CO_2e$ Factor $Fe_{CO2}$ | | 1 $ton_{CO2}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $N_2O$ $CO_2e$ Factor $Fe_{N2O}$ | | 310 $ton_{N2O}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $CH_4$ $CO_2e$ Factor $Fe_{CH4}$ | | 21 $ton_{CH4}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| **$CO_2e$ Annual Emission Rate** | = | **123,496 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.

| 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. $CO_2$ Emission Rate Calculations** | | | |
| **$CO_2$ Annual Emission Rate** | = | **4,602 TPY** | $= MW_{CO2}/MW_{Carbon} * Q_V * F_{CC} * M_V / V_{MS}$ / 2000 lb/ton<br>Equation C-5 |
| **3. $N_2O$ Emission Rate Calculations** | | | |
| $N_2O$ Emission Factor | $F_{N2O}$ | 1.0E-04 kg/MMBtu | 40 CFR 98, Table C-2 |
| **$N_2O$ Annual Emission Rate** | = | **1 TPY** | $= H * F_{N2O}$ / .4536 kg/lb / 2000 lb/ton<br>Equation C-8 |
| **4. $CH_4$ Emission Rate Calculations** | | | |
| $CH_4$ Emission Factor | $F_{CH4}$ | 1.0E-03 kg/MMBtu | 40 CFR 98, Table C-2 |
| **$CH_4$ Annual Emission Rate** | = | **1 TPY** | $= H * F_{CH4}$ / .4536 kg/lb / 2000 lb/ton<br>Equation C-8 |
| **5. $CO_2e$ Emission Rate Calculations** | | | |
| $CO_2$ $CO_2e$ Factor | $Fe_{CO2}$ | 1 $ton_{CO2}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $N_2O$ $CO_2e$ Factor | $Fe_{N2O}$ | 310 $ton_{N2O}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $CH_4$ $CO_2e$ Factor | $Fe_{CH4}$ | 21 $ton_{CH4}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| **$CO_2e$ Annual Emission Rate** | = | **4,933 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.
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. $CO_2$ Emission Rate Calculations** | | | |
| **$CO_2$ Annual Emission Rate** | = | **118,148 TPY** | $= MW_{CO2}/MW_{Carbon} * Q_V * F_{CC} * M_V / V_{MS}$ / 2000 lb/ton<br>Equation C-5 |
| **3. $N_2O$ Emission Rate Calculations** | | | |
| $N_2O$ Emission Factor | $F_{N2O}$ | 1.0E-04 kg/MMBtu | 40 CFR 98, Table C-2 |
| **$N_2O$ Annual Emission Rate** | = | **1 TPY** | $= H * F_{N2O}$ / .4536 kg/lb / 2000 lb/ton<br>Equation C-8 |
| **4. $CH_4$ Emission Rate Calculations** | | | |
| $CH_4$ Emission Factor | $F_{CH4}$ | 1.0E-03 kg/MMBtu | 40 CFR 98, Table C-2 |
| **$CH_4$ Annual Emission Rate** | = | **5 TPY** | $= H * F_{CH4}$ / .4536 kg/lb / 2000 lb/ton<br>Equation C-8 |
| **5. $CO_2e$ Emission Rate Calculations** | | | |
| $CO_2$ $CO_2e$ Factor | $Fe_{CO2}$ | 1 $ton_{CO2}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $N_2O$ $CO_2e$ Factor | $Fe_{N2O}$ | 310 $ton_{N2O}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $CH_4$ $CO_2e$ Factor | $Fe_{CH4}$ | 21 $ton_{CH4}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| **$CO_2e$ Annual Emission Rate** | = | **118,563 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.
The most conservative basis was used to calculate the furnace firing emission by not accounting for reduced firing rates during decoke operations.

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

| Parameter Name & Variable | | Value & Units | Basis/Calculation/Notes |
|---|---|---|---|
| **1. General Values and Calculations** | | | |
| 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 | $= C_A * C_{OX} * 2,000$ lb/yr |
| **2. $CO_2$ 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 lb carbon / lb coke | Conservative estimate |
| **$CO_2$ Annual Emission Rate** | = | **199 TPY** | $=C_{OX,A} * CC_{Coke} * MW_{CO2} / MW_{Carbon}$ Equation Y-11 |
| **2. $N_2O$ Emission Rate Calculations** | | | |
| $N_2O$ Emission Factor | $F_{N2O}$ | 6.E-04 kg/MMBtu | 40 CFR 98, Table C-2 |
| **$N_2O$ Annual Emission Rate** | = | **1 TPY** | $= CO_2$ tpy $* F_{N2O} / F_{CO2}$ Equation Y-9 |
| **2. $CH_4$ 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** | $= CO_2$ tpy $* F_{CH4} / F_{CO2}$ Equation Y-9 |
| **3. $CO_2e$ Emission Rate Calculations** | | | |
| $CO_2$ $CO_2e$ Factor | $Fe_{CO2}$ | 1 $ton_{CO2}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $N_2O$ $CO_2e$ Factor | $Fe_{N2O}$ | 310 $ton_{N2O}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $CH_4$ $CO_2e$ Factor | $Fe_{CH4}$ | 21 $ton_{CH4}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| **$CO_2e$ Annual Emission Rate** | = | **530 TPY** | $= \Sigma$ (TPY $* Fe_x$) |

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

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

| Parameter Name & Variable | | Value & Units | Basis/Calculation/Notes |
|---|---|---|---|
| **1. $CO_2$ 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. $N_2O$ Emission Rate Calculations** | | | |
| **$N_2O$ Routine Flaring Annual Emission Rate** | = | 1 TPY | |
| $N_2O$ Intermittent Flaring Annual Emission Rate | = | 1 TPY | |
| **$N_2O$ Pilot Gas Annual Emission Rate** | = | 3 TPY | |
| **$N_2O$ Annual Emission Rate** | = | 5 TPY | Sum of annual $N_2O$ emissions from all streams |
| **3. $CH_4$ Emission Rate Calculations** | | | |
| **$CH_4$ 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. $CO_2e$ Emission Rate Calculations** | | | |
| $CO_2$ $CO_2e$ Factor | $Fe_{CO2}$ | 1 $ton_{CO2}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $N_2O$ $CO_2e$ Factor | $Fe_{N2O}$ | 310 $ton_{N2O}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $CH_4$ $CO_2e$ Factor | $Fe_{CH4}$ | 21 $ton_{CH4}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| **$CO_2e$ Annual Emission Rate** | = | 90,539 TPY | $= \Sigma (TPY * Fe_x)$ |

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

ExxonMobil Chemical Company
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. $CO_2$ Emission Rate Calculations** | | | |
| **$CO_2$ Annual Emission Rate** | **=** | **36,119 TPY** | $= E_F * MW_{CO2} / MW_C * Q_V * 10^6 * M_V / V_{MS} * CC_{gas}$ / 2000 lb/ton<br>Equation Y-1a |
| **3. $N_2O$ Emission Rate Calculations** | | | |
| $N_2O$ Emission Factor | $F_{N2O}$ | 6.0E-04 kg/MMBtu | 40 CFR 98 Subpart Y |
| **$N_2O$ Annual Emission Rate** | **=** | **1 TPY** | $= CO_2$ TPY $* F_{N2O} / F_{CO2}$<br>Equation Y-5 |
| **4. $CH_4$ Emission Rate Calculations** | | | |
| $CH_4$ Emission Factor | $F_{CH4}$ | 3.0E-03 kg/MMBtu | 40 CFR 98 Subpart Y |
| Wt. fraction of carbon in fuel gas from $CH_4$ | $f_{CH4}$ | 0.37 | Calculated from representative stream speciation |
| **$CH_4$ Annual Emission Rate** | **=** | **101 TPY** | $= (CO_2$ TPY $* F_{CH4} / F_{CO2}) + (CO_2$ TPY $* C_F * MW_{CH4}/MW_{CO2} * f_{CH4})$<br>Equation Y-4 |
| **5. $CO_2e$ Emission Rate Calculations** | | | |
| $CO_2$ $CO_2e$ Factor | $Fe_{CO2}$ | 1 $ton_{CO2}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $N_2O$ $CO_2e$ Factor | $Fe_{N2O}$ | 310 $ton_{N2O}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $CH_4$ $CO_2e$ Factor | $Fe_{CH4}$ | 21 $ton_{CH4}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| **$CO_2e$ Annual Emission Rate** | **=** | **38,560 TPY** | $= \Sigma$ (TPY $* Fe_x$) |

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

ExxonMobil Chemical Company
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 | $F_{CO2}$ | 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. $CO_2$ Emission Rate Calculations** | | | |
| **$CO_2$ Annual Emission Rate** | = | **48,497 TPY** | $= E_F * MW_{CO2} / MW_C * Q_V * M_V / V_{MS} * CC_{gas}$ / 2000 lb/ton<br>Equation Y-1a |
| **3. $N_2O$ Emission Rate Calculations** | | | |
| $N_2O$ Emission Factor | $F_{N2O}$ | 6.0E-04 kg/MMBtu | 40 CFR 98 Subpart Y |
| **$N_2O$ Annual Emission Rate** | = | **1 TPY** | $= CO_2$ TPY $* F_{N2O} / F_{CO2}$<br>Equation Y-5 |
| **4. $CH_4$ Emission Rate Calculations** | | | |
| $CH_4$ Emission Factor | $F_{CH4}$ | 3.0E-03 kg/MMBtu | 40 CFR 98 Subpart Y |
| Wt. fraction of carbon in fuel gas from $CH_4$ | $f_{CH4}$ | 0.04 | Calculated from representative stream speciation |
| **$CH_4$ Annual Emission Rate** | = | **4 TPY** | $= (CO_2$ TPY $* F_{CH4} / F_{CO2}) + (CO_2$ TPY $* C_F * MW_{CH4}/MW_{CO2} * f_{CH4})$<br>Equation Y-4 |
| **5. $CO_2e$ Emission Rate Calculations** | | | |
| $CO_2$ $CO_2e$ Factor | $Fe_{CO2}$ | 1 $ton_{CO2}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $N_2O$ $CO_2e$ Factor | $Fe_{N2O}$ | 310 $ton_{N2O}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $CH_4$ $CO_2e$ Factor | $Fe_{CH4}$ | 21 $ton_{CH4}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| **$CO_2e$ Annual Emission Rate** | = | **48,891 TPY** | $= \Sigma$ (TPY $* Fe_x$) |

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

ExxonMobil Chemical Company
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. $CO_2$ 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<br>Equation Y-1a |
| **3. $N_2O$ Emission Rate Calculations** | | | |
| $N_2O$ Emission Factor | $F_{N2O}$ | 6.0E-04 kg/MMBtu | 40 CFR 98 Subpart Y |
| **$N_2O$ Annual Emission Rate** | = | **1 TPY** | = $CO_2$ TPY * $F_{N2O}$ / $F_{CO2}$<br>Equation Y-5 |
| **4. $CH_4$ Emission Rate Calculations** | | | |
| $CH_4$ Emission Factor | $F_{CH4}$ | 3.0E-03 kg/MMBtu | 40 CFR 98 Subpart Y |
| Wt. fraction of carbon in fuel gas from $CH_4$ | $f_{CH4}$ | 0.95 | Calculated from representative stream speciation |
| **$CH_4$ Annual Emission Rate** | = | 2 TPY | = ($CO_2$ TPY * $F_{CH4}$ / $F_{CO2}$) + ($CO_2$ TPY * $C_F$ * $MW_{CH4}$/$MW_{CO2}$ * $f_{CH4}$)<br>Equation Y-4 |
| **5. $CO_2e$ Emission Rate Calculations** | | | |
| $CO_2$ $CO_2e$ Factor | $Fe_{CO2}$ | 1 $ton_{CO2}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $N_2O$ $CO_2e$ Factor | $Fe_{N2O}$ | 310 $ton_{N2O}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $CH_4$ $CO_2e$ Factor | $Fe_{CH4}$ | 21 $ton_{CH4}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| **$CO_2e$ Annual Emission Rate** | = | **504 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 (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. $CO_2$ 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<br>Equation Y-1a |
| **3. $N_2O$ Emission Rate Calculations** | | | |
| $N_2O$ Emission Factor | $F_{N2O}$ | 6.0E-04 kg/MMBtu | 40 CFR 98 Subpart Y |
| **$N_2O$ Annual Emission Rate** | = | **1 TPY** | $= CO_2\ TPY * F_{N2O} / F_{CO2}$<br>Equation Y-5 |
| **4. $CH_4$ Emission Rate Calculations** | | | |
| $CH_4$ Emission Factor | $F_{CH4}$ | 3.0E-03 kg/MMBtu | 40 CFR 98 Subpart Y |
| Wt. fraction of carbon in fuel gas from $CH_4$ | $f_{CH4}$ | 0.01 | Calculated from representative stream speciation |
| **$CH_4$ Annual Emission Rate** | = | **1 TPY** | $= (CO_2\ TPY * F_{CH4} / F_{CO2}) + (CO_2\ TPY * C_F * MW_{CH4}/MW_{CO2} * f_{CH4})$<br>Equation Y-4 |
| **5. $CO_2e$ Emission Rate Calculations** | | | |
| $CO_2$ $CO_2e$ Factor | $Fe_{CO2}$ | 1 $ton_{CO2}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $N_2O$ $CO_2e$ Factor | $Fe_{N2O}$ | 310 $ton_{N2O}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $CH_4$ $CO_2e$ Factor | $Fe_{CH4}$ | 21 $ton_{CH4}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| **$CO_2e$ Annual Emission Rate** | = | **1,225 TPY** | $= \Sigma (TPY * Fe_x)$ |

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

ExxonMobil Chemical Company
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 | $F_{CO2}$ | 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. $CO_2$ Emission Rate Calculations** | | | |
| **$CO_2$ Annual Emission Rate** | = | **912 TPY** | $= 0.98 * MW_{CO2} / MW_C * Q_V * t * M_V / V_{MS} * CC_{gas} / 2000$ lb/ton<br>Equation Y-1a |
| **3. $N_2O$ Emission Rate Calculations** | | | |
| $N_2O$ Emission Factor | $F_{N2O}$ | 6.0E-04 kg/MMBtu | 40 CFR 98 Subpart Y |
| **$N_2O$ Annual Emission Rate** | = | **1 TPY** | $= CO_2$ TPY $* F_{N2O} / F_{CO2}$<br>Equation Y-5 |
| **4. $CH_4$ Emission Rate Calculations** | | | |
| $CH_4$ Emission Factor | $F_{CH4}$ | 3.0E-03 kg/MMBtu | 40 CFR 98 Subpart Y |
| Wt. fraction of carbon in fuel gas from $CH_4$ | $f_{CH4}$ | 0.95 | Calculated from representative stream speciation |
| **$CH_4$ Annual Emission Rate** | = | **7 TPY** | $= (CO_2$ TPY $* F_{CH4} / F_{CO2}) + (CO_2$ TPY $* C_F * MW_{CH4}/MW_{CO2} * f_{CH4})$<br>Equation Y-4 |
| **5. $CO_2e$ Emission Rate Calculations** | | | |
| $CO_2$ $CO_2e$ Factor | $Fe_{CO2}$ | 1 $ton_{CO2}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $N_2O$ $CO_2e$ Factor | $Fe_{N2O}$ | 310 $ton_{N2O}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $CH_4$ $CO_2e$ Factor | $Fe_{CH4}$ | 21 $ton_{CH4}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| **$CO_2e$ Annual Emission Rate** | = | **1,369 TPY** | $= \Sigma$ (TPY $* Fe_x$) |

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

ExxonMobil Chemical Company
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 | $Fug_{Total}$ | **58 TPY** | See Table below |
| **2. $CO_2$ Emission Rate Calculations** | | | |
| $CO_2$ Content | $CO_2$ wt% | 0 wt% | |
| **$CO_2$ Annual Emission Rate** | = | **0 TPY** | $= Fug_{Total} * CO_2$ wt% |
| **3. $CH_4$ Emission Rate Calculations** | | | |
| $CH_4$ content | $CH_4$ wt% | 5% wt% | Calculated based on site-specific speciation |
| **$CH_4$ Annual Emission Rate** | = | **1 TPY** | $= Fug_{Total} * CH_4$ wt% |
| **4. $CO_2e$ Emission Rate Calculations** | | | |
| $CO_2$ $CO_2e$ Factor | $Fe_{CO2}$ | 1 $ton_{CO2}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $CH_4$ $CO_2e$ Factor | $Fe_{CH4}$ | 21 $ton_{CH4}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| **$CO_2e$ Annual Emission Rate** | = | **21 TPY** | $= \Sigma (TPY * Fe_x)$ |

**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. $CO_2$ Emission Rate Calculations** | | | |
| **$CO_2$ Annual Emission Rate** | = | **397,231 TPY** | $= MW_{CO2}/MW_{Carbon} * Q_V * 10^6 * F_{CC} * M_V / V_{MS}$ / 2000 lb/ton<br>Equation C-5 |
| **3. $N_2O$ Emission Rate Calculations** | | | |
| $N_2O$ Emission Factor | $F_{N2O}$ | 1.0E-04 kg/MMBtu | 40 CFR 98, Table C-2 |
| **$N_2O$ Annual Emission Rate** | = | **1 TPY** | $= H * F_{N2O}$ / 0.4536 kg/lb / 2000 lb/ton<br>Equation C-8 |
| **4. $CH_4$ Emission Rate Calculations** | | | |
| $CH_4$ Emission Factor | $F_{CH4}$ | 1.0E-03 kg/MMBtu | 40 CFR 98, Table C-2 |
| **$CH_4$ Annual Emission Rate** | = | **8 TPY** | $= H * F_{CH4}$ / 0.4536 kg/lb / 2000 lb/ton<br>Equation C-8 |
| **5. $CO_2e$ Emission Rate Calculations** | | | |
| $CO_2$ $CO_2e$ Factor | $Fe_{CO2}$ | 1 $ton_{CO2}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $N_2O$ $CO_2e$ Factor | $Fe_{N2O}$ | 310 $ton_{N2O}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $CH_4$ $CO_2e$ Factor | $Fe_{CH4}$ | 21 $ton_{CH4}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| **$CO_2e$ Annual Emission Rate** | = | **397,709 TPY** | $= \Sigma (TPY * Fe_x)$ |

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

ExxonMobil Chemical Company
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. $CO_2$ Emission Rate Calculations** | | | |
| $CO_2$ Emission Factor | $F_{CO2}$ | 73.96 kg/MMBtu | 40 CFR 98, Table C-1 |
| **$CO_2$ Annual Emission Rate** | = | **223 TPY** | $=H_A * F_{CO2}$ * 2.205 lb/kg / 2000 lb/ton<br>Equation C-1 |
| **3. $N_2O$ Emission Rate Calculations** | | | |
| $N_2O$ Emission Factor | $F_{N2O}$ | 6.0E-04 kg/MMBtu | 40 CFR 98, Table C-2 |
| **$N_2O$ Annual Emission Rate** | = | **1 TPY** | $=H_A * F_{N2O}$ * 2.205 lb/kg / 2000 lb/ton<br>Equation C-8b |
| **4. $CH_4$ Emission Rate Calculations** | | | |
| $CH_4$ Emission Factor | $F_{CH4}$ | 3.0E-03 kg/MMBtu | 40 CFR 98, Table C-2 |
| **$CH_4$ Annual Emission Rate** | = | **1 TPY** | $=H_A * F_{CH4}$ * 2.205 lb/kg / 2000 lb/ton<br>Equation C-8b |
| **5. $CO_2e$ Emission Rate Calculations** | | | |
| $CO_2$ $CO_2e$ Factor | $Fe_{CO2}$ | 1 $ton_{CO2}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $N_2O$ $CO_2e$ Factor | $Fe_{N2O}$ | 310 $ton_{N2O}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $CH_4$ $CO_2e$ Factor | $Fe_{CH4}$ | 21 $ton_{CH4}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| **$CO_2e$ Annual Emission Rate** | = | **554 TPY** | $= \Sigma$ (TPY * $Fe_x$) |

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

ExxonMobil Chemical Company
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. $CO_2$ Emission Rate Calculations** | | | |
| $CO_2$ Emission Factor | $F_{CO2}$ | 73.96 kg/MMBtu | 40 CFR 98, Table C-1 |
| **$CO_2$ Annual Emission Rate** | = | **67 TPY** | $=H_A * F_{CO2} * 2.205$ lb/kg / 2000 lb/ton<br>Equation C-1 |
| **3. $N_2O$ Emission Rate Calculations** | | | |
| $N_2O$ Emission Factor | $F_{N2O}$ | 6.0E-04 kg/MMBtu | 40 CFR 98, Table C-2 |
| **$N_2O$ Annual Emission Rate** | = | **1 TPY** | $=H_A * F_{N2O} * 2.205$ lb/kg / 2000 lb/ton<br>Equation C-8b |
| **4. $CH_4$ Emission Rate Calculations** | | | |
| $CH_4$ Emission Factor | $F_{CH4}$ | 3.0E-03 kg/MMBtu | 40 CFR 98, Table C-2 |
| **$CH_4$ Annual Emission Rate** | = | **1 TPY** | $=H_A * F_{CH4} * 2.205$ lb/kg / 2000 lb/ton<br>Equation C-8b |
| **5. $CO_2e$ Emission Rate Calculations** | | | |
| $CO_2$ $CO_2e$ Factor | $Fe_{CO2}$ | 1 $ton_{CO2}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $N_2O$ $CO_2e$ Factor | $Fe_{N2O}$ | 310 $ton_{N2O}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $CH_4$ $CO_2e$ Factor | $Fe_{CH4}$ | 21 $ton_{CH4}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| **$CO_2e$ Annual Emission Rate** | = | **398 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.

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 | $= C_A * C_{OX} * 2{,}000$ lb/yr |
| **2. $CO_2$ 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. $N_2O$ Emission Rate Calculations** | | | |
| $N_2O$ Emission Factor | $F_{N2O}$ | 6.E-04 kg/MMBtu | 40 CFR 98, Table C-2 |
| **$N_2O$ Annual Emission Rate** | = | **1 TPY** | $= CO_2$ tpy $* F_{N2O} / F_{CO2}$ Equation Y-10 |
| **2. $CH_4$ 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** | $= CO_2$ tpy $* F_{CH4} / F_{CO2}$ Equation Y-9 |
| **3. $CO_2e$ Emission Rate Calculations** | | | |
| $CO_2$ $CO_2e$ Factor | $Fe_{CO2}$ | 1 $ton_{CO2}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $N_2O$ $CO_2e$ Factor | $Fe_{N2O}$ | 310 $ton_{N2O}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $CH_4$ $CO_2e$ Factor | $Fe_{CH4}$ | 21 $ton_{CH4}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| **$CO_2e$ Annual Emission Rate** | = | **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.
$CH_4$ or $N_2O$ 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 | $d_{H2O}$ | 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. $CO_2$ Emission Rate Calculations** | | | |
| $CO_2$ Concentration | $CONC_{CO2}$ | 0 ppmw | Calculated based on site-specific speciation |
| **$CO_2$ Annual Emission Rate** | = | **0 TPY** | $= Q_V * 60$ min/hr $* d_{H2O} * CONC_{CO2} / 10^6 * t /$ 2000 lb/ton |
| **3. $N_2O$ Emission Rate Calculations** | | | |
| $N_2O$ Concentration | $CONC_{N2O}$ | 0 ppmw | Calculated based on site-specific speciation |
| **$N_2O$ Annual Emission Rate** | = | **0 TPY** | $= Q_V * 60$ min/hr $* d_{H2O} * CONC_{N2O} / 10^6 * t /$ 2000 lb/ton |
| **3. $CH_4$ Emission Rate Calculations** | | | |
| $CH_4$ Concentration | $CONC_{CH4}$ | 0 ppmw | Calculated based on site-specific speciation |
| **$CH_4$ Annual Emission Rate** | = | **0 TPY** | $= Q_V * 60$ min/hr $* d_{H2O} * CONC_{CH4} / 10^6 * t /$ 2000 lb/ton |
| **4. $CO_2e$ Emission Rate Calculations** | | | |
| $CO_2$ $CO_2e$ Factor | $Fe_{CO2}$ | 1 $ton_{CO2}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $N_2O$ $CO_2e$ Factor | $Fe_{N2O}$ | 310 $ton_{N2O}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $CH_4$ $CO_2e$ Factor | $Fe_{CH4}$ | 21 $ton_{CH4}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| **$CO_2e$ Annual Emission Rate** | = | **0 TPY** | $= \Sigma (TPY * Fe_x)$ |

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

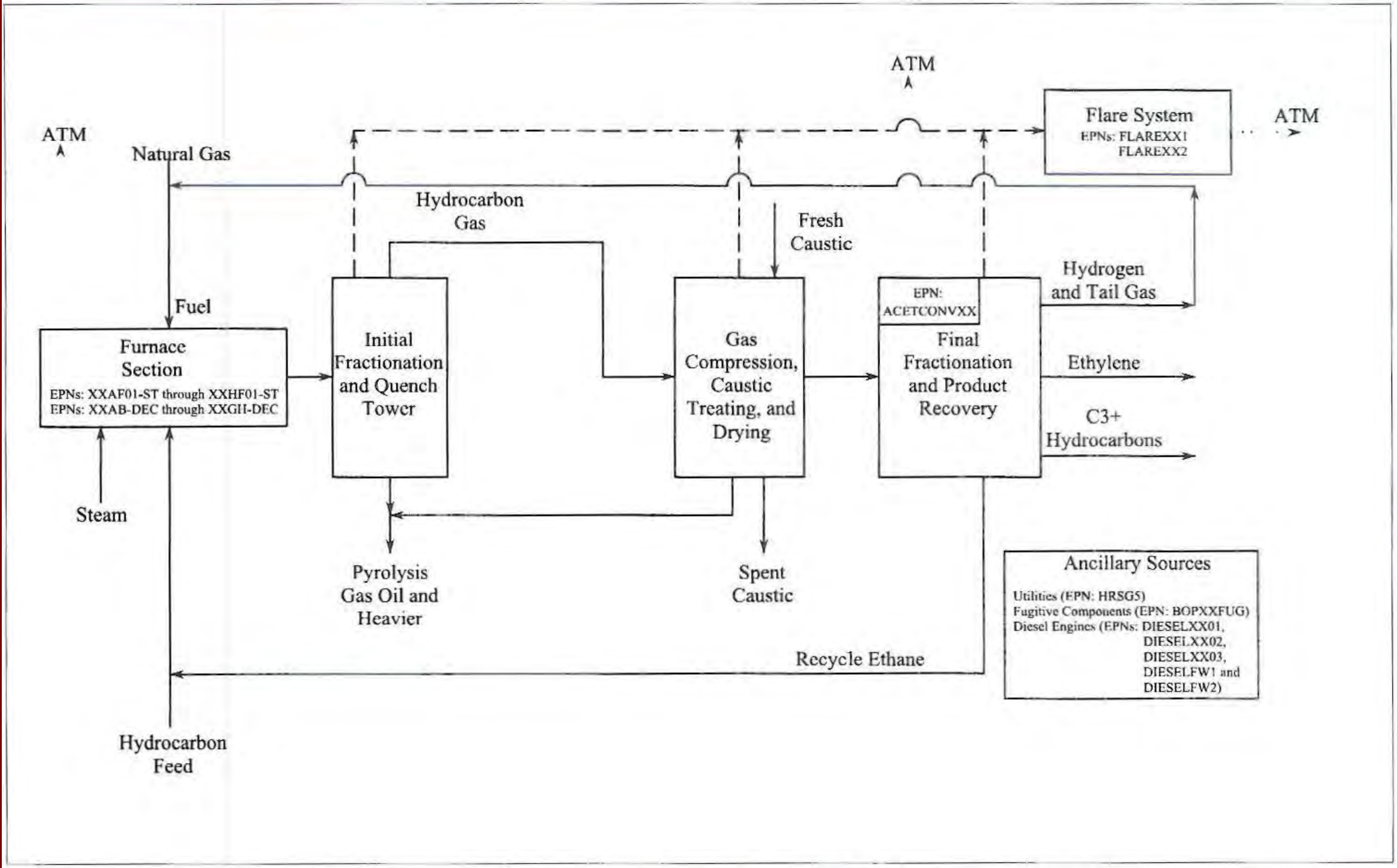
ExxonMobil Chemical Company
Baytown Olefins Plant
Tanks
Greenhouse Gas Emissions Calculations

| 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. $CO_2$ Emission Rate Calculations** | | | |
| $CO_2$ Concentration | $CONC_{CO2}$ | 0 wt% | Calculated based on site-specific speciation |
| **$CO_2$ Annual Emission Rate** | = | **0 TPY** | $= A_{Em} * S * CONC_{CO2}$ |
| **3. $N_2O$ Emission Rate Calculations** | | | |
| $N_2O$ Concentration | $CONC_{N2O}$ | 0 wt% | Calculated based on site-specific speciation |
| **$N_2O$ Annual Emission Rate** | = | **0 TPY** | $= A_{Em} * S * CONC_{N2O}$ |
| **3. $CH_4$ Emission Rate Calculations** | | | |
| $CH_4$ Concentration | $CONC_{CH4}$ | 0 wt% | Calculated based on site-specific speciation |
| **$CH_4$ Annual Emission Rate** | = | **0 TPY** | $= A_{Em} * S * CONC_{CH4}$ |
| **4. $CO_2e$ Emission Rate Calculations** | | | |
| $CO_2$ $CO_2e$ Factor | $Fe_{CO2}$ | 1 $ton_{CO2}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $N_2O$ $CO_2e$ Factor | $Fe_{N2O}$ | 310 $ton_{N2O}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| $CH_4$ $CO_2e$ Factor | $Fe_{CH4}$ | 21 $ton_{CH4}/ton_{CO2e}$ | 40 CFR 98, Table A-1 |
| **$CO_2e$ Annual Emission Rate** | = | **0 TPY** | $= \Sigma (TPY * Fe_i)$ |

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

# ATTTACHMENT 2

## Updated Process Flow Diagram




| | | |
|---|---|---|
| SAGE ENVIRONMENTAL CONSULTING | Drawing: PFD.dwg | FIGURE 2–1 |
| | Revision #: 1 | Block Flow Diagram |
| | Date: October 2012 | ExxonMobil Chemical Company |
| *"Friendly Service, No Surprises!"®* | Project #: 55–2–24 | Ethylene Expansion Project |

# ATTTACHMENT 3

## John Zink Company LRGO Test Data

<table>
<tr><td>RECORD OF<br>COMMUNICATION</td><td colspan="2">_ Phone Call __ Discussion __ Field Trip<br>__ Conference _X_ Other (Specify)</td></tr>
<tr><td>To:</td><td>From: Allen Chang/Erica Le Doux, 6PD-R, 5-7541/5-7265</td><td>Date: Oct 18, 2012<br>Time:</td></tr>
<tr><td colspan="3">Subject: Confidential Business Information</td></tr>
<tr><td colspan="3">Summary of Communication:<br>Exxon Mobil Baytown GHG Application<br>John Zink Company LRGO Test</td></tr>
<tr><td colspan="3">Conclusions, Actions Taken, or Required:</td></tr>
</table>

# ATTTACHMENT 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) |
| | | 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 |
| XXAB-DEC through XXGH-DEC | XXA/B through XXG/H Furnace Decoke Vent | 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 VHP with CNTQ LDAR program for piping components in VOC service |

EPN - Emission Point Number

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

| Air Contaminant Data | | |
|---|---|---|
| **Emission Point** | | |
| **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 ≥ 70% on a 12-month rolling average |
| | | Maintain exhaust stack CO concentration ≤ 7.4 ppmvd @ 15% O2 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 |
| DIESELXXFW1 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 |