Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Chevron Phillips Chemical Company, Cedar Bayou Plant

Permit Number: PSD-TX-748-GHG

October 2012

This document serves as the statement of basis for the above-referenced draft permit, as required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On December 19, 2011, the Chevron Phillips Chemical Company (Chevron Phillips) Cedar Bayou Plant submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions from a proposed modification. On March 19, 2012, Chevron Phillips submitted a revised application. In connection with the same proposed project, Chevron Phillips submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on December 14, 2011. The project at the Cedar Bayou Plant proposes to construct a new ethylene production unit (Unit 1594) consisting of eight ethylene cracking furnaces and supporting equipment to produce polymer grade ethylene. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the Chevron Phillips, Cedar Bayou Plant.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that Chevron Phillip's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by Chevron Phillips, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

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III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305). Texas still retains approval of its plan and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Aimee Wilson
Air Permitting Section (6PD-R)
(214) 665-7596

The Non-GHG PSD Permitting Authority for the State of Texas is:

Air Permits Division (MC-163)
TCEQ
P.O. Box 13087
Austin, TX 78711-3087

IV. Facility Location

The Chevron Phillips, Cedar Bayou Plant is located in Harris County, Texas. The geographic coordinates for this facility are as follows:

Latitude: 29º 49' 20" North
Longitude: - 94º 55'18" West

Harris County is currently designated severe nonattainment for ozone, and is currently designated attainment for all other pollutants. The nearest Class I area is at a distance of more than 500 kilometers is Breton National Wildlife Refuge.

Below, Figure 1 illustrates the facility location for this draft permit.

Figure 1. Chevron Phillips Chemical Company, Cedar Bayou Plant Location

V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA concludes Chevron Phillip's application is subject to PSD review for the pollutant GHGs, because the project would lead to a net emissions increase of GHGs for a facility as described at 40 CFR § 52.21(b)(23) and (49)(iv). Under the project, GHG emissions are calculated to increase over zero tpy on a mass basis and to exceed the applicability threshold of 75,000 tpy CO_2e (Chevron Phillips calculates CO_2e emissions of 1,615,000 tpy). EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305

The applicant represents that TCEQ, as the permitting authority for regulated NSR pollutants other than GHGs, is expected to subject the project to PSD review for NO_2, CO, and $PM_{10}/PM_{2.5}$ and NNSR review for NOx and VOC. At this time, TCEQ has not issued the PSD permit amendment for non-GHG pollutants or the Nonattainment NSR permit for nonattainment pollutants.

Accordingly, under the circumstances of this project, the State will issue the non-GHG portion of the PSD permit, and EPA will issue the GHG portion.[1]

EPA Region 6 applies the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, and we have not required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the project has triggered review for regulated NSR pollutants that are non-GHG pollutants under the PSD permit sought from TCEQ.

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow Chevron Phillips to construct a new ethylene production unit (Unit 1594) consisting of eight furnaces and supporting equipment at the existing ethylene production facility at the Cedar Bayou Plant located in Baytown, Harris County, Texas. The modification increases the plant capacity adding approximately 1.5 million metric tons per year of polymer grade ethylene produced. The site will also have an increase in other products, including fuel gas, propylene, a heavy components (C3+) stream, and other lower-output hydrocarbon streams.

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[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

The cracking furnaces consist of eight (8) proprietary Ultra Selective Conversion induced draft furnaces (EPNs H-10100 to H-10800). The unit typically operates with seven furnaces with one furnace available for decoking and hot steam standby. The furnaces are equipped with low NOx burners and selective catalytic reduction (SCR) systems to control NOx emissions. Continuous Emission Monitoring Systems (CEMS) for NOx, CO, and oxygen, will be installed on each furnace. The pyrolysis of hydrocarbons forms coke in the heater tubes that must be periodically removed by using steam/air decoking. The furnaces typically operate for approximately fifty days before being taken off-line for decoking. The decoking procedure oxidizes and spalls the coke. Furnace fuel is plant fuel gas supplemented by natural gas.

The VHP boiler (EPN B-83010) is designed to supply very high pressure steam to the cracker during start-up and supplement steam produced in the furnaces. Also, low pressure vent streams collected throughout the cracker plant are routed to the boiler firebox for control. The boiler is equipped with ultra-low NOx burners, an
SCR system, and NOx, CO, and oxygen CEMS, with ammonia slip calculated by mass balance.

Low pressure vent streams from various points in the process are collected and routed to the firebox of the VHP boiler for destruction. For periods when the boiler is down, the low pressure vent streams are routed to a backup vapor destruction unit (VDU) (EPN PK-90060) while maintenance or inspections are conducted on the boiler.

The low profile flare is designed for the safe control of gases vented from the ethylene cracker and support units. The low profile flare consists of multiple stage rows with several high capacity burners on each row. There is one staged burner for low pressure vents such as sweep gas, fugitive-like sources such as “leak by” from safety relief and pressure control valves, small volume maintenance activities such as clearing small volume equipment such as pumps, analyzers, instruments, and associated piping. The high capacity burners handle high pressure discharges due to emergencies, start-up and shutdown operations, and other large volume maintenance clearing. The system is equipped with a totalizing flow meter and an on-line analyzer to speciate the hydrocarbons in the flare gases, including Highly Reactive Volatile Organic Compounds (HRVOCs).

The ethylene unit includes up to six emergency generators, with an approximate aggregate power output of 4 MW total. The units are each powered by a diesel engine, and there is one diesel tank associated with each emergency generator. Each generator engine’s normal operation is to run one hour per week to test for proper operation, in the event it needs to be used in an emergency situation.

VII. General Format of the BACT Analysis

The BACT analyses were conducted in accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outlined in the 1990 draft U.S. EPA *New Source Review Workshop Manual*, which outlines the steps for conducting a top-down BACT analysis. Those steps are listed below.

(1) Identify all potentially available control options;

(2) Eliminate technically infeasible control options;

(3) Rank remaining control technologies;

(4) Evaluate the most effective controls and document the results; and

(5) Select BACT.

Also in accordance with the top-down BACT guidance, the BACT analyses also take into account the energy, environmental, and economic impacts of the control options during step 4. Emission reductions may be determined through the application of available control techniques, process design, and/or operational limitations. Each of the emission unit submitted in the PSD GHG application was evaluated separately in the top-down 5-step BACT analysis.

VIII. Applicable Emission Units and BACT Discussion

The majority of the contribution of GHGs associated with the project is from combustion sources (i.e., cracking furnaces, VHP boiler, vapor destruction unit, flare, and emergency generator testing). The site has some fugitive emissions from piping components which contribute an insignificant amount of GHGs. These stationary combustion sources primarily emit carbon dioxide (CO_2), and small amounts of nitrous oxide (N_2O) and methane (CH_4). The following devices are subject to this GHG PSD permit:

- Steam Cracking Furnaces
- VHP Boiler
- Vapor Destruction Unit
- Low Profile Flare
- Emergency Generators
- Piping Fugitives

IX. Steam Cracking Furnaces (H-10100, H-10200, H-10300, H-10400, H-10500, H-10600, H-10700, and H-10800)

The ethylene unit consists of eight proprietary Ultra Selective Conversion induced draft furnaces (H-10100 to H-10800). The ethylene unit typically operates with seven furnaces with one furnace available for decoking and hot steam standby. The furnaces are equipped with low NOx burners and selective catalytic reduction (SCR) systems to control NOx emissions. Furnace fuel is plant fuel gas supplemented by natural gas. Ethane may be used as an emergency backup fuel.

As part of the PSD review, Chevron Phillips provides in the GHG permit application a 5-step top-down BACT analysis for the eight steam cracking furnaces. EPA has reviewed Chevron Phillip's BACT analysis for the furnaces, which has been incorporated into this Statement of Basis, and also provides its own analysis in setting forth BACT for this proposed permit, as summarized below.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Carbon Capture and Storage* – CCS is an available add-on control technology that is applicable for all of the sites affected combustion units.
- *Energy Efficient Design* – Chevron Phillips selected an energy efficient proprietary design for its integrated cracking furnaces and boiler, to optimize steam, fuel, and overall energy balances across the site, not just for a single furnace or boiler. Chevron Phillips proposes to use a proprietary furnace and integrated cold system design. The proprietary design recovers refrigeration capacity from incoming ethane feed to reduce demand for refrigeration compression power downstream of the furnaces, resulting in reduced high pressure steam demand and thus reducing the required fuel combustion for steam generation. Lower pressure separation of ethylene and ethane likewise reduces compression and resulting steam demand and CO_2 generation from combustion. The system also incorporates an optimized distillation tower design, resulting in minimization of reboiler and reflux demand. Further, excess high-pressure steam is anticipated from incorporation of these energy efficient measures reducing the need for steam generation in the boiler.
- *Low Carbon Fuels* – Use of fuels containing lower concentrations of carbon generate less CO_2 than other higher-carbon fuels. Typically, gaseous fuels such as natural gas or high-hydrogen plant tail gas contain less carbon, and thus lower CO_2 potential, than liquid or solid fuels such as diesel or coal. Chevron Phillips proposes to use high-hydrogen plant tail gas as the primary fuel for the cracking furnaces. When this tail gas is unavailable, the alternate fuel will be natural gas.
- *Good Combustion Practices and Maintenance* - Good combustion practices include appropriate maintenance of equipment and operating within the recommended combustion

air and fuel ranges of the equipment as specified by its design, with the assistance of oxygen trim control.

Carbon Capture and Sequestration (CCS)

Carbon capture and sequestration is a GHG control process that can be used by "facilities emitting CO_2 in large concentrations, 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)."[2] For purposes of a BACT analysis, CCS is classified as an add-on pollution control technology. CCS involves the separation and capture of CO_2 from the combustion process flue gas, the pressurization of the captured CO_2 and transported by pipeline or other means of transportation, if necessary, to a site where it is injected into a long-term geological location. Several technologies are in various stages of development and are being considered for CO_2 separation and capture.

As it stands currently, CCS Technology and its components can be summarized in the table below adopted from IPCC's *Carbon Dioxide Capture and Storage* report[3]:

CCS Component	CCS Technology
Capture	Post-combustion
	Pre-combustion
	Oxyfuel combustion
	Industrial separation (natural gas processing, ammonia production)
Transportation	Pipeline
	Shipping
Geological Storage	Enhanced Oil Recovery (EOR)
	Gas or oil fields
	Saline formations
	Enhanced Coal Bed Methane Recovery (ECBM)
Ocean Storage	Direct injection (dissolution type)
	Direct injection (lake type)
Mineral carbonation	Natural silicate minerals
	Waste minerals
CO_2 Utilization/Application	Industrial Uses of CO_2 (e.g. carbonated products)

[2]U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> (March 2011)

[3] Intergovernmental Panel on Climate Change (IPCC) Special Report, Bert Metz, Ogunlade Davidson, Heleen de Coninck, Manuela Loos and Leo Meyer (Eds.), *Carbon Dioxide Capture and Storage* (New York: Cambridge University Press, 2005), Table SPM.2, 8. <http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf>

For large, point sources, there are three types of capture configurations – pre-combustion capture, post-combustion capture, and oxy-combustion capture:

1) Pre-combustion capture implies as named, the capture of CO_2 prior to combustion. It is a technological option available to integrated coal gasification combined cycle (IGCC) plants. In these plants, coal is gasified to form synthesis gas (syngas with key components of carbon monoxide and hydrogen). Carbon monoxide (CO) is reacted with steam to form CO_2 which is then removed and the hydrogen is then diluted with nitrogen and fed into the gas turbine combined cycle.

2) Post-combustion capture involves extracting CO_2 in a purified form from the flue gas following combustion of the fuel. Primarily for coal-fired power plants and electric generating units (EGU), other industries can benefit. Currently, all commercial post-combustion capture is via chemical absorption process using monoethanolamine (MEA)-based solvents.[4]

3) Oxy-combustion technology is primarily applied to coal-burning power plants where the capture of CO_2 is obtained from a pulverized coal oxy-fuel combustion in which fossil fuels are burned in a mixture of recirculated flue gas and oxygen, rather than in air. The remainder of the flue gas, that is not recirculated, is rich in carbon dioxide and water vapor, which is treated by condensation of the water vapor to capture the CO_2.[5] In nearly all existing coal-burning power plants, nitrogen is a major component of flue gas in the boiler units that burn coal in air, post-combustion capture of CO_2 is essentially a nitrogen-carbon dioxide separation which can be done but at a high cost. However if there were no nitrogen present as in the case of oxy-combustion, then CO_2 capture from flue gas would be greatly simplified[6]. It is implied that an optimized oxy-combustion power plant will have ultra-low CO_2 emissions as a result.

Once CO_2 is captured from the flue gas, CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline) into a storage area, in most cases, a geological storage area. It is also possible that CO_2 can be stored and shipped via all different modes of transportation via land, air and sea.

Geological storage of CO_2 involves the injection of compressed CO_2 into deep geologic formations (injection zones) overlain by competent sealing formations and geologic traps that will prevent the CO_2 from escaping. There are five types of geologic formations that are

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[4] Wes Hermann et al. *An Assessment of Carbon Capture Technology and Research Opportunities - GCEP Energy Assessment Analysis, Spring 2005*. <http://gcep.stanford.edu/pdfs/assessments/carbon_capture_assessment.pdf>
[5] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, "Oxy-Fuel Combustion", August 2008. < http://www.netl.doe.gov/publications/factsheets/rd/R&D127.pdf>
[6] Herzog et al., page 4-5

considered: clastic formations; carbonate formations; deep, unmineable coal seams; organic-rich shales; and basalt interflow zones. There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[7]

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Based on the information reviewed for this BACT analysis, while there are some portions of CCS that are technically infeasible, EPA has determined that overall Carbon Capture and Storage (CCS) technology is technologically feasible at this source. Listed below is a summary of those CCS components that are technically feasible and those CCS components that are not technically feasible for Chevron Phillips.

Step Two Summary for CCS for Chevron Phillips

CCS Component	CCS Technology	Technical Feasibility
Capture	Post-combustion	Y
	Pre-combustion	N
	Oxyfuel combustion	N
	Industrial separation (natural gas processing, ammonia production)	N
Transportation	Pipeline	Y
	Shipping	Y
Geological Storage	Enhanced Oil Recovery (EOR)	Y
	Gas or oil fields	N*
	Saline formations	N*
	Enhanced Coal Bed Methane Recovery (ECBM)	N*
Ocean Storage	Direct injection (dissolution type)	N*
	Direct injection (lake type)	N*
Mineral carbonation	Natural silicate minerals	N*
	Waste minerals	N*
Large scale CO_2 Utilization/Application		N*

* Both geologic storage and large scale CO_2 utilization technologies are in the research and development phase and currently commercially unavailable.[8]

[7] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory *Carbon Sequestration Program: Technology Program Plan*, <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf>, February 2011

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- CO_2 capture and storage (up to 90%)
- Low-Carbon Fuel (approximately 40%)
- Energy Efficient Design
- Good Combustion Practices

CO_2 capture and storage is capable of achieving 90% reduction of produced CO_2 emissions and thus considered to be the most effective control method. Use of low-carbon fuel, energy efficient design, and good combustion practices are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. The estimated efficiencies were obtained from Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Managers (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008). This report addressed improvements to existing energy systems as well as new equipment.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

<u>Carbon Capture and Sequestration</u>

EPA considers CCS to be an available control option for high-purity CO_2 streams that merits initial consideration as part of the BACT review process, especially for new facilities. As noted in EPA's GHG Permitting Guidance, a control technology is "available" if it has a potential for practical application to the emissions unit and the regulated pollutant under evaluation. Thus, even technologies that are in the initial stages of full development and deployment for an industry, such as CCS, can be considered "available" as that term is used for the specific purposes of a BACT analysis under the PSD program. In 2010, the Interagency Task Force on Carbon Capture and Storage was established to develop a comprehensive and coordinated federal strategy to speed the commercial development and deployment of this clean coal technology. As part of its work, the Task Force prepared a report that summarized the state of CCS and identified technical and non-technical challenges to implementation.[9] EPA, which participated in the Interagency Task Force, supported the Task Force's conclusion that although current technologies could be used to capture CO_2 from new and existing plants, they were not ready for widespread implementation at all facility types. This conclusion was based primarily on the fact that the technologies had not been demonstrated at the scale necessary to establish confidence in

[8] U.S. Department of Energy, *Carbon Sequestration Program: Technology Program Plan*, page 20-23
[9] See *Report of the Interagency Task Force on Carbon Capture and Storage* available at http://www.epa.gov/climatechange/policy/ccs_task_force.html

their operations. EPA Region 6 has completed a research and literature review and has found that nothing has changed dramatically in the industry since the August 2010 report, and there is no specific evidence of the feasibility and cost-effectiveness of a full scale carbon capture system for the project and equipment proposed by Chevron Phillips.

Chevron Phillips developed a cost analysis for CCS that provided the basis for eliminating the technology in step 4 of the BACT process as a viable control option based on economic costs and environmental impact. The majority of the cost for CCS was attributed to the capture and compression facilities that would be required. The total annual cost of CCS would be $160,000,000 per year. The addition of CCS would increase the total capital project costs by more than 25%. That cost exceeds the threshold that would make the project economically viable. EPA Region 6 reviewed Chevron Phillip's CCS cost estimate and believes it adequately approximates the cost of a CCS control for this project and demonstrates those costs are prohibitive in relation to the overall cost of the proposed project. Thus, CCS has been eliminated as BACT for this project.

Economic infeasibility notwithstanding, Chevron Phillips also asserts that CCS can be eliminated as BACT based on the environmental impacts from a collateral increase of National Ambient Air Quality Standards (NAAQS) pollutants. Implementation of CCS would increase emissions of NOx, CO, VOC, PM_{10}, SO_2, and ammonia by as much as 30%. The proposed plant is located in the Houston, Galveston, and Brazoria (HGB) area of ozone non-attainment and the generation of additional NOx and VOC could exacerbate ozone formation in the area. Since the project is located in an ozone non-attainment area, energy efficient technologies are preferred over add-on controls such as CCS that would cause an increase in emissions of NOx and VOCs to the HGB non-attainment area airshed.

Low-Carbon Fuel

The use of low-carbon fuel is economically and environmentally practicable for the proposed project. By using plant tail gas in the furnaces, the project requires less purchased natural gas, resulting in cost savings. Further, combustion of high-hydrogen fuel in lieu of higher carbon-based fuels such as diesel, coal, or even natural gas reduces emissions of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing environmental benefits as well.

Energy Efficient Design

The use of an energy efficient furnace and unit design is economically and environmentally practicable for the proposed project. By optimizing energy efficiency, the project requires less fuel than comparable less-efficient operations, resulting in cost savings. Further, reduction in fuel consumption corresponding to energy efficient design reduces emissions of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing environmental benefits as well.

Good Combustion Practices

Good combustion practices effectively support the energy efficient design. Thus, the economic and environmental practicability related to energy efficient design also applies to the use of good combustion practices.

Step 5 – Selection of BACT

To date, other similar facilities with a GHG BACT limit are summarized in the table below:

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
BASF FINA Petrochemicals LP, NAFTA Region Olefins Complex Port Arthur, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for furnace limit flue gas exhaust temperature ≤ 309 °F. 365-day average, rolling daily	2012	PSD-TX-903-GHG
Williams Olefins LLC, Geismar Ethylene Plant Geismar, LA	Ethylene Production	Energy Efficiency/Low -emitting Feedstocks/Lower-Carbon Fuels	Cracking heaters to meet a thermal efficiency of 92.5% Ethane/Propane to be used as feedstock Fuel gas containing 25% volume hydrogen on an annual basis	2012	PSD-LA-759

BASF and Williams have differing processes for producing ethylene. BASF is a steam driven operation using multiple feedstocks, whereas Williams is utilizing electrical driven compressors and only ethane/propane as a feedstock which will require less energy consumption. This makes the Williams process more efficient than BASF. The Chevron Phillips facility will be constructed similar to the BASF facility in that it too will be steam driven and will utilize ethane as the primary feedstock. The Chevron Phillips facility also utilizes a configuration that combines the steam production of eight cracking furnaces with a very high pressure boiler. Chevron Phillips exhaust temperature will be higher than BASF due to the design differences of the two facilities.

The following specific BACT practices are proposed for each furnace:

- *Energy Efficient Operation* - Continuously monitor the cracking furnaces' exhaust stack temperature and control to a maximum stack exit temperature of 350 ^{o}F on a 12-month total, rolling average basis, not including periods of startup, shutdown, and decoking.
- *Low Carbon Fuels* – Use of high hydrogen plant tail gas preferentially over pipeline quality natural gas. Natural gas will be used when high hydrogen tail gas is not available.
- *Good Combustion Practices and Maintenance* – The use of good combustion practices includes periodic combustion tune-ups and maintaining the recommended combustion air and fuel ranges of the equipment as specified by its design, with the assistance of oxygen trim control.

BACT Limits and Compliance:

BACT for the furnaces will be to maintain energy efficient operation. Chevron Phillips will demonstrate compliance with energy efficient operations by continuously monitoring the exhaust stack temperature of each furnace. The maximum stack exit temperature of 350 ^{o}F on a 12-month, rolling average basis will be calculated monthly for each furnace.

Chevron Phillips elects to reduce the overall emissions from the furnaces by utilizing a compliance cap for the furnaces and boiler of 1,579,000 tpy CO_2e. Since steam generation from the furnaces is integrated with steam generation from the VHP boiler, the annual emissions from the boiler are included in the compliance cap. This cap is based on the firing of seven furnaces 8,760 hours per year at the annual average firing rate of 412MMBtu/hr, with one furnace being on standby and available for decoking. Although each individual furnace may operate at each unit's proposed annual emissions, the aggregate of the eight furnaces' normal and decoking operations, plus the boiler will not exceed the compliance cap. Chevron Phillips will demonstrate compliance with the CO_2 cap for the furnaces and boiler using the site specific fuel analysis for process fuel gas (see Table A-9 in the GHG permit application) and the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).

CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at §98.33(a)(2)(ii).
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at §98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The proposed permit also includes an alternative compliance demonstration method, in which Chevron Phillips may install, calibrate, and operate a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2, site specific analysis of process fuel gas, and the actual heat input (HHV). To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month average, rolling monthly.

An initial stack test demonstration will be required for CO_2 emissions from at least four of the eight emission units. An initial stack test demonstration for CH_4 and N_2O emissions are not required because the CH_4 and N_2O emission are less than 0.01% of the total CO_2e emissions from the furnaces and are considered a *de minimis* level in comparison to the CO_2 emissions.

X. Decoking Activities

Ethane cracking furnaces require periodic decoking to remove coke deposits from the furnace tubes. Coke buildup is unavoidable in cracking furnaces, and removal of coke at optimal periods maintains the furnace at efficient ethane-to-ethylene conversion rates without increasing energy (fuel) demand. Decoking too early is unnecessary and results in excess shutdown/start-up cycles. Decoking too late results in fouled furnace tubes that reduce conversion rates and increases heat demand. The GHG emissions consist of CO_2 that is produced from combustion of the coke build up on the coils.

Step 1 – Identification of Potential Control Technologies

Proper design and operation of the furnaces in accordance with manufacturer's recommendations is important in managing the formation of coke in furnace tubes. There are no additional available add-on technologies that have been applied to furnace decoking activities to control CO_2 emissions once generated.

Step 2 – Elimination of Technically Infeasible Alternatives

Proper furnace design and operation to minimize coke formation is considered technically feasible for the cracking furnaces.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Only one option, proper design and operation of the furnace, has been identified for controlling GHG emissions from decoking operations; therefore, ranking by effectiveness is not applicable.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

The single option for control of CO_2 from decoking operations is to follow the design and operational parameters integrated into the furnace to limit the need for decoking and thus the corresponding CO_2 emissions generated from the same. As such, it is inherent in the design and operation of cracking furnaces to minimize coke formation as an economic necessity.

Step 5 – Selection of BACT

Chevron Phillips proposes to incorporate a combination of design and recommended operation to limit coke formation in the tubes to the extent practicable considering ethane as a raw material. The steam cracking furnaces will be decoked every 40 to 60 days. Estimated CO_2 emissions from decoke operations is negligible compared to annual total from the furnaces. Managing coke buildup through such methods will result in limited CO_2 formation from periodic decoking operations.

The permit includes conditions to limit decoke events and decoke emissions. The permit limits the eight furnaces to 96 total decokes per year. In addition decoke emissions are included in the overall CO_2e emissions cap for the furnaces and boiler.

XI. VHP Boiler (B-83010)

The VHP boiler is integrated in the energy balance of the entire new cracker plant and cannot be considered a stand-alone device from the standpoint of GHG control methods. The boiler serves not only to generate very high pressure steam (greater than 1,200 psi), but also as the primary control device for low-pressure process vents, obviating the need for a secondary combustion device.

Step 1 – Identification of Potential Control Technologies

- *Carbon Capture and Storage (CCS)* – CCS is an available add-on control technology that is applicable for all of the sites affected combustion units.
- *Energy Efficient Design* – The energy efficient measures integrated into the cracking plant as described for the furnaces also applies generally to the boiler, since it likewise is a contributor to the overall steam balance of the plant and must be considered as integrated in the overall plant energy efficient design.
- *Low Carbon Fuels* – The boiler will use pipeline quality natural gas as the primary fuel, with high-hydrogen plant tail gas available as a second low-carbon fuel, when available.
- *Good Combustion Practices and Maintenance* - Good combustion practices include appropriate maintenance of equipment and operating within the recommended combustion air and fuel ranges of the equipment as specified by its design, with the assistance of oxygen trim control.

<u>Carbon Capture and Storage</u>

This add-on control technology was already discussed in detail in section IX. Based on the economic infeasibility and environmental issues discussed in section IX above, CCS will not be considered further in this analysis.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible. CCS will not be considered further based on the evaluation in section IX above.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Energy Efficient Design
- Low-Carbon Fuel
- Good Combustion Practices

Energy efficient design, use of low-carbon fuel, and good combustion practices are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Energy Efficient Design

The use of an energy efficient boiler design is economically and environmentally practicable for the proposed project. The integrated design of the cracking furnaces and the VHP boiler reduces the steam demand of the VHP boiler reducing the fuel combustion of the VHP boiler, thus reducing CO_2 generation. By optimizing energy efficiency, the project requires less fuel than comparable less-efficient operations, resulting in cost savings. Further, reduction in fuel consumption corresponding to energy efficient design reduces emissions of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing environmental benefits as well.

Low-Carbon Fuel

The use of low-carbon fuel is economically and environmentally practicable for the proposed project. Combustion of gaseous fuel in lieu of higher carbon-based fuels such as diesel or coal reduces emissions of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing environmental benefits as well.

Good Combustion Practices

Good combustion practices effectively support the energy efficient design. Thus, the economic and environmental practicability related to energy efficient design also applies to the use of good combustion practices.

Step 5 – Selection of BACT

To date, other similar facilities with a GHG BACT limit are summarized in the table below:

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
BASF FINA Petrochemicals LP, NAFTA Region Olefins Complex Port Arthur, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for steam package boilers - monitor and maintain a thermal efficiency of 77% 12-month rolling average basis	2012	PSD-TX-903-GHG

The following specific BACT practices are proposed for the VHP boiler:

- *Energy Efficient Operation* – The boiler will operate at less than design maximum rates under normal operation to control process vents, but may operate at higher rates when additional steam demand is necessary for the cracker unit and/or other process areas onsite. Due to the expected fluctuation in operational rates due to multiple purposes of the boiler, and the fact that process vents may provide variable heating value, the energy efficiency of the boiler will be monitored by the excess air to the boiler. Chevron Phillips will demonstrate operational BACT for the VHP Boiler by calculating the thermal efficiency of the unit monthly and maintaining a 77% thermal efficiency on a 12-month rolling average basis.
- *Low Carbon Fuels* – The boiler will operate primarily on pipeline natural gas unless supplemental tail gas is available.
- *Good Combustion Practices and Maintenance* – The use of good combustion practices includes periodic tune-ups and maintaining the recommended combustion air and fuel ranges of the equipment as specified by its design, with the assistance of oxygen trim control.

BACT Limits and Compliance:

BACT for the VHP boiler will be to maintain no less than a 77% thermal efficiency on a 12-month rolling average. Chevron Phillips elects to demonstrate compliance with a 77% thermal efficiency on the VHP Boiler using the following equation:

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

Chevron Phillips elects to reduce the overall emissions from the furnaces by utilizing a compliance cap for the furnaces and boiler of 1,579,000 tpy CO_2e. Since steam generation from the furnaces is integrated with steam generation from the VHP boiler, the annual emissions from the boiler are included in the compliance cap. The boiler emissions contributed to the compliance cap are based on operation of 720 hrs/yr at the maximum firing rate (500 MMBtu/hr), 48 hrs/yr in startup (500 MMBtu/hr), and the balance (7,992 hrs) at the normal firing rate of 150 MMBtu/hr. Although these assumptions represent the basis for calculating the annual emission cap, Chevron Phillips is not proposing specific limitations on boiler operating rates or schedules as long as compliance with the cap is demonstrated. Chevron Phillips will demonstrate compliance with the CO_2 cap for the furnaces and boiler using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1, and the site specific fuel analysis for process fuel gas. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at §98.33(a)(2)(ii).
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at §98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The proposed permit also includes an alternative compliance demonstration method, in which Chevron Phillips may install, calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2, site specific analysis of process fuel gas, and the actual heat input (HHV). To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month average, rolling monthly.

An initial stack test demonstration will be required for CO_2 emissions from the emission unit. An initial stack test demonstration for CH_4 and N_2O emissions are not required because the CH_4 and N_2O emission are less than 0.01% of the total CO_2e emissions from the boiler and are considered a *de minimis* level in comparison to the CO_2 emissions.

XII. Vapor Destruction Unit (PK-90060)

The Vapor Destruction Unit (VDU) serves as a standby vent control system, which is not anticipated to operate (except in hot standby/pilot-only mode) more than the equivalent of four to eight weeks each year, when the primary control device, the VHP boiler, may not be operational due to maintenance or inspection. The VDU is fueled by pipeline quality natural gas. The CO_2e emissions from the VDU account for less than 1% of the total CO_2e emissions for this project.

Step 1 – Identification of Potential Control Technologies

- *Carbon Capture and Storage (CCS) –* CCS is an available add-on control technology that is applicable for all of the sites affected combustion units.
- *Low Carbon Fuels –* The VHP will use pipeline quality natural gas during hot standby mode and as supplemental fuel when the VDU controls low pressure vent streams.
- *Good Combustion Practices and Maintenance -* Good combustion practices include appropriate maintenance of equipment and operating within the recommended combustion air and fuel ranges of the equipment as specified by its design, with the assistance of oxygen trim control.

<u>Carbon Capture and Storage</u>

This add-on control technology was already discussed in detail in section IX. Based on the economic infeasibility and environmental detriment issues discussed in section IX above, CCS will not be considered further in this analysis.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible. CCS will not be considered further based on the evaluation in section IX above.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Low-Carbon Fuel
- Good Combustion Practices

Use of low-carbon fuel and good combustion practices are both considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

<u>Low-Carbon Fuel</u>

The use of low-carbon fuel is economically and environmentally practicable for the proposed project. Combustion of gaseous fuel in lieu of higher carbon-based fuels such as diesel or coal reduces emissions of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing environmental benefits as well.

<u>Good Combustion Practices</u>

Good combustion practices effectively support the proper operation of the VDU as a standby control device.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the VDU:

- *Low Carbon Fuels* – The VDU will combust pipeline quality natural gas in the pilots when in hot standby mode, and when controlling gaseous vent streams, natural gas will be used as supplemental fuel, if needed, to maintain combustion temperatures.
- *Good Combustion Practices and Maintenance* – The use of good combustion practices includes periodic tune-ups and maintaining the recommended combustion air and fuel ranges of the equipment as specified by its design, with the assistance of oxygen trim control.

Using the BACT practices above will result in a BACT limit for the VDU of 2,400 tpy CO_2e. Chevron Phillips will demonstrate compliance with the CO_2 emission limit using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1, and the site specific fuel analysis for process fuel gas (see Table A-9 in the GHG permit application). The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at §98.33(a)(2)(ii).
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at §98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2, site specific analysis of process fuel gas, and the actual heat input (HHV).

XIII. Low Profile Flare (PK-90050)

The low profile flare serves as a safety device designed to provide safe control of gases from the ethylene cracker and support units during periods of high pressure discharges during start-up and shutdown, emergency situations, and other large volume maintenance clearing. Additionally, the flare may control some low-pressure vent streams, such as "leak by" or fugitive emissions from safety relief and pressure control valves, sweep gas, and small volume maintenance activities. The flare's pilots are fueled by pipeline quality natural gas. The CO_2e emissions from the flare account for less than 2% of the total projects CO_2e emissions.

Step 1 – Identification of Potential Control Technologies

- *Carbon Capture and Storage (CCS)* – CCS is an available add-on control technology that is applicable for all of the sites affected combustion units.
- *Low Carbon Fuels* – The flare will use pipeline quality natural gas for the pilots and as supplemental fuel, if needed, to maintain appropriate vent stream heating value.

- *Good Combustion Practices and Maintenance* - Good combustion practices include appropriate maintenance of equipment and operating within the recommended heating value and flare tip velocity as specified by its design.

Carbon Capture and Storage

This add-on control technology was already discussed in detail in section IX. Based on the economic infeasibility and environmental detriment issues discussed in section IX above, CCS will not be considered further in this analysis.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Low-Carbon Fuel
- Good Combustion Practices

Use of low-carbon fuel, and good combustion practices are both considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Low-Carbon Fuel

The use of low-carbon fuel is economically and environmentally practicable for the proposed project. Combustion of gaseous fuel in lieu of higher carbon-based fuels such as diesel or coal reduces emissions of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing environmental benefits as well.

Good Combustion Practices

Good combustion practices effectively support the proper operation of the low profile flare as a standby control device.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the low profile flare:

- *Low Carbon Fuels* – The flare will combust pipeline natural gas in the pilots, natural gas will be used as supplemental fuel, if needed, to maintain combustion temperatures.
- *Good Combustion Practices and Maintenance* – Good combustion practices include appropriate maintenance of equipment, flare tip maintenance, operating within the recommended heating value, and flare tip velocity as specified by its design.

Using these BACT practices above will result in a BACT limit for the low profile flare of 27,000 tpy CO_2e. Chevron Phillips will demonstrate compliance with the CO_2 emission limit using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1, and the site specific fuel analysis for process fuel gas (see Table A-10 of the GHG permit application). The equation for estimating CO_2 emissions as specified in 40 CFR 98.253(b)(1)(ii)(A) is as follows:

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) * 1.102311$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (short tons/year).
0.98 = Assumed combustion efficiency of the flare.
0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).
n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p = Measurement period index.
44 = Molecular weight of CO_2 (kg/kg-mole).
12 = Atomic weight of C (kg/kg-mole).
$(Flare)_p$ = Volume of flare gas combusted during the measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term "$(MW)_p$/MVC" with "1".
$(MW)_p$ = Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
MVC = Molar volume conversion factor (849.5 scf/kg-mole).
$(CC)_p$ = Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98 Subpart C, Table C-2, site specific analysis of process fuel gas, and the actual heat input (HHV).

XIV. Emergency Generator Engines (PK-87010A, PK-87010B, PK-87010C, PK-87010D, PK-87010E, and PK-87010F)

Chevron Phillips will be authorized to install up to six emergency generators. The emergency generators shall have an aggregate power output not to exceed 4.0 MW, regardless of the number installed. The emergency generator engines proposed for use in Unit 1594 normally will operate at a low annual capacity factor - approximately one hour per week in non-emergency use. The engines are designed to use diesel fuel, stored in onsite tanks, so that emergency power is available for safe shutdown of the facility in the event of a power outage that may also include natural gas supply curtailments.

Step 1 – Identification of Potential Control Technologies

- *Carbon Capture and Storage (CCS)* – CCS is an available add-on control technology that is applicable for all of the sites affected combustion units.
- *Low Carbon Fuels* – Use of fuels containing lower concentrations of carbon generate less CO_2, than other higher-carbon fuels. Typically, gaseous fuels such as natural gas or high-hydrogen plant tail gas contain less carbon, and thus lower CO_2 potential, than liquid or solid fuels such as diesel or coal.
- *Good Combustion Practices and Maintenance* - Good combustion practices include appropriate maintenance of equipment and operating within the recommended air to fuel ratio recommended by the manufacturer.

<u>Carbon Capture and Storage</u>

This add-on control technology was already discussed in detail in section IX. Based on the economic infeasibility and environmental detriment issues discussed in section IX above, CCS will not be considered further in this analysis.

Step 2 – Elimination of Technically Infeasible Alternatives

- *Low Carbon Fuels* – Because the generators are intended for emergency use, these engines must be designed to use non-volatile fuel such as diesel. Use of volatile (low-carbon) natural gas or plant fuel gas in an emergency situation could exacerbate a potentially volatile environment that may be present under certain conditions, resulting in unsafe operation.

Therefore, Chevron Phillips proposes to use diesel fuel for the emergency generators, since non-volatile fuel must be used for emergency operations. The use of low-carbon fuel is considered technically infeasible for emergency generator operation and is not considered further for this analysis.

- *Good Combustion Practices and Maintenance* – Is considered technically feasible

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Only one option, good combustion practices and maintenance, has been identified for controlling GHG emissions from emergency generators; therefore, ranking by effectiveness is not applicable.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

The single option for control of CO_2 from emergency generators is to follow good combustion practices and maintenance.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the emergency generators:

- *Good Combustion Practices and Maintenance* – Good combustion practices for compression ignition engines include appropriate maintenance of equipment, periodic testing conducted weekly, and operating within the recommended air to fuel ratio, as specified by its design.

Using the BACT practices identified above results in a BACT limit of 275 tpy CO_2e. Chevron Phillips will demonstrate compliance with the CO_2 emission limit using the emission factors for diesel fuel from 40 CFR Part 98 Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * 0.001 * 1.102311$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of diesel fuel (short tons)
Fuel = Annual volume of the liquid fuel combusted (gallons). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).

CC = Annual average carbon content of the liquid fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at §98.33(a)(2)(ii).
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The proposed permit also includes an alternative compliance demonstration method, in which Chevron Phillips may install, calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2, site specific analysis of process fuel gas, and the actual heat input (HHV).

XV. Piping Fugitives from Fuel Lines

GHGs from piping fugitives within the ethylene cracker unit are generated primarily from plant fuel gas and natural gas lines. Other process lines in VOC service contain a minimal quantity of GHGs. Additionally, process lines in VOC service are proposed to incorporate the TCEQ 28LAER leak detection and repair (LDAR) program for fugitive emissions control. Therefore, since process lines contribute insignificant quantities of GHGs and since they are proposed in the governing permit for lowest achievable emission rate controls, process lines in VOC service in the proposed ethylene cracker unit are not considered further in this evaluation.

Step 1 – Identification of Potential Control Technologies

- *Leakless/Sealless Technology*
- *Instrument LDAR Programs*
- *Remote Sensing*
- *Auditory, Visual, and Olfactory (AVO) Monitoring*

Step 2 – Elimination of Technically Infeasible Alternatives

- *Leakless/Sealless Technology* – Leakless technology valves may be incorporated in situations where highly toxic or otherwise hazardous materials are present. Likewise, some technologies, such as bellows valves, cannot be repaired without a unit shutdown. Because plant tail gas and natural gas are not considered highly toxic nor hazardous materials, these gases do not warrant the risk of unit shutdown for repair and therefore leakless valve technology for fuel lines is considered technically impracticable. Sealless pumps and compressors, or seal systems venting to a control device such as the VDU or flare, are technically feasible for fuel gas service. However, since the fuel gas-specific piping lines system in the proposed ethylene cracker plant do not include pumps or compressors, this technology is irrelevant and therefore considered technically impracticable.

- *Instrument LDAR Programs* – Is considered technically feasible.
- *Remote Sensing* – Is considered technically feasible.
- *AVO Monitoring* – Is considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Instrument LDAR programs and remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[10] The most stringent LDAR program, 28LAER, provides for 97% control credit for valves, flanges, and connectors.

As-observed audio and visual observations (AVO) methods are generally somewhat less effective than instrument LDAR and remote sensing, since they are not conducted at specific intervals. However, since pipeline natural gas is odorized with very small quantities of mercaptan, as-observed olfactory observation is a very effective method for identifying and correcting leaks in natural gas systems. Due to the pressure and other physical properties of plant fuel gas, as-observed audio and visual observations of potential fugitive leaks are likewise moderately effective.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Although instrument LDAR and/or remote sensing of piping fugitive emissions in fuel gas and/or natural gas service may be somewhat more effective than as-observed AVO methods, the incremental GHG emissions controlled by implementation of the 28LAER or a comparable remote sensing program is 4,000 ton CO_2e per year, or less than 0.3% of the total project's proposed CO_2e emissions. Accordingly, given the costs of installing 28LAER or a comparable remote sensing program when not otherwise required, these methods are not economically practicable for GHG control from components in fuel gas service.

Step 5 – Selection of BACT

Based on the economic impracticability of instrument monitoring and remote sensing for fuel gas piping components, Chevron Phillips proposes to incorporate as-observed AVO as BACT for the

[10] 73 FR 78199-78219, December 22, 2008.

piping components in the new ethylene cracker plant in fuel gas and natural gas service. The proposed permit contains a condition to implement an AVO program on a weekly basis.

XVI. Process Line Fugitives

Process lines in VOC service contain a minimal quantity of GHGs. Additionally, process lines in VOC service are proposed to incorporate the TCEQ 28LAER leak detection and repair (LDAR) program for fugitive emissions control in the Nonattainment New Source Review (NNSR) permit to be issued by TCEQ. Therefore, since process lines contribute insignificant quantities of GHGs, less than 1% of total project emissions, and since they are proposed in the governing permit for lowest achievable emission rate controls, process lines in VOC service in the proposed ethylene cracker unit are not considered further in this evaluation. EPA concurs with Chevron Phillips assessment that using the TCEQ 28LAER[11] LDAR program is an appropriate control of GHG emissions. As noted above, LDAR programs would not normally be considered for control of GHG emissions alone due to the negligible amount of GHG emissions from fugitives, and while the existing LDAR program is being imposed in this instance, the imposition of a numerical limit for control of those negligible emissions is not feasible.

[11] The boilerplate special conditions for the TCEQ 28LAER LDAR program can be found at http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/bpc_rev28laer.pdf. These conditions are included in the TCEQ issued NSR permit.

XVII. Threatened and Endangered Species

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant, Chevron Phillips, and their consultant, SWCA Environmental Consultants ("SWCA"), and reviewed by EPA.

The action area for this project covers a three-mile radius around the construction footprint of the existing facility and extends into Harris and Chambers Counties, Texas. A draft BA has identified thirteen (13) species as endangered or threatened in Harris and Chamber Counties, by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD) and is listed in the table below:

Federally Listed Species for Harris and Chambers Counties	Scientific Name	Harris County	Chambers County
Smalltooth Sawfish	*Pristis pectinata*	X	X
Green Sea Turtle	*Chelonia mydas*	X	X
Kemp's Ridley Sea Turtle	*Lepidochelys kempii*	X	X
Leatherback Sea Turtle	*Dermochelys coriacea*	X	X
Loggerhead Sea Turtle	*Caretta caretta*	X	X
Hawksbill Sea Turtle	*Eretmochelys imbricate*		X
Louisiana Black Bear	*Ursus americanus luteolus*	X	X
Red Wolf	*Canis rufus*	X	X
Piping Plover	*Charadrius melodus*		X
Whooping crane	*Grus americana*	X	
Red-cockaded woodpecker	*Picoides borealis*	X	
Houston toad	*Bufo houstonensis*	X	
Texas prariedawn	*Hymenoxys texana*	X	

EPA has determined that the proposed permit will have no effect on any of the thirteen (13) listed species, as the occurrence of any of these species within the action area of the facility is highly improbable. The piping plover, whooping crane and red-cockaded woodpecker do not have suitable habitat within the action area, and are highly unlikely to occur in the vicinity of the Project. The green sea turtle, hawksbill sea turtle, Kemp's ridley sea turtle, leatherback sea turtle, loggerhead sea turtle, and smalltooth sawfish are marine species and would not occur near the

Project; these species are also not expected to be impacted indirectly, or through impacts to water quality. The Louisiana black bear, and red wolf are not found in the vicinity of the action area, and would not be impacted by the Project. The action area does not include any essential fish habitat or designated critical habitat for federally listed threatened or endangered species, and the Texas Natural Diversity Database includes no elements of occurrence for any rare, threatened, or endangered species. Indirect effects resulting from emissions, such as acidification and eutrophication, are unlikely to occur; therefore, protected species and their habitats will not likely be impacted.

Because of EPA's "no effect" determination, no further consultation with the USFWS and NMFS is needed.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on endangered species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XVIII. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on a cultural resource report prepared by SWCA submitted on June 12, 2012. Before that report was submitted to EPA, the Texas Historical Commission provided Chevron Phillips written concurrence on the report and its conclusion that no such properties are present on March 1, 2012. As part of EPA's obligations for consultation under NHPA Section 106, on October 12, 2012, EPA sent letters to twenty-seven (27) tribes with a historic interest in Texas to inquire whether any of them were interested in participating as consulting parties in the Section 106 process.

SWCA performed an archaeological survey of the area of potential effect (APE) which is approximately 455 acres of land within and adjacent to the construction footprint of the existing plant. The archaeological survey included a pedestrian survey and shovel testing of the property. SWCA also conducted a desktop review on the archaeological background and historical records within a 1-mile radius of the APE. Based on the results from the archaeological survey, no resources were found within the proposed construction footprint that would indicate the potential of archaeological resources or historical properties present. Based on the information provided from the desktop review, no archaeological resources or historic structures were found within the 1-mile radius of the APE.

After considering the report submitted by the applicant, EPA Region 6 determines that because no historic properties are located within the APE and that a potential for the location of archaeological resources within the construction footprint itself is low, issuance of the permit to Chevron Phillips will not affect properties potentially eligible for listing on the National Register.

EPA will provide a copy of this report to the State Historic Preservation Officer for consultation and concurrence with this determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties.

XIX. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGS at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XX. Conclusion and Proposed Action

Based on the information supplied by Chevron Phillips, our review of the analyses contained the TCEQ PSD Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue Chevron Phillips a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

APPENDIX

Annual Facility Emission Limits

Annual emissions, in tons per year (TPY) on a 12-month total, rolling monthly, shall not exceed the following:

Table 1. Facility Emission Limits

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
H-10100 H-10200 H-10300 H-10400 H-10500 H-10600 H-10700 H-10800	H-10100 H-10200 H-10300 H-10400 H-10500 H-10600 H-10700 H-10800	Steam Cracking Furnaces	CO_2	206,000[3]	1,579,000[4]	Furnace Gas Exhaust Temperature ≤ 350 °F. See permit condition III.A.1.j.
			CH_4	11.9[3]		
			N_2O	2.4[3]		
B-83010	B-83010	VHP Boiler	CO_2	127,000		Minimum Thermal Efficiency of 77%. See permit condition III.A.1.l.
			CH_4	6.5		
			N_2O	1.1		
PK-90060	PK-90060	VDU	CO_2	2,400	2,400	Use of Low Carbon Fuel and Good Combustion Practices. See permit condition III.A.2.c. - i.
			CH_4	0.046		
			N_2O	0.0046		
PK-90050	PK-90050	Low Profile Flare	CO_2	27,000	27,000	Use of Low Carbon Fuel and Good Combustion Practices. See permit condition III.A.3.c. and f.
			CH_4	2.1		
			N_2O	0.42		
PK-87010A PK-87010B PK-87010C PK-87010D PK-87010E PK-87010F	PK-87010A PK-87010B PK-87010C PK-87010D PK-87010E PK-87010F	Emergency Generator Engines[5]	CO_2	274	275	Use of Good Combustion Practices. See permit condition III.A.4.c.
			CH_4	0.011		
			N_2O	0.002		
F-1594	F-1594	Fugitive Process Emissions	CH_4	Not Applicable	Not Applicable	Implementation of LDAR/AVO program. See permit condition III.A.5.
Totals[6]			**CO_2**	**1,600,000**	**CO_2e 1,615,000**	
			CH_4	**416**		
			N_2O	**18**		

1. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
2. Global Warming Potentials (GWP): CH_4 = 21, N_2O = 310
3. The GHG Mass Basis TPY limit for the steam cracking furnaces applies to each unit and cannot be exceeded for any individual unit.
4. The compliance emission cap applies to the eight steam cracking furnaces, includes decoking activities, and the VHP Boiler.
5. Up to 6 generators are allowed however, total power output will not exceed 4.0MW for all generators combined.
6. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.