Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the BASF FINA Petrochemicals LP (BFLP), NAFTA Region Olefins Complex

Permit Number: PSD-TX-903-GHG

April 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 March 15, 2011, BASF submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions from a proposed project at the existing Port Arthur facility in Jefferson County, Texas. In connection with the same proposed project, BASF submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on March 14, 2011. The project at the Port Arthur facility proposes adding a tenth ethylene cracking furnace to the existing furnace bank, and modifying existing sources to efficiently combust hydrogen and to make up facility steam requirements from the loss of recovery capacity from cracking ethane (gas) feed stocks. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) in support of the draft air permit to authorize the construction and modification of air emission sources at the BFLP 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 demonstrating that the proposed permit conditions meet all applicable legal and regulatory requirements.

EPA Region 6 concludes that BASF'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 EPA requested and provided by BASF and/or its consultants, 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 (FIP) 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)
Texas Commission on Environmental Quality (TCEQ)
P.O. Box 13087, Austin, TX 78711-3087

IV. Facility Location

The BFLP plant is located in Jefferson County, Texas. This area is currently designated "attainment" for all NAAQS. The nearest Class I area is the Breton National Wildlife Refuge, which is located well over 100 km from the site. The geographic coordinates for this facility are as follows:

Latitude: 29.99107
Longitude: -93.992672

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

Figure 1. BFLP Facility Location

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

EPA concludes BASF's application is subject to PSD review for the pollutant GHGs, because the project would lead to an emissions increase of GHGs for a facility in excess of the emission thresholds described at 40 CFR § 52.21 (b)(23) and (49)(iv). As a result of the proposed project, GHG emissions will increase above the established thresholds of zero TPY on a mass basis and 75,000 TPY on a CO_2e basis. BASF calculated a CO_2e emissions increase of 915,576.8 TPY for the proposed project. Additionally, as part of any PSD applicability determination, to determine if the modification was major, the applicant provided a 5 year contemporaneous change analysis and netting calculations that demonstrated the project could not net out of PSD. 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.

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; hereinafter "GHG Permitting Guidance"). 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 BACT 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 PSD review for non-GHG regulated NSR pollutants that will be addressed in the permit sought from TCEQ.

Accordingly, under the circumstances of this project, the State will issue the non-GHG portion of the permit and EPA will issue the GHG portion.[1] As the permitting authority for regulated NSR pollutants other than GHGs, TCEQ has determined the modification is subject to PSD review for non-GHG pollutants. At this time, TCEQ has not issued the PSD permit amendment for the non-GHG pollutants.

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow BASF to add a 10th ethylene cracking furnace to the existing furnace bank, and modify other existing supporting units to produce utilities (electricity and steam) consumed by the site from multiple fuel streams, including produced high hydrogen gas. The 10th furnace will be capable of cracking multiple hydrocarbon feedstocks, but will be optimized to handle ethane gas. The energy required for cracking gaseous feedstocks is inherently less than that required for cracking liquids, and thus the ethylene furnace will fire at a reduced rate while cracking gaseous feedstocks. The reduced rate will limit the amount of heat

[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

recovery and subsequent steam generation that would otherwise take place while the unit is cracking liquid feedstocks. The loss in heat recovery steam generation capacity under the gaseous operating mode will be supplemented by existing support facilities. For this reason, the permit authorizes modifications to existing support facilities to provide steam needed to operate other plant equipment/processes while cracking gaseous feedstocks. The ethane feedstock will also increase the facilities production of hydrogen, a secondary product resulting from the ethylene cracking process. In addition to adding the furnace, this project involves modifying the steam generating facilities to permit the combustion of any excess produced hydrogen. The permittee outlined three operating scenarios for utilization of the hydrogen gas stream. When economically feasible, the hydrogen will be consumed in the package boilers and the cogeneration units. When there is a market for hydrogen product, it would be sold to the neighboring TOTAL Refinery or, alternatively, to a third party. With this construction permit, BASF intends to increase the total production of ethylene at the BFLP facility to 2.87 billion pounds per year. Furnace 10 (N-16) will be capable of producing 420,000,000 pounds of ethylene per year, based on maximum production from naphtha feed. Ethane will produce less ethylene. The proposed permit, upon final issuance, will apply to all operating conditions including normal operations, maintenance, start-up, and shutdown.

GHG Emissions

The facility is permitted to utilize several different gaseous fuel stocks all of which will produce CO_2, CH_4, and N_2O emissions (GHG's) at differing rates as a result of the normal combustion process. In properly tuned units, nearly all of the fuel carbon (99.9 percent) in the fuel gas is converted to CO_2 during combustion. This conversion is relatively independent of boiler or combustor type. Fuel carbon not converted to CO_2 results in CH_4, CO, and/or VOC emissions and is due to incomplete combustion. Even in units operating with poor combustion efficiency, the amount of CH_4, CO, and VOC produced is insignificant compared to CO_2 levels. Typically, conditions that favor formation of N_2O also favor emissions of methane. Formation of N_2O emissions are minimized when combustion temperatures are kept high (above 1,475 ^{o}F) and excess oxygen is kept to a minimum (less than 1 percent). Methane emissions are highest during low-temperature combustion or incomplete combustion, such as the start-up or shut-down cycles.

VII. Applicable Emission Units & Permit Limits and Conditions

The majority of the contribution of GHGs associated with the project is from combustion sources (i.e., cracking furnace, two steam package boilers, and gas turbine auxiliary duct burners). EPA reviewed available GHG PSD permitting precedent including the RACT/BACT/LAER Clearinghouse. EPA did not identify any other issued GHG permits for ethylene production facilities, or facilities that had similar operations and equipment. The BACT analyses and other technical information in BASF's application are incorporated into this Statement of Basis.

Fuels BACT

Inherent to the ethylene production process is the liberation of excess hydrogen atoms from the saturated feedstocks. The hydrogen is used to produce a hydrogen-rich product stream at the plant. The hydrogen byproduct is beneficial for several purposes and is slated to be transferred, marketed, or combusted as determined by contracts that are made for any produced hydrogen during any given period. Any of the hydrogen-rich product stream that is not slated to fulfill contract commitments will be utilized to the maximum extent possible by the plant equipment as fuel to supplement operational Btu requirements. Combusting un-contracted, uncommitted, or excess produced hydrogen is a component of BACT for limiting GHGs from affected combustion units.

Average parameters have been established for all fuels that the Permittee proposed to combust in various emission units at the site, as identified in Table 2 of the proposed permit. The average parameters are based on an analysis of the fuel giving the high heating value (HHV), molecular weight, the carbon components, and their weight percent. Calculations were then performed to derive a lb - CO_2/MMBtu value. The values are shown in Table 2 of the proposed permit.

Carbon Capture and Sequestration

Carbon Capture and Sequestration (CCS) is an available add-on control technology that is applicable for all of the site's affected combustion units. The evaluation of the technology is significantly different from the remaining energy efficiency and operational control measures considered below, and therefore for brevity it is considered separately.

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. BASF initially objected to recognizing CCS technology as a viable control option for their specific industry based on the fact it was not explicitly cited in the GHG Permitting Guidance. However, the unit operations occurring at the site are closely related or share inherent process operations and parameters with examples cited in the text. Further, the examples cited in the guidance document are not exhaustive, and EPA has discretion in determining which large emitting facilities, for which the BASF facility certainly is, should require an analysis of CCS.

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.[2] 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 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 BASF.

BASF provided supplemental application materials to address EPA concerns. BASF 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 cost. The majority of the cost was attributed to the capture and compression facilities that would be required. The total cost of CCS for only the furnace would be $24,000,000 per year. If CCS was applied to the package boilers and cogeneration facilities, total annual cost would be about $130,000,000 per year. The capital cost of the project annualized, assuming 15 year equipment life and 7% interest rate, is approximately $7,500,000 per year. Accordingly, the addition of CCS would represent a 3-to-17 fold increase in the total cost of the project. That cost exceeds the threshold that would make the project economically unviable. EPA Region 6 reviewed BASF'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, and thus CCS has been eliminated as BACT for this project.

[2] See *Report of the Interagency Task Force on Carbon Capture and Storage* available at http://www.epa.gov/climatechange/policy/ccs_task_force.html

Fuel Combustion Units (N-16, N-24A, N-24B, N-20A, and N-20B)

All of the units in this section share common parameters or requirements with respect to the analysis of BACT for efficiency and operational controls for the control of GHG emissions, and have therefore been grouped for the purposes of this portion of the review.

As part of the PSD review, BASF provides in the GHG permit application a 5-step top-down BACT analysis for the 10^{th} furnace project. EPA has reviewed BASF's BACT analysis for the above referenced fuel combustion units, 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

To maximize thermal efficiency at the BFLP plant, the following thermal efficiency measures have been identified and are currently implemented for the existing cracking furnaces, package boilers, and combustion turbine duct burners. These measures will continue to be implemented and will be incorporated into the 10^{th} furnace design as well. These technologies include the following:

- *Oxygen Trim Control* – Monitoring of oxygen concentration in the flue gas is conducted, and the inlet air flow is adjusted to maximize thermal efficiency.
- *Economizer* – Use of heat exchanger to recover heat from the exhaust gas to preheat incoming Steam Drum feedwater to attain industry standard performance (IMO) for thermal efficiency.
- *Blowdown Heat Recovery* – Use of a heat exchanger to recover heat from Steam Drum blowdown to preheat feedwater results in an increase in thermal efficiency.
- *Condensate Recovery* – Return of hot condensate for use as feedwater to the Steam Drum. Use of hot condensate as feedwater results in less heat required to produce steam, thus improving thermal efficiency.
- *Periodic Tune-up* – The combustion unit burners are tuned periodically to maintain optimal thermal efficiency.
- *Use of Product Hydrogen as a Fuel* – Partial replacement of natural gas (methane) with hydrogen (produced as a product in the ethane cracking process) reduces CO_2 emissions since combustion of hydrogen does not produce CO_2.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible. Oxygen trim control, economizers, waste heat steam generation, condensate return, and blowdown heat recovery are all used on the existing fuel combustion units at the BFLP plant. Because these technologies are already proposed in the design and/or implemented in existing units, ranking by effectiveness (Step 3) and a subsequent evaluation of each technology (Step 4) was not considered necessary for the BACT determination.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technologies not already included in the proposed combustion units design in order of most effective to least effective include:

- *Use of Product Hydrogen as a Fuel* – Substitution of pure hydrogen for natural gas (methane) results in essentially 100% control of the GHG emissions that would otherwise be emitted by each pound of methane replaced. However, the actual effectiveness is dependent upon the hydrogen and methane content of the hydrogen-rich product stream and the availability of this stream for use as fuel.
- *Periodic tune-up* – Currently, periodic tune-ups of the existing combustion units are performed as needed. The effectiveness of this control option cannot be directly quantified, and is therefore ranked as the least effective alternative.

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

- *Use of Product Hydrogen as a Fuel* – BASF's business plans call for sale of the produced hydrogen-rich stream. Market conditions will dictate which feeds are used, and the resulting quantity of hydrogen-rich product will vary as the feed composition varies. Market conditions, and subsequent contracts for product, will also dictate how much hydrogen can be sold. Therefore, a requirement to use hydrogen as fuel in place of natural gas when available and not sold as product is a viable operating practice. This same operating practice is considered technically and economically feasible for the 10th Furnace based on its successful implementation on the existing furnaces.
- *Periodic tune-up* – The furnace operations will include preventive maintenance checks of fuel gas flow meters annually, preventive maintenance check of oxygen control analyzers quarterly, cleaning of burner tips on an as-needed basis, and cleaning of convection section finned tubes on an as-needed basis. (Note: These activities insure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement, although convection cleaning has shown improvements in the 0.5 to 1.5% range.)

Step 5 – Selection of BACT

Oxygen trim control, use of an economizer, condensate recovery, and boiler blowdown heat recovery are currently utilized on the existing applicable units at the BFLP plant to maximize efficiency and thus reduce GHG emissions. These control practices are also included in the 10th Furnace design and are thus part of the proposed BACT for the listed combustion units, as well as the following additional BACT practices:

- *Implement all current practices* – Install, utilize, and maintain oxygen trim control, condensate recovery, boiler blowdown and process heat recovery, and economizers on all the combustion units where applicable.

- *Use of Product Hydrogen as a Fuel* – Incorporate the 10th Furnace into the existing plant furnace fuel gas system that utilizes available hydrogen not already used as fuel in the Cogeneration Unit duct burners and Package Boilers.
- *Periodic tune-up* – Calibrate and perform preventive maintenance on the fuel flow meter once per year and oxygen control analyzers once per quarter.

<u>Ethylene Cracking Furnace (N-16)</u>

The 10th Cracking Furnace will be added onto the existing hydrocarbon cracking train consisting of nine furnaces. The new furnace will be optimized to crack gaseous feed stocks such ethane, propane, and butane, while retaining the capability to crack traditional liquid feedstocks such as naphtha. The furnace is designed to produce approximately 36,200 lb/hr of ethylene from naphtha feed, and slightly higher amounts per hour from the gaseous feedstocks due to inherent efficiencies gained from cracking less complex molecules. The furnace should produce approximately 45,000 lb/hr of ethylene from gaseous (ethane) feed. The furnace will be switched freely between gaseous and liquid feeds. Further efficiencies are gained from an approximately 40% reduction in dilution steam requirements for cracking ethane gas. The dilution steam is introduced into the furnace with the process material to reduce coke formation and buildup on the heat transfer coils within the convection zone of the furnace. The steam enables longer run times and enhances overall furnace efficiency since the coke deposition limits effective heat transfer of the coils over time. The new furnace will have a maximum firing rate of 498 MMBtu/hr and will use either, natural gas, high pressure cracker offgas, low pressure cracker offgas, or high hydrogen content gas as fuel. In addition, the furnace is plumbed to enable the co-firing of any combination of these fuels to produce heat in the most economical means possible. The applicant has proposed that the furnace be equipped with a Selective Catalytic Reduction (SCR) unit to achieve BACT levels of NO_X emissions in the flue gas. The total annual production of ethylene authorized by this permit is 2.87 billion pounds.

As part of the PSD review, BASF provides in the GHG permit application a 5-step top-down BACT analysis specific for the proposed furnace. EPA has reviewed BASF's BACT analysis for the furnace, 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

- *Steam Generation from Process Waste Heat* – Use of heat exchangers to recover heat from the process effluent to generate high pressure steam. The high pressure steam is then superheated by heat exchange with the furnace exhaust gas, thus improving thermal efficiency.
- *Periodic Decoking of Furnace Coils* – An unavoidable side reaction of the cracking process is coke formation in the tubes of the furnace radiant coils. The presence of the coke decreases the transfer of heat in the furnaces. Coke deposits act as insulation requiring an increase in the

amount of fuel needed to produce more heat for transfer through the coil walls. Thus, periodic decoking of the coils improves thermal efficiency.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible, are all used on the existing cracking furnaces at the BFLP plant and have been incorporated into the proposed 10th Furnace design. Because these technologies are already proposed, ranking by effectiveness (Step 3) and a subsequent evaluation of each technology (Step 4) was not considered necessary for the BACT determination.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Not Applicable (as noted above)

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

Not Applicable (as noted above)

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the furnace:

- *Steam Generation from Process Waste Heat* – Use heat exchangers to recover waste heat from the process effluent to generate high pressure steam. Waste heat will be recovered regardless of operational mode.
- *Periodic Decoking of Furnace Coils* – Decoke the 10th Furnace coils to maintain efficient operation. (Note: This condition varies depending on the type of feed and furnace utilization; therefore, a specific decoke frequency cannot be specified, although the permitting parameter range is 4 to 13 decoke events per year.)
- *Energy Efficient Operation* - Continuously monitor the flue gas exhaust temperature and limit temperature to less than or equal to 309 ^{o}F on a 365-day total, rolling average basis.
- *Continuous Emissions Monitoring System (CEMS)* - As an alternative to monitoring the flue gas exhaust temperature to ensure efficient operation, BASF 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.

<u>**Steam Package Boilers (N-24A and N-24B)**</u>

The two package boilers are identical. The firing rate is limited to 425.4 MMBtu/hr for each boiler. The boilers have a 380 MMBtu/hr annual average. Each boiler exhaust is equipped with SCR. The boilers are limited to firing refinery fuel gas (RFG) no more than 8,760 hours per year combined.

BASF will demonstrate operational BACT for the unit by calculating the thermal efficiency of the unit monthly and maintaining a 77% thermal efficiency on a 12-month rolling average basis. Efficiency will be demonstrated by the following equation:

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

<u>Gas Turbine Auxiliary Duct Burners (N-20A and N-20B)</u>

The cogeneration unit emissions consist of emissions from the turbines and from the duct burners in the heat recovery steam generating units (HRSG). The cogeneration train units 1 and 2 (N-20A and N-20B) are each comprised of a General Electric frame 6B Turbine and a 310.4 MMBtu/hr, based on the HHV of fuel, duct burner, and selective catalytic reduction (SCR). Only the duct burners are affected by the proposed modification. There will be no increase in the maximum allowable duct burner firing rates associated with the proposed modification; however, the increased utilization of the duct burners due to the shift in the steam load will result in an increase in actual GHG emissions when methane (natural gas) is used as the fuel to provide the increased steam.

BASF will demonstrate operational BACT for the units by calculating the thermal efficiency of the units monthly and maintaining a 60% thermal efficiency on a 12-month rolling average basis. Efficiency will be demonstrated by the following equation:

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

<u>Decoking Drum (N-18)</u>

Decoking will be done using existing decoking facilities. Emissions from periodic decoking of the coils in the 10th Furnace are emitted to the atmosphere through the existing separator drum. The GHG emissions consist of CO_2 that is produced from combustion of the coke build up on the coils. The estimated annual CO_2 emission rate from decoking of the furnace is 571 TPY. The estimated emissions are based on the emissions expected from 13 decoking events. The furnace will be decoked no more than 13 times on a 12 month rolling basis. The emissions from decoking are a negligible contribution to the total GHG emissions; however, for completeness, it is addressed in this BACT analysis.

Step 1 – Identification of Potential Control Technologies

There are no available technologies that have been applied to furnace decoke drums to control CO2 emissions once generated. Minimizing coke formation through proper design and operation of the furnace to minimize the amount of CO2 produced and/or the required decoking frequency are the only technically feasible means of minimizing emissions.

Step 2 – Elimination of Technically Infeasible Alternatives

Proper furnace design and operation to minimize coke formation is considered technically feasible for the 10th Furnace.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Only one technology, 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 unavoidable requirement to periodically take a cracking furnace off-line for decoking results in loss of production from the furnace. 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

Proper furnace design and operation to minimize coke formation to the maximum extent possible will be utilized for the 10th Furnace out of economic necessity. BASF elects to limit GHG emissions from decoking to an estimated 571 TPY. Emissions from decoking amount to less than 0.1% of the total GHG emissions from the facility and are insignificant.

Process Fugitives (F-1)

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. The additional methane emissions from process fugitives have been conservatively estimated to be 34 TPY as CO_2e. This is a negligible contribution to the total GHG emissions for the project and accounts for less than 0.01% of the total GHG emissions for the facility; however, for completeness, they are addressed in this BACT analysis.

Step 1 – Identification of Potential Control Technologies

The only identified control technology for process fugitive emissions of GHGs is use of a leak detection and repair (LDAR) program. LDAR programs vary in stringency as needed for control of VOC emissions; however, due to the negligible amount of GHG emissions from fugitives, LDAR programs would not be considered for control of GHG emissions alone. As such, evaluating the relative effectiveness of different LDAR programs is not warranted.

Step 2 – Elimination of Technically Infeasible Alternatives

LDAR programs are a technically feasible option for controlling process fugitive GHG emissions.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

As stated in Step 1, this evaluation does not compare the effectiveness of different levels of LDAR programs.

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

Although technically feasible, use of an LDAR program to control the negligible amount of GHG emissions that occur as process fugitives would be cost prohibitive. However, if an LDAR program is being implemented for VOC control purposes, it will also result in effective control of the small amount of GHG emissions from the same piping components. BASF uses TCEQ's 28LAER LDAR program to minimize process fugitive VOC emissions at the plant, and this program has also been proposed for the additional fugitive VOC emissions associated with the project. 28LAER is TCEQ's most stringent LDAR program, developed to satisfy LAER requirements in ozone non-attainment areas.

Step 5 – Selection of BACT

Due to the negligible amount of GHG emissions from process fugitives, the only available control is the implementation of an LDAR program. BFLP will implement TCEQ's 28LAER[3] LDAR program for VOC BACT purposes, which will also effectively minimize GHG emissions. Therefore, the proposed VOC LDAR program more than satisfies GHG BACT requirements when monitoring for methane. However, since numeric limits for application of the LDAR are not practically enforceable, such limits will not be included in the permit.

HFC Fugitives (HFC-FUG)

New hydrofluorocarbons (HFC) containing equipment for the tenth furnace project consists of a continuous emissions monitoring system (CEMS) cabinet AC with a 22 ounce charge of R-422D, and six new 6-ton electrical equipment cooling units each with a 12 lb. charge of R-410A. The two refrigerants are a blend of several HFCs and the global warming potentials (GWP) for each are determined based on 40 CFR Part 98 Subpart OO. R-422D and R-410A have a calculated GWP of 2,232 and 1,725 respectively. If all of the refrigerant contained in the equipment were to be released all at once, it would be equivalent to 52.37 tons of CO_2e. Releases of HFC would only occur during an emergency event or malfunction, neither of which are permitted emission events and thus no emission limit is required. Self contained refrigeration units are shipped fully charged in closed loop systems to ensure no refrigerant is leaked. As with all equipment, age, thermal cycling, and materials fatigue can eventually cause system failures and a subsequent release of

[3] 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.

refrigerant chemicals to the environment. However, the Clean Air Act has requirements specific to HFC containing equipment under section 608, so the permit will include those conditions required to reduce HFC fugitive emissions, specifically having equipment serviced by EPA certified technicians, maintaining all service records for the equipment, including all mass balances for adding and removing refrigerants for the units during services, and promptly repairing leaking equipment when leak rates of greater than 35% occur.

VIII. 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 and reviewed by EPA. Further, EPA designated BASF as its non-federal representative for purposes of preparation of the BA and for conducting informal consultation.

The project and defined action area are solely within Jefferson County, the proposed project site site is located on the border between the Neches River Basin and the Neches-Trinity Coastal Basin- approximately 1.8 miles north of the Neches River at its closest point and approximately 1.1 miles east-southeast from Sabine Lake.

A draft BA identified five species, four turtles and a bird species, that are on the USFWS list of endangered species as having the potential to occur in Jefferson County, Texas. The endangered species are listed in the table below:

USFWS List of Endangered Species for Jefferson county, Texas

Common Name	Scientific Name	Species Group
piping plover	*Charadrius melodus*	bird
green sea turtle	*Chelonia mydas*	reptile
hawksbill sea turtle	*Eretmochelys imbricata*	reptile
Kemp's ridley sea turtle	*Lepidochelys kempii*	reptile
leatherback sea turtle	*Dermochelys coricea*	reptile

The piping plover inhabit beaches, river islands and lakeshores and no known designated critical habitat for this species has been identified within sixteen (16) miles from the action area. The action area includes pasture land, mixed woodlands, marshland, open water, riverine and active and fallow agricultural land. While there is no known habitat within the action area, the potential exists that portions of the the action can area serve as a foraging habitat. Additionally, two small potential piping plover nesting habitat locations were located approximately 1.1 miles northeast of the action area, on Stewts and Humble Islands on Sabine Lake which are currently densely populated with other migratory birds including brown pelicans, white pelicans, black skimmers and multiple gull species.

For the green sea turtle, Kemp's ridley sea turtle, the leatherback sea turtle and hawksbill sea turtle, portions of Sabine Lake, the Intracoastal Water and the Neches River are included within the action area. However, due to the high degree of industrial, recreational development along the Neches River and the high traffic volume of cargo ships and barges, portions of Sabine Lake, the Intracoastal Water and the Neches River within the action area do not possess the preferred nesting or feeding habitat for any of these endangered turtle species and there is no known designated critical habitat located within at least 16 miles of the project site. There have been infrequent observations of green sea turtle and Kemp's ridley sea turtle within areas of Sabine Lake and the closest known occurrence of either species has been recorded more than 15 miles of the project site. No occurrences of the leatherback sea turtle or the hawksbill sea turtle has ever been recorded in the Neches River, Intracoastal Waterway or the Sabine Lake and the potential occurrence for either species is highly unlikely.

Based on the information provided in the draft BA, EPA concludes that the proposed PSD permit allowing BASF to construct the ethylene cracker facility will have no effect on the leatherback sea turtle or the hawksbill sea turtle because of their lack of occurrence in the any of the bodies of water that may be affected by the plant. However, because of the infrequent occurrence of the green sea turtle and Kemp's ridley sea turtle in Lake Sabine, EPA has determined that this project may affect, but is not likely to adversely affect the green sea turtle and Kemp's ridley sea turtle. For the piping plover, due to the fact that portions of the the action area may serve as a foraging habitat and the potential that Stewts and Humble islands may serve as a nesting habitat for this bird species, EPA has determined that this project may affect, but is not likely to adversely affect the piping plover. Because of EPA's "may effect" determination, EPA and BASF (as EPA's designated non-federal representative) have entered into informal consultation with the USFWS. By letter dated March 19**,** 2012, EPA initiated informal consultation with the Southwest Region, Houston, Clear Lake Ecological Services Field Office, of the USFWS by submitting copy of the draft BA and requesting USFWS's written concurrence with EPA's "not likely to adversely effect" determination.

IX. 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 Whitenton Group, Inc., BASF's consultant, submitted on July 5**,** 2011 to the Texas Historical Commission. Upon receipt of the report, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes were interested in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no tribal requests for participation as a consulting party or comments about the project.

EPA Region 6 determines this project will have no effect on properties eligible for the National Register. EPA provided a copy of this report to the State Historic Preservation Officer for consultation and concurrence with this determination on March 20, 2012. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties.

X. Environmental Justice

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive 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*) ("Knauf I").*This permitting action, if finalized, only authorizes emissions of GHGs and does not select environmental controls for any other pollutants. Climate change modeling and evaluations of risks and impacts is typically conducted for changes in emissions 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.

XI. Conclusion and Proposed Action

Based on the information supplied by BASF, 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 BASF 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 emissions, in tons per year (TPY) on a 365-day average, rolling daily, shall not exceed the following:

Table 1. Annual Facility Emission Limits

Unit ID	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
H-1000	N-16	Ethylene Cracking Furnace	CO_2	255.735	256,914	Flue Gas Exhaust Temperature ≤ 309 °F. See permit condition III.B.1.j.
			CH_4	14.2		
			N_2O	2.8		
B-7280 and B-7290	N-24A N-24B	2 Steam Package Boilers[4]	CO_2	420,095	421,399	Minimum Thermal Efficiency of 77%. See permit condition III.B.2.h.
			CH_4	22.0		
			N_2O	4.4		
GTG1-DB	N-20A	Gas Turbine Auxiliary Duct Burner	CO_2	117,786	118,329	Minimum Thermal Efficiency of 60%. See permit condition III.B.3.g.
			CH_4	6.5		
			N_2O	1.3		
GTG2-DB	N-20B	Gas Turbine Auxiliary Duct Burner	CO_2	117,786	118,329	Minimum Thermal Efficiency of 60%. See permit condition III.B.3.g.
			CH_4	6.5		
			N_2O	1.3		
D-1801	N-18	10th Furnace Decoking Drum Operations	CO_2	571	571	Proper furnace design and operation. See permit conditions III.B.1.f.
P-FUG	F-1	Fugitive Process Emissions	CH_4	Not Applicable	Not Applicable	Implementation of LDAR Program. See permit condition III.B.4.a.
Totals			**CO_2**	**911,451**	**CO_2e 915,542**	
			CH_4	**49**		
			N_2O	**10**		

1. Compliance with the annual emission limits (tons per year) is based on a 365-day average, rolling daily.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions only from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 21, N_2O = 310
4. The steam package boilers have a combined annual refinery fuel gas (RFG) firing limit equivalent to one boiler firing RFG at capacity for 8,760 hrs per year.