From:	Robinson, Jeffrey
To:	Wilson, Aimee; Tomasovic, Brian
Subject:	Fw: ExxonMobil Information
Date:	Friday, September 20, 2013 12:50:05 PM
Attachments:	2013.09.20_PSD-TX-102982-GHG Response.pdf

From: Hurst, Benjamin M <benjamin.m.hurst@exxonmobil.com>
Sent: Friday, September 20, 2013 12:07:24 PM
To: Robinson, Jeffrey; Kovacs, Jeffrey K
Cc: Bass, Margaret S; Rebecca Rentz (rrentz@winstead.com)
Subject: RE: ExxonMobil Information

Jeff

Attached is our response to the additional information requested in your e-mail below. In the attachment, we have included your questions/requests verbatim followed by our responses in blue text. If you have any additional questions, please contact me at (281) 834-6110 or benjamin.m.hurst@exxonmobil.com.

Thank you,

Benjamin M. Hurst
Baytown Olefins Plant
Ph: (281) 834-6110
Email: benjamin.m.hurst@exxonmobil.com

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From: Robinson, Jeffrey [mailto:Robinson.Jeffrey@epa.gov]
Sent: Tuesday, September 17, 2013 12:13 PM
To: Kovacs, Jeffrey K
Cc: Hurst, Benjamin M
Subject: ExxonMobil Information

Jeff:

Below is our additional information request based on our discussion last week and additional EPA internal discussion after our meeting last week:

Sierra Club Comment C(3)(b)(ii) "The Cost Analysis for Carbon Capture and Sequestration is Invalid – Annualized Capital Costs"

- Please provide additional information on how the annualized capital costs for CCS were calculated. In particular, are there any additional specifics you can provide for the use of a 19% capital charge rate.

Sierra Club Comment D "The Draft Permit Fails to Account for Increased Upstream and Downstream Production (Debottlenecking)"

- Please provide a list of affected but unmodified units that will have an increase of GHG emissions due to this project.
- Provide the GHG emissions of affected but unmodified units
- Please provide an analysis to show that affected units are not modified (as defined at 40 CFR 52.21(b)(2)) as a result of this project.
- In particular, please address how the bottoms product from the new deethanizer being utilized as a feed to the existing base plant depropanizer (as indicated on page 2-1 of the application) will affect emission increases at the base plant.

Sierra Club Comment F "BACT Should Include a Flare Gas Recovery System"

- Need to potential proposed BACT limit assuming EPA proceeds EPA proceeds with FGS as BACT (ex. % recovery) and a proposed method for monitoring from this project
- Need any additional supplemental information for BACT or emission changes to the elevated flare and the ground flare assuming FGS as BACT
- Need updated emissions for the elevated flare
- Please indicate if the emission unit(s) intended to utilize recovered product/process gases as fuel is already permitted to utilize the product/recovered process gases as fuel.
- Changes to existing emissions for any downstream emission points receiving recovered gases.
- ExxonMobil's review for PSD applicability of downstream units assuming FGS as BACT for this project

Please call Aimee or myself if you have questions.

Jeff Robinson, Section Chief
Air Permits Section
EPA Region 6
214-665-6435

RE: *Baytown Olefins Plant Draft Permit PSD-TX-102982-GHG*

Sierra Club Comment C(3)(b)(ii) "The Cost Analysis for Carbon Capture and Sequestration is Invalid – Annualized Capital Costs"

- Please provide additional information on how the annualized capital costs for CCS were calculated. In particular, are there any additional specifics you can provide for the use of a 19% capital charge rate.

Response: The capital charge rate of 19% used to estimate the annualized capital cost for CCS represents capital charges consistent with the New Source Review (NSR) Workshop Manual (1990). Specifically, on page b.8 in Appendix B of the NSR Workshop Manual, EPA states that "fixed annual costs include plant overhead, taxes, insurance, and capital recovery charges." So, the capital charge rate is the sum of the taxes and insurance, capital recovery factor, and plant overhead. ExxonMobil used a rate of 4% (of total capital cost) for taxes and insurance, consistent with the NSR manual. No tax credits were applied since there is uncertainty in receiving credits on an ongoing basis.[1] The capital recovery factor is based on the available interest rate for the project and the assumed equipment life. The interest rate (i.e., cost of money) for a major venture such as the Proposed BOP Project[2] is based on ExxonMobil's long term (20+ year) assessment of treasury rates with appropriate consideration of investment risk. For a project such as the Proposed BOP Project, that value is in the range of 10% to 14%, and a rate of 14% was used for the analysis of CCS for the Proposed BOP Project. This interest rate appropriately reflects the uncertainty in returns on major ventures as compared to commercial (e.g., bond) markets, and would actually be expected to be much higher if the project was required to implement an unproven and undemonstrated CCS technology that would increase the capital cost of the project by at least 27% and maybe as high as 41%. The analysis of CCS for the Proposed BOP Project assumed a 20 year equipment life, but a shorter equipment life of 10 to 16 years is more likely based on the acidic nature of the process. Based on an interest rate of 14%, a 20 year equipment life, and tax/insurance rate of 4%, the capital recovery factor is 15% and the capital charge rate is 19%. Please note that the range of appropriate interest rates (10% to 14%) and assumed equipment life (10 to 20 years) result in a capital recovery factor range of 12% to 19% and a capital charge rate from 16% to 23%. ExxonMobil used a capital charge rate of 19% in the analysis as noted above. Plant overhead for the Proposed BOP Project was excluded from the capital charge rate analysis because it was included in the annual operating cost analysis.

In the example in Appendix B of the NSR Workshop Manual, the capital charges (i.e., capital charge rate) are almost 16% of the total capital cost of the project. Additionally, other applications for industrial expansions/projects submitted to the EPA Region 6 used interested rates varying from 7% to 12% and equipment life values between 10 and 30 years, resulting in capital recovery factors ranging from 9% to 17%. Thus, capital charge rates as high as 21% were used, if the applicants had accounted for taxes and insurance as allowed by the NSR Workshop Manual (1990).

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[1] The existing Section 45Q is authorized to provide tax credits for only 75 million tons of CO_2, *see* 26 U.S.C. section 45Q(e), which is an insignificant amount when compared to the total amount of CO_2 that is produced each year and that could be sequestered. Given that credits are limited and capped on annual basis, operators cannot be certain whether their projects qualify, whether there are still credits available in a given year, and how many of those credits they will be able to claim, if any. Therefore, there is no guarantee that ExxonMobil will receive a full credit, if any, on a consistent year-to-year basis.

[2] The "Proposed BOP Project" refers to the proposed project at BOP that is the subject of the draft permit PSD-TX-102982-GHG.

Sierra Club Comment D "The Draft Permit Fails to Account for Increased Upstream and Downstream Production (Debottlenecking)"

- Please provide a list of affected but unmodified units that will have an increase of GHG emissions due to this project.

Response: The affected but unmodified units that will have an increase of GHG emissions attributable to this project are anticipated to be the following steam and electricity generators: Boilers A, B, C, and D, Trains, 1, 2, 3, and 4.

- Provide the GHG emissions of affected but unmodified units

Response: The GHG emissions from affected but unmodified units are based on a representative incremental steam demand on the boilers and trains noted above totaling 165 klb/hr of 1,500 pound steam on an annual basis. The affected, unmodified sources identified above will each incrementally increase firing to produce incremental steam and/or electricity for the Proposed BOP Project. Based on this incremental steam production, the accumulative increase in actual GHG emissions at these units is approximately 110,000 tpy of CO_2e.

- Please provide an analysis to show that affected units are not modified (as defined at 40 CFR 52.21(b)(2)) as a result of this project.

Response: The affected units are not modified (as defined at 40 CFR 52.21(b)(2)) as a result of this project because we are not making physical change or change in the method of operation. There is only increased utilization of the units. Furthermore, the units are not subject to BACT review pursuant to 40 CFR 52.21(j)(3) which states, "*A major modification shall apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur <u>as a result of a physical change or change in the method of operation in the unit</u>.*" *[Emphasis added]* This is also supported by EPA's GHG permitting guidance which notes that "BACT applies in the context of a modification to only an emission unit that has been modified or added to an existing unit." (PSD and Title V Permitting Guidance for Greenhouse Gases, p. 23, March 2011)

- In particular, please address how the bottoms product from the new deethanizer being utilized as a feed to the existing base plant depropanizer (as indicated on page 2-1 of the application) will affect emission increases at the base plant.

Response: The bottoms product from the new deethanizer being utilized as a feed to the existing base plant depropanizer (as indicated on page 2-1 of the application) will not result in an actual GHG emissions increase from the depropanizer column or at any downstream column/separator. This is because emissions from fugitive components are not dependent upon the unit throughput. However, there may be an increase in the heat duty and/or electrical demand of the depropanizer's (and/or downstream columns') reboilers or condenser pumps. These utilities (i.e. steam and electricity) are provided, at least in part (electricity might be purchased), by the existing boilers and trains noted above. Therefore, an actual increase in GHG emissions attributable to increased utilization of the boilers and/or trains may occur. No other actual emission increases in GHG are expected as a result of the new deethanizer being utilized as a feed to the existing base plant depropanizer.

Sierra Club Comment F "BACT Should Include a Flare Gas Recovery System"

- Need to potential proposed BACT limit assuming EPA proceeds EPA proceeds with FGS as BACT (ex. % recovery) and a proposed method for monitoring from this project
- Need any additional supplemental information for BACT or emission changes to the elevated flare and the ground flare assuming FGS as BACT
- Need updated emissions for the elevated flare
- Please indicate if the emission unit(s) intended to utilize recovered product/process gases as fuel is already permitted to utilize the product/recovered process gases as fuel.
- Changes to existing emissions for any downstream emission points receiving recovered gases.
- ExxonMobil's review for PSD applicability of downstream units assuming FGS as BACT for this project

Response: In "*F. BACT Should Include a Flare Gas Recovery System*" on page 16 – 17 of the SC Letter, Sierra Club commented on cost analysis for the Flare Gas Recovery (FGR) System. We agree with EPA's determination in the issuance of the Permit PSD-TX-752-GHG for the expansion at Equistar's La Port facility that it is technically infeasible to implement a FGR system that completely eliminates the need for routine or intermittent flaring at an ethylene production plant when a process involves a wide range of process gas compositions.[3] The proposed project at BOP, which is the subject of the above referenced draft permit (the "Proposed BOP Project"), also includes a wide variation in flow and composition that render elimination of a flare technically infeasible through installation of a FGR system.

Unlike refineries, steam-ethane crackers (i.e., ethylene production plants like BOP) process feed, intermediates, and products that are almost exclusively in the gas phase. Refineries mainly handle liquid feed, intermediates, and product, and therefore, have much less complex flare gas recovery design considerations. Even still, refineries cannot eliminate flaring completely through implementation of FGR systems. This is because at refineries, and even more so at steam-ethane crackers where gas volumes are significantly greater, the only technically practical and safe way to manage large gas flows (such as emergency and MSS) is through a flare.

Further, proper and economic design for even partial FGR system at a proposed grass roots ethylene production unit is technically infeasible since the flows and compositions are theoretical design values from a single production unit. In order to properly design and estimate costs for a FGR system, a detailed flow and composition analysis of the streams recovered by the FGR system must be evaluated to determine the size and configuration of the system and to identify technically feasible flare gas sinks. When actual flows and compositions are not available as a design basis and theoretical values must be relied upon, there is significant uncertainty about the design and operability of the system. As such, design of a FGR system for a stand-alone grassroots ethylene production will likely result in sub-optimal performance, reliability issues, and higher than estimated cost if implemented.

In the ExxonMobil's October 2012 response to EPA on the Proposed BOP Project ("October 2012 Letter"), a FGR System was not eliminated in Step 2 of the BACT analysis because the technology was "available", i.e., all the components existed and have been implemented in other industries (such as refining). Although we do not agree that the "availability" of a technology makes it "technically feasible" as discussed above, a FGR system was carried through the Top-Down BACT Analysis because it was also appropriately demonstrated to be cost prohibitive in Step 4 of the BACT analysis in the October 2012 Letter. Thus, it was not selected as BACT for the proposed project. Because of the performance and

[3] http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/equistar_laporte_%20finalpermit.pdf; http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/equistar_laporte-sob011813.pdf

reliability issues described above, the cost per ton would increase with a more detailed cost evaluation of a functional FGR system for the Proposed BOP Project.

As a separate project, ExxonMobil is planning to implement a FGR system at its existing BOP plant ("Existing Plant"). In response to comments, ExxonMobil is providing additional information regarding a FGR system for the Proposed BOP Project to build upon the information provided in the October 2012 Letter. See *City of Palmdale* PSD Appeal No. 11-07 (September 17, 2012) (finding that EPA's decision not to go to public comment based upon the agency's review and revision of a permit due to a public comment was appropriate.) In particular, ExxonMobil has evaluated sending the flare gas from the Proposed BOP Project to the planned FGR system at the Existing Plant. If the Proposed BOP Project is connected to the planned FGR system at the Existing Plant, it is no longer technically infeasible or cost prohibitive to capture and compress some of the Proposed BOP Project flare gas.[4]

Recovery of flare gas could be considered as BACT for the Proposed BOP Project in this limited circumstance because the separate project makes a collection of the Proposed BOP Project elevated flare technically and economically feasible. The Existing Plant historical data is being used to properly and economically design the planned FGR system for the Existing Plant, and the cumulative effects of multiple flare gas sources (the two existing flare systems) allows for less variation in routine flows and compositions and provides a more reliable feed to flare gas sinks (e.g., boilers or trains). The cost to utilize the available capacity in the planned FGR system at the Existing Plant is dramatically less than the stand-alone FGR system for the Proposed BOP Project.

Connecting the Proposed BOP Project to the FGR system at the Existing Plant will not change the design of the Proposed BOP Project elevated flare or ground flare. The ground flare will still be required for intermittent flaring or unplanned flaring that cannot be captured by the planned FGR system at the Existing Plant. Although the GHG emission limits will be less for the elevated flare for the Proposed BOP Project, the elevated flare will still be required as a safety device and for some routine and intermittent flaring from the Proposed BOP Project.

Furthermore, connecting the Proposed BOP Project to the planned FGR system at the Existing Plant will not change the design of the planned FGR system at the Existing Plant or result in a modification to the Existing Plant flare gas sinks (i.e., boilers or trains) since the units are already authorized to use process gas (i.e., plant tail gas) as fuel. [See 40 CFR §52.21(b)(2)(iii)(e)(2).[5]] In addition, an actual increase in GHG emissions attributable to the combustion of the Proposed BOP Project elevated flare gas in the Existing Plant flare gas sinks (i.e., the boilers or trains) is not expected since an equivalent amount of blended fuel gas (on a MMBtu/hr basis) will be removed from the fuel feed to the units. Therefore, with regard to GHG, there is no modification to the flare gas sinks (i.e., the boilers or trains) or expected increase in actual GHG emissions as a result of connecting the Proposed BOP Project to the planned FGR system at the Existing Plant. The Existing Plant FGR system is anticipated to be authorized under the state minor source standard permit for a pollution control project. There will not be a request to increase the existing plant-wide applicability limits (PALs); therefore, federal (PSD or NNSR) review will not be triggered for the Existing Plant FGR system. In addition, if the Proposed BOP Project's recovered flare

[4] Because the planned FGR system at the Existing Plant is a separate project, only the cost to connect the Proposed BOP Project is considered when evaluating this option, not the total cost to build the planned FGR system at the Existing Plant. The cost analysis does not build upon the FGR system analysis in the October 2012 Letter.

[5] *(iii) A physical change or change in the method of operation shall not include:…*

(e) Use of an alternative fuel or raw material by a stationary source which:…

(2) The source is approved to use under any permit issued under 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.166;

gas is routed to the FGR system at the Existing Plant, it will not change the federal or state permitting requirements.

It is important to note that the planned FGR system at the Existing Plant cannot be utilized to capture and compress all of the flare gas to the Proposed BOP Project's elevated flare. The incremental costs associated with reliably eliminating all flow to the Proposed BOP Project flare is cost prohibitive as discussed below. See *City of Palmdale*, PSD Appeal No. 11-07 (September 17, 2012*)* (finding that the solar technology required in the final permit in response to comments was appropriately sized for the scope of the project and that additional solar panels were infeasible due to space constraints). Connecting the Proposed BOP Project to the planned FGR system at the Existing Plant will allow for collection of approximately 70% of the flare gas to the elevated flare (EPN FLAREXX1) on an annual basis. As a result, the remaining GHG emissions at the elevated flare will represent less than 1% of the total Proposed BOP Project CO_2e emissions.

In order to collect more than 70% of the flare gas to the Proposed BOP Project elevated flare, the planned FGR system at the Existing Plant would require a larger compressor to process the gas, upgrades to the plant electrical infrastructure such as supply, substations, cable, etc. to operate the larger system, and modification to additional flare gas sink(s) at the BOP Plant to accept the additional gas. The following table shows the incremental costs associated with modifying the planned FGR system at the Existing Plant to further reduce CO_2e emissions beyond 70%. To increase the flare gas recovery from 70% to 85% at the Proposed BOP Project elevated flare, it would cost approximately $938/ton of CO_2e avoided. Any further increase in collection of flare gas beyond 85%, especially to eliminate the elevated flare completely, would result in an incremental cost greater than $938/ton of CO_2e avoided and may be not technically feasible.

Table 1. Incremental Cost Analysis for FGR System

Item	Units	Value	Comments
Flare Gas Recovery System Cost Incremental Cost			
Incremental Capital Cost of FGR	$ (millions)	30.0	Additional $16M to increase compressor size, eletrical capacity, and sink availability.
Amortized Incremental Capital Cost	$ (millions)	5.7	Capital Charge Rate of 0.19 (~ 14% interest rate and ~ 4% tax rate) for 20 yr equipment life.
Incremental Operating and Maintenance Expenses	$ (millions)	-0.5	Conservatively assumed only incremental blended fuel gas consumption reduction and that blended fuel as is all purschased natural gas. Positive incremental O&M costs are expected.
Incremental Total Annual FGR Cost	**$ (millions) / yr**	**5.2**	**= (5.7 M$) + (-0.5 M$)**
Icremental Flare Gas Recovered			
Incremental Flare Gas Recovered	MMscf/yr	112.1	Estimated recovered flare gas.
	Btu/scf	881.4	Higher heating value.
	MMBtu/yr	98,835	Higher heating value of 881.1 Btu/scf.
Economics of Incremental Avoided CO_2e			
Avoided Emissions at Flare	tons CO_2e / yr	6,064	Emissions avoided by not flaring flare gas. Does not subtract additional emissions from flare purge.
Generated Emissions Firing Flare Gas as Fuel	tons CO_2e / yr	5,861	Emissions generated when firing recovered flare gas as fuel.
Avoided Emissions Firing Flare Gas as Fuel	tons CO_2e / yr	5,339	Blended fuel gas combustion emissions avoided when firing recovered flare gas as fuel.
Incremental Tons of CO_2e Avoided	**tpy**	**5,542**	**= 6064 tpy + 5339 tpy -5861 tpy**
Incremental Cost per Ton of CO_2e Avoided	**$ / ton CO_2e**	**938**	**= 5.2 M$ / 5542 tpy**

Consistent with other EPA Region 6 permits authorizing a FGR system[6], the following operational limitations and monitoring requirements are proposed to demonstrate BACT:

- Install and operate a flare gas recovery system to collect 70% or more of the flare gas from the elevated flare (EPN FLAREXX1) on a 12-month rolling basis, excluding periods of flaring during malfunction or maintenance, start-up, and shutdown.
- The recovered elevated flare gas shall be used as a fuel source.
- Continuous measurement of the flow of recovered elevated flare gas using an operational non-resettable elapsed flow meter; or a computer that collects, sums, and stores electronic data from the continuous fuel flow meter as a totalizer.

The enforceable performance standard is reflected in the above referenced demonstration of BACT and the reduced flare system emissions cap. Attached are the revised emission calculations for the staged flare system (EPNs FLAREXX1 and FLAREXX2) based on the level of control discussed above. Please note that during periods when all flare gas to the elevated flare is routed to the planned FGR system, there is a required safety purge of the elevated flare (EPN FLAREXX1) using natural gas to avoid air ingress which can be an explosion hazard. The GHG emissions associated with combustion of the natural gas purge are included in the revised emission calculations as well.

[6] For example, http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/oneok-final-permit072313.pdf

Revised Emission Calculations

Table 3-1
Emission Point Summary

Date:	September 2013	Permit No.:	PSD-TX-102982-GHG	Site Name:	Baytown Olefins Plant
Company Name:	ExxonMobil Chemical Company			Project:	Ethylene Expansion

Air Contaminant Data					
Emission Point			Component or Air Contaminant Name	GHG Emission Rate (ton/yr)	CO_2e Emission Rate (ton/yr)[A]
EPN	FIN	Name			
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

EPN = Emission Point Number
FIN = Facility Identification Number

Table 3-1
Emission Point Summary

Date:	September 2013	Permit No.:	PSD-TX-102982-GHG	Site Name:	Baytown Olefins Plant
Company Name:	ExxonMobil Chemical Company			Project:	Ethylene Expansion

Air Contaminant Data					
Emission Point			Component or Air Contaminant Name	GHG Emission Rate (ton/yr)	CO_2e Emission Rate (ton/yr)[A]
EPN	FIN	Name			
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
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

EPN = Emission Point Number
FIN = Facility Identification Number

Table 3-1
Emission Point Summary

Date:	September 2013	Permit No.:	PSD-TX-102982-GHG	Site Name:	Baytown Olefins Plant
Company Name:	ExxonMobil Chemical Company			Project:	Ethylene Expansion

Air Contaminant Data					
Emission Point			Component or Air Contaminant Name	GHG Emission Rate (ton/yr)	CO_2e Emission Rate (ton/yr)[A]
EPN	**FIN**	**Name**			
FLAREXX1 and FLAREXX2	FLAREXX1 and FLAREXX2	Staged Flare System	CO_2	61,944	61,944
			N_2O	5	1,550
			CH_4	49	1,029
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 DIESELXX04 DIESELXX05	DIESELXX01 DIESELXX02 DIESELXX03 DIESELXX04 DIESELXX05	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
Proposed Project Compliance Totals			CO_2	1,442,261	1,442,261
			N_2O	28	8,680
			CH_4	111	2,331
			Total GHG	1,442,400	1,453,272

[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 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	**=**	**10,836 TPY**	
CO_2 Intermittent Flaring Annual Emission Rate	**=**	**48,497 TPY**	
CO_2 Pilot Gas and Natural Gas Purge Annual Emission Rate	**=**	**2,611 TPY**	
CO_2 Annual Emission Rate	**=**	**61,944 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 and Natural Gas Purge 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	**=**	**31 TPY**	
CH_4 Intermittent Flaring Annual Emission Rate	**=**	**4 TPY**	
CH_4 Pilot Gas and Natural Gas Purge Annual Emission Rate	**=**	**14 TPY**	
CH_4 Annual Emission Rate	**=**	**49 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	**=**	**64,523 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
Vent Gas 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	224 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	**=**	**10,836 TPY**	$= E_F * MW_{CO2} / MW_C * Q_V * 10^6 * M_V / V_{MS} * CC_{gas}$ / 2000 lb/ton Equation Y-1a
3. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	6.0E-04 kg/MMBtu	40 CFR 98 Subpart Y
N_2O Annual Emission Rate	**=**	**1 TPY**	$= CO_2$ TPY $* F_{N2O} / F_{CO2}$ Equation Y-5
4. CH_4 Emission Rate Calculations			
CH_4 Emission Factor	F_{CH4}	3.0E-03 kg/MMBtu	40 CFR 98 Subpart Y
Wt. fraction of carbon in fuel gas from CH_4	f_{CH4}	0.37	Calculated from representative stream speciation
CH_4 Annual Emission Rate	**=**	**31 TPY**	$= (CO_2$ TPY $* F_{CH4} / F_{CO2}) + (CO_2$ TPY $* C_F * MW_{CH4}/MW_{CO2} * f_{CH4})$ Equation Y-4
5. CO_2e Emission Rate Calculations			
CO_2 CO_2e Factor	Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor	Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor	Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	**=**	**11,797 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 and Natural Gas Purge 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 Pilot Natural Gas Volume Flow	Q_V	1,589 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	**=**	**805 TPY**	$= 0.98 * MW_{CO2} / MW_C * Q_V * t * M_V / V_{MS} * CC_{gas}$ / 2000 lb/ton Equation Y-1a
3. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	6.0E-04 kg/MMBtu	40 CFR 98 Subpart Y
N_2O Annual Emission Rate	**=**	**1 TPY**	$= CO_2$ TPY $* F_{N2O} / F_{CO2}$ Equation Y-5
4. CH_4 Emission Rate Calculations			
CH_4 Emission Factor	F_{CH4}	3.0E-03 kg/MMBtu	40 CFR 98 Subpart Y
Wt. fraction of carbon in fuel gas from CH_4	f_{CH4}	0.95	Calculated from representative stream speciation
CH_4 Annual Emission Rate	**=**	**6 TPY**	$= (CO_2$ TPY $* F_{CH4} / F_{CO2}) + (CO_2$ TPY $* C_F * MW_{CH4}/MW_{CO2} * f_{CH4})$ Equation Y-4
5. CO_2e Emission Rate Calculations			
CO_2 CO_2e Factor	Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor	Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor	Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	**=**	**1,241 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
Vent Gas 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 Equation Y-1a
3. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	6.0E-04 kg/MMBtu	40 CFR 98 Subpart Y
N_2O Annual Emission Rate	**=**	**1 TPY**	$= CO_2$ TPY $* F_{N2O} / F_{CO2}$ Equation Y-5
4. CH_4 Emission Rate Calculations			
CH_4 Emission Factor	F_{CH4}	3.0E-03 kg/MMBtu	40 CFR 98 Subpart Y
Wt. fraction of carbon in fuel gas from CH_4	f_{CH4}	0.04	Calculated from representative stream speciation
CH_4 Annual Emission Rate	**=**	**4 TPY**	$= (CO_2$ TPY $* F_{CH4} / F_{CO2}) + (CO_2$ TPY $* C_F * MW_{CH4}/MW_{CO2} * f_{CH4})$ 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 (Ethane) 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 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 Equation Y-1a
3. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	6.0E-04 kg/MMBtu	40 CFR 98 Subpart Y
N_2O Annual Emission Rate	=	**1 TPY**	= CO_2 TPY * F_{N2O} / F_{CO2} Equation Y-5
4. CH_4 Emission Rate Calculations			
CH_4 Emission Factor	F_{CH4}	3.0E-03 kg/MMBtu	40 CFR 98 Subpart Y
Wt. fraction of carbon in fuel gas from CH_4	f_{CH4}	0.01	Calculated from representative stream speciation
CH_4 Annual Emission Rate	=	**1 TPY**	= (CO_2 TPY * F_{CH4} / F_{CO2}) + (CO_2 TPY * C_F * MW_{CH4}/MW_{CO2} * f_{CH4}) Equation Y-4
5. 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**	= Σ (TPY * Fe_x)

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

ExxonMobil Chemical Company
Baytown Olefins Plant
Pilot Gas (Natural Gas) to FLAREXX2
Greenhouse Gas Emissions Calculations

Parameter Name & Variable		Value & Units	Basis/Calculation/Notes
1. General Values and Calculations			
Standard Molar Volume	V_{MS}	385 scf/lb-mol	Based on ideal gas law
Total Flare Natural Gas Volume Flow	Q_V	1,800 scf/hr	Design rate
Avg. Molecular Weight of Natural Gas	M_V	17.0 lb/lb-mol	Calculated from stream speciation
Avg. Carbon Content of Natural Gas	CC_{gas}	0.73 lb_C/lb_{gas}	Calculated from stream speciation
CO_2 Emission Factor	F_{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 Equation Y-1a
3. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	6.0E-04 kg/MMBtu	40 CFR 98 Subpart Y
N_2O Annual Emission Rate	=	**1 TPY**	$= CO_2$ TPY $* F_{N2O} / F_{CO2}$ Equation Y-5
4. CH_4 Emission Rate Calculations			
CH_4 Emission Factor	F_{CH4}	3.0E-03 kg/MMBtu	40 CFR 98 Subpart Y
Wt. fraction of carbon in fuel gas from CH_4	f_{CH4}	0.95	Calculated from representative stream speciation
CH_4 Annual Emission Rate	=	**7 TPY**	$= (CO_2$ TPY $* F_{CH4} / F_{CO2}) + (CO_2$ TPY $* C_F * MW_{CH4}/MW_{CO2} * f_{CH4})$ 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.