# Statement of Basis
Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for the Equistar Chemicals LP, La Porte Complex

Permit Number: PSD-TX-752-GHG

January 2013

This document serves as the Statement of Basis (SOB) 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 September 29, 2011, Equistar Chemicals, LP (Equistar) La Porte Complex submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions. In connection with the same proposed project, Equistar submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on September 22, 2011. The project at the La Porte Complex proposes to construct two new cracking furnaces and supporting equipment at the existing QE-1 Olefins unit. 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 Equistar, La Porte Complex.

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 Equistar’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 Equistar, 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 Equistar, La Porte Complex is located in Harris County, Texas, and this area is currently designated “nonattainment” for Ozone. The nearest Class 1 area is the Breton National Wildlife Refuge, which is located over 100 miles from the site. The geographic coordinates for this facility are as follows:

Latitude: 29º 42’ 23” North
Longitude: - 95º 03’ 40” West

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

Figure 1. Equistar Chemicals, La Porte Complex Location

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

EPA concludes Equistar'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 as described at 40 CFR § 52.21(b)(49)(iv). Under the project, increased GHG emissions will have a mass basis over zero tpy and $CO_2e$ emissions are calculated to exceed the applicability threshold of 75,000 tpy (Equistar calculates increases of GHGs emissions to be 602,659 tpy on a mass basis and 603,872 tpy $CO_2e$). 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

As the permitting authority for regulated NSR pollutants other than GHGs, TCEQ has determined the modification is subject to PSD review for CO, $PM_{10}$, and $PM_{2.5}$. At this time, TCEQ has not issued the PSD permit amendment for the non-GHG pollutants.

Accordingly, under the circumstances of this project, the TCEQ will issue the non-GHG portion of the 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 and non-attainment permits sought from TCEQ.

## VI. Project Description

The Olefins unit (QE-1) receives hydrocarbon feedstock where it is fed into pyrolysis furnaces. The pyrolysis furnaces, which are fired on natural gas and/or process gas, heat the feedstock to a high temperature where it cracks and reforms as alkenes or olefins. The proposed GHG PSD permit, if finalized, will allow Equistar to expand their Olefins unit (QE-1) by constructing two new cracking furnaces and supporting equipment at the existing facility at the La Porte Complex located in La Porte, Harris County, Texas. The modification increases the plant nominal ethylene production capacity from 875,000 tpy to 1,280,000 tpy. This equates to approximately 405,000 tons per year nominal additional capacity to produce ethylene. The plant also produces other products at varying capacities, but ethylene is the predominant product.

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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 process effluent from the furnaces is quenched and scrubbed with water. Pyrolysis gasoline is removed as a product during water scrubbing. The quenched gases are compressed, dried, and cooled prior to beginning a series of purification/distillation steps. A hydrogen rich stream from the final chilling step is further purified in a pressure swing absorber to produce hydrogen product.

The purification section consists of a demethanizer, deethanizer, acetylene recovery unit (ARU), depropanizer, methyl acetylene propadiene conversion unit (MAPD), debutanizer, C3 splitter, and C2 splitter. This equipment separates the process gas stream into acetylene, ethylene, propylene, mixed C4s, and pyrolysis gasoline (pygas) products. Ethane and propane recovered during distillation and separation are recycled as feedstock into the pyrolysis furnaces.

Periodically, coke (primarily carbon) deposited in the furnace tubes must be removed. The decoking operation consists of two steps, of which only the second produces GHG emissions:

- An initial steam purge which moves hydrocarbons and coke particles further into the process, then
- A burn step which produces CO and $CO_2$, and routes the vent stream including coke particles to a cyclone separator.

## VII. General Format of the BACT Analysis

The BACT analyses was 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" Best Available Control Technology Guidance Document* outlined in the 1990 draft U.S. EPA *New Source Review Workshop Manual*, BACT analyses take into account the energy, environmental, and economic impacts of the control options. Emission reductions may be determined through the application of available control techniques, process design, and/or operational limitations. Such reductions are necessary to demonstrate that the emissions remaining after application of BACT will not cause adverse environmental effects to public health and the environment.

Each of the emission units 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, decoking drum, and flares). These stationary combustion sources primarily emit carbon dioxide ($CO_2$), and small amounts of nitrous oxide ($N_2O$) and methane ($CH_4$). The site has some fugitive emissions from piping components, which contribute an insignificant amount of GHGs. The following devices are subject to this GHG PSD permit:

- Cracking Furnaces (QE1010B and QE1011B)
- Decoking Drum (QE1416FB)
- Flares (QE3050B and QE8050B)
- Fugitive Emissions (QEFUG)

## IX. Cracking Furnaces (QE1010B and QE1011B)

The Olefins unit expansion consists of two cracking furnaces (QE1010B and QE1011B). The furnaces are equipped with low NOx burners and selective catalytic reduction (SCR) systems to control NOx emissions. Furnace fuel is natural gas and may combust fuel gas containing hydrogen as a secondary fuel when practicable and available.

As part of the PSD review, Equistar provides in the GHG permit application a 5-step top-down BACT analysis for the three cracking furnaces. EPA has reviewed Equistar'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)* – CCS is an available add-on control technology that is applicable for all of the sites affected combustion units.
- *Hydrogen Fuel as Primary Fuel* – Hydrogen when burned has no potential for generation of $CO_2$ emissions.

- *Energy Efficient Design* – Equistar selected a furnace design that will maximize efficiency by incorporating the latest improvements in heat transfer and fluid flow to maximize the energy efficiency and energy recovery.
- *Fuel Selection* – 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 a hydrogen rich gas stream contain less carbon, and thus lower $CO_2$ potential, than liquid or solid fuels such as diesel or coal. Equistar, proposes to use a hydrogen rich gas stream as the secondary fuel for the cracking furnaces.
- *Best Operation Practices* – Best operation practices include periodic tune-ups and oxygen trim controls. The tune-ups will include instrument calibrations and cleaning of dirty or fouled mechanical parts. Oxygen trim control allows the excess oxygen to be controlled to optimum levels, thus allowing the furnace to operate at continuous high levels of efficiency.
- *$N_2O$ Catalysts* – $N_2O$ catalysts have been used in the nitric/adipic acid plants to minimize $N_2O$ emissions.
- *Post-combustion catalytic oxidation* – Post-combustion catalytic oxidation provides rapid conversion of a hydrocarbon into $CO_2$ and water vapor in the presence of available oxygen.

## Carbon Capture and Sequestration (CCS)

For purposes of a BACT analysis, carbon capture and sequestration (CCS) is classified as an add-on pollution control technology for “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] CCS involves the separation and capture of $CO_2$ from the combustion process flue gas, the captured $CO_2$ is then pressurized and transportation by pipeline or other means of transportation, if necessary, 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[3] below adopted from IPCC’s *Carbon Dioxide Capture and Storage* report:

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[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>

| 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) |

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 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

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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>

> 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.

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 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, except for $N_2O$ catalysts and post-combustion catalytic oxidation.

$N_2O$ catalysts have not been used to control $N_2O$ emissions from cracking furnace applications. In addition, the $N_2O$ concentrations present in the exhaust stream would make installation of $N_2O$ catalysts technically infeasible. $N_2O$ catalysts are eliminated as a technically feasible option for the proposed project.

The cracking furnace flue gas temperature is designed to have a range of 240 $^{o}$F to 320 $^{o}$F (116 $^{o}$C to 160 $^{o}$C). This temperature range is below the lowest operating temperature for catalytic oxidation. Typical low ends of operating temperature ranges for catalytic oxidation are 250 $^{o}$C or higher. Addition of post-combustion catalytic oxidation on the cracking furnaces for control of

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[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

[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

$CH_4$ is technically infeasible. Accordingly, post-combustion catalytic oxidation is eliminated as a technically feasible option for the proposed project.

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 CCS technologies are 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 Equistar.

**Step Two Summary for CCS for Equistar**

| 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 | Y* |
| | 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]

**Step 3** – Ranking of Remaining Technologies Based on Effectiveness

- Use of Hydrogen as Primary Fuel (100%)
- $CO_2$ capture and storage (up to 90%)
- Fuel Selection (>12%)
- Energy Efficient Design (4.9%)

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[8] U.S. Department of Energy, page 20-23, see note 7, supra.

- Best Operation Practices

Use of Hydrogen as the primary, and only fuel for the cracking furnace, would not produce any GHG emissions and thus is considered the most effective control method. $CO_2$ capture and storage is capable of achieving 90% reduction of produced $CO_2$ emissions and thus considered to be the second most effective control method. CCS controls 57% of $CO_2$ emissions when increases elsewhere from the CCS equipment are considered. Selecting to burn a lower carbon content fuel can reduce $CO_2$ emission by at least 12%. Energy efficient design reduces $CO_2$ emissions by a maximum reasonable 4.9% control. Best operation practices are 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

Use of Hydrogen as Primary Fuel

Hydrogen could be used as the only fuel for the cracking furnaces, providing 100% elimination of $CO_2$ from the flue gas, provided it was available, and the necessary firebox heat release and temperatures could be produced. The National Renewable Energy Laboratory (NREL) has determined that the net effect of using hydrogen as a fuel when produced by the most common means, steam methane reforming, is an overall increase in GHG emissions.[9] Therefore, while $CO_2$ emissions from the cracking furnaces may be reduced by use of hydrogen as the primary fuel, the collateral effect is that the hydrogen would need to be produced elsewhere and the most common means of production generates more $CO_2$ than is offset by the hydrogen combustion. Accordingly, use of hydrogen as the primary is eliminated based on negative environmental impact of these collateral increases in $CO_2$.

Carbon Capture and Sequestration

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

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[9] NETL publication, *Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming,* page 23, Conclusions. http://www.nrel.gov/docs/fy01osti/27637.pdf

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.[10] 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 Equistar.

Equistar 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. Equistar also asserts that implementing CCS is technically infeasible. The furnace exhaust streams are not high-purity, they contain approximately 3% or less $CO_2$ on an average annual basis. The recovery and purification of $CO_2$ from the stack gases would necessitate significant additional processing, including energy, and environmental/air quality penalties, to achieve the necessary $CO_2$ concentration for effective sequestration.

The analysis provided by the applicant demonstrates that CCS can be eliminated based on its economic, environmental, and energy costs. In its analysis, Equistar noted that it is in relatively close proximity to a $CO_2$ pipeline. The nearest existing pipeline identified by Equistar that may transport $CO_2$ is approximately 20 miles from the plant. The distance to the pipeline is calculated approximately based on the location of Denbury’s Green Pipeline located in Galveston County as seen from the National Pipeline Mapping System.[11] Equistar utilized the March 2010 National Energy Technology Laboratory (NETL) document *Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447*[12] to estimate the cost associated with the pipeline and associated equipment. Assuming that the $CO_2$ pipeline company would be able to receive the $CO_2$ stream, the estimated capital cost associated with

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

[11] http://www.npms.phmsa.dot.gov/

[12] See *Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs* available at http://www.netl.doe.gov/energy-analyses/pubs/QGESStransport.pdf

transport of the $CO_2$ to the pipeline is approximately $16,600,000. The operation and maintenance cost of the pipeline is $173,000 per year.[13]

The majority of the cost for CCS was attributed to the capture and compression facilities that would be required. The capital cost of CCS capture and compression installation would be more than $105,000,000. The total cost of CCS is therefore estimated to be more than $120,000,000 when the pipeline costs are added. Equistar's analysis shows that the addition of CCS capital costs to the current project would result in an increase of 25% - 50% in the capital costs for the project, which Equistar claims would make the project economically unviable. EPA Region 6 reviewed Equistar'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 as economically infeasible.

Economic infeasibility notwithstanding, Equistar asserts that CCS can have a collateral increase of National Ambient Air Quality Standards (NAAQS) pollutants. Implementation of CCS would increase emissions of GHGs, NOx, CO, VOC, $PM_{10}$, $SO_2$, and ammonia by as much as 30%. The proposed plant is located in an area of ozone non-attainment and the generation of additional NOx and VOC could have an adverse environmental impact. Equistar also indicated that carbon capture would result in an energy penalty of approximately 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. Accordingly, CCS could also be eliminated as BACT for this project based on these adverse environmental and energy impacts.

Fuel Selection

The use of low-carbon fuel is economically and environmentally practicable for the proposed project. Natural gas is the lowest emitting carbon fuel that could be relied upon for the proposed operation. Olefins plants produce gas streams that are suitable for introduction to a fuel gas system. These gases are primarily methane and hydrogen, along with occasional quantities of materials such as acetylene. The Olefins plant, QE-1 includes a demethanizer, which is a distillation column that separates methane from the process stream of heavier components. This is one of the primary sources of plant produced fuel gas. If flared as opposed to being used as a fuel, essentially all carbon content of the fuel gas would be converted to $CO_2$ with no beneficial use of the heating value of the flared gases. The furnaces may combust hydrogen rich fuel gas as

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[13] CCS pipeline costs estimated using the NETL E*stimating Carbon Dioxide Transport and Storage Costs, http://www.netl.doe.gov/energy-analyses/pubs/QGESStransport.pdf*

a secondary fuel when practicable and when available. The process produces hydrogen that may enter the commercial hydrogen market. If a portion of the produced hydrogen is not exported from the unit as a product, it may be used as a fuel to capture its heating value, thus offsetting some of the heat input that would otherwise come from natural gas or plant fuel gas. The availability of hydrogen for combustion in the furnaces is not assured. Further, combustion of natural gas and plant fuel gas in lieu of higher carbon-based fuels such as diesel and coal, 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.

Upon initial start-up, Equistar's furnaces are projected to have energy efficiencies during operation ranging from 91.8 to 93.8% (LHV), or 92.5 to 94.5% (HHV) which is above the 92% (HHV) theoretical maximum efficiency as reported in the 2008 EPA Energy Star publication.[14] Furnace design will incorporate the latest improvements in heat transfer and fluid flow to maximize the energy efficiency and energy recovery to provide a targeted 93.4% efficiency in transfer of heat into the process fluids. As furnaces of this type age, refractory and insulation degrade in performance, and convection section tubes become fouled, efficiency can degrade slightly. Equistar anticipates that thermal efficiency will decrease to no lower than 91% as an annual average in the late stages of the furnace life.

Best Operation Practices

Best operation practices effectively support the energy efficient design. Thus, the economic and environmental practicability related to energy efficient design also applies to the use of best operation practices.

**Step 5** – Selection of BACT

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

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[14] From *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry, An ENERGY STAR Guide for Energy and Plant Managers,* June 2008.
http://www.energystar.gov/ia/business/industry/ES_Petroleum_Energy_Guide.pdf?9b0b-33ce

| Company / Location | Process Description | Control Device | BACT Emission Limit / Requirements | Year Issued | Reference |
|---|---|---|---|---|---|
| BASF FINA Petrochemicals LP, NAFTA Region Olefins Complex<br>Port Arthur, TX | Ethylene Production | Energy Efficiency/ Good Design & Combustion Practices | GHG BACT for furnace limit flue gas exhaust temperature ≤ 309 °F.<br>365-day average, rolling daily | 2012 | PSD-TX-903-GHG |
| Williams Olefins LLC, Geismar Ethylene Plant<br>Geismar, LA | Ethylene Production | Energy Efficiency/Low-emitting Feedstocks/Lower-Carbon Fuels | Cracking heaters to meet a thermal efficiency of 92.5%<br>Ethane/Propane to be used as feedstock<br>Fuel gas containing 25% volume hydrogen on an annual basis | 2012 | PSD-LA-759 |
| Ineos Olefins & Polymers U.S.A.<br>Alvin, TX | Ethylene Production | Energy Efficiency<br>Low Carbon Fuels | Cracking heater to meet thermal efficiency of 92.6%<br>35% hydrogen in fuel to maintain a 0.71 carbon content in fuel | 2012 | PSD-TX-97769-GHG |
| Chevron Phillips, Olefins Unit<br>Cedar Bayou, TX | Ethylene Production | Energy Efficiency/ Good Design & Combustion Practices | GHG BACT for furnace limit flue gas exhaust temperature ≤ 350 °F.<br>365-day average, rolling daily | 2013 | PSD-TX-748-GHG |

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 furnaces at the Equistar La Porte facility have a projected energy efficiency, upon initial startup, around 93.4% which is higher than the efficiencies of the other furnaces provided in the table above. However, Equistar has requested that the BACT limit for the furnace take into account the affect of refractory and insulation degradation, and fouling of convection section tubes have on performance and efficiency over the life of the furnace. Equistar performed an efficiency calculation to simulate degradation by applying a fouling factor of 10 - 12% due to loss of heat transfer and assuming a stack temperature of 302 $^{o}$F. These factors were based on historical fouling impacts to furnaces within the company. Equistar calculated that over time, with degradation, the furnace efficiency could drop to 91%. Equistar will monitor the thermal efficiency and exhaust temperature as BACT.

The following specific BACT practices are proposed for the furnaces:

- *Energy Efficient Design* -A thermal efficiency of 91% will be maintained.
- *Low Carbon Fuels* – Using natural gas as the primary fuel, and fuel gas containing hydrocarbons and/or hydrogen as a supplemental fuel provides a reduction in combustion $CO_2$ when compared to diesel or coal.
- *Best Operation Practices* – The use of best operation 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 Compliance:

Equistar elects to demonstrate compliance with energy efficient operations by continuously monitoring the exhaust stack temperature of each furnace. The maximum stack exit temperature of 302 $^{o}$F on a 12-month rolling average basis will be calculated daily for each furnace. Thermal efficiency will be calculated monthly from these parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4th ed.) Annex G. Equistar La Porte conducted calculations to gauge the efficiency of the furnaces under degraded conditions. Equistar determined that when accounting for degradation they could not ensure a thermal efficiency greater than 91% over the life of the equipment. Therefore, they also elected to monitor the exhaust gas temperature and be able to maintain it to 302 $^{o}$F, which is a lower temperature than previously permitted for other similar furnaces. Efficient heater design, use of low carbon fuels, and good combustion practices of the furnaces corresponds to a permit limit of 281,766 tpy $CO_2$e for each furnace.

Equistar will design the cracking furnaces to be energy efficient by implementing the latest improvements and technologies in heat transfer and fluid flow to maximize the energy efficiency and energy recovery. Equistar will implement the following to ensure efficient operation of the cracking furnaces:

- Radiant section thermal efficiency - Vertical process tubes combined with floor mounted burners. Highly luminous radiant section, maximizing radiant heat transfer. Process tube placement to assure uniform heating, and to minimize shadowing.
- Sealed system - Minimize air infiltration with proper sealing of firebox penetrations.
- Reduce heat loss - Brick and ceramic fiber insulation to reduce heat loss.
- Energy recovery - Preheating of process fluids in the convection section. Use of integral quench exchangers and steam drum.
- Physical characteristics - Triangular pitch in convection section with corbels to control hot combustion gas flow and maximize transfer of heat into the process fluids. Properly sized and designed induced draft fan. Properly sized and placed stack.
- Burner design - Long, thin flames parallel to tubes with highly luminous flame envelopes. Minimum excess air design to enhance efficiency. Low-NOx burners.
- Careful control of feedstock/steam ratios, temperatures, pressures, and residence times to maximize production rate at normal firing rates.

Equistar will demonstrate compliance with the $CO_2$ emission limit for each furnace using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-2, 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:

$$CO2 = 44/12 * Fuel * CC * MW/MVC * 0.001 * 1.102311$$

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 Equistar may install, calibrate, and operate a $CO_2$ Continuous Emissions 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). Comparatively, the emissions from $CO_2$ contribute the most (greater than 99%) to the overall emissions from the furnaces and; therefore, additional analysis is not required for $CH_4$ and $N_2O$. 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 365-day average, rolling daily.

An initial stack test demonstration will be required for $CO_2$ emissions from the 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

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 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

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

**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

The only options, proper design and operation of the furnace, have 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 options 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

Equistar proposes to incorporate a combination of design and recommended operation to limit coke formation in the tubes to the extent practicable. No more than 20 decokes will occur per year per furnace. Managing coke buildup through such methods will result in limited $CO_2$ formation from annual decoking operations.

## XI. Flares (QE3050B and QE8050B)

$CO_2$ emissions from flaring process gas are produced from the combustion of carbon containing compounds (e.g., CO, VOCs, and CH4) present in the process gas streams and the pilot fuel. $CO_2$ emissions from the flare are based on the estimated flow rates of flared carbon-containing gases derived from heat and material balance data. The flares are examples of control devices in which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, the control of $CH_4$ in the process gas at the flare results in the creation of additional $CO_2$ emissions via the combustion reaction mechanism. However, given the relative GWPs of $CO_2$ and $CH_4$, it is appropriate to apply flare combustion controls to reduce $CH_4$ emissions since the impact of that GHG reduction will be greater than the GHG impact of the additional $CO_2$ emissions resulting from combustion, and there will also be concurrent destruction of VOCs and HAPs.

**Step 1** – Identification of Potential Control Technologies

- *Waste Gas Minimization* – Reducing the amount of waste gases combusted by the flare will effectively reduce $CO_2$ emissions.
- *Flare Gas Recovery* – Flaring can be reduced by installation of commercially available recovery systems, including recovery compressors and collection and storage tanks.
- *Good Flare Design* – Good flare design can be employed to destroy large fractions of the flare gas. Good flare design includes pilot flame monitoring, flow measurement, and monitoring/control of waste gas heating valve.
- *Natural Gas for Flare Pilots* – Natural gas is readily available and a low carbon fuel.

**Step 2** – Elimination of Technically Infeasible Alternatives

Only one option identified in Step 1, flare gas recovery, is considered technically infeasible.

Installing a flare gas recovery system to recover flare gas to the fuel gas system is considered feasible control technology for industrial flares. However the wide range of process gas compositions and flow volumes produced by the MSS activities associated with this project cannot be routed to the fuel gas system or to a process unit. For this project, flare gas recovery is eliminated as technically infeasible.

**Step 3** – Ranking of Remaining Technologies Based on Effectiveness

Use of a good flare design, waste gas minimization, and natural gas for the pilots with appropriate instrumentation and control are the remaining options. These remaining options cannot be ranked since their effectiveness cannot be quantified. All remaining options will be applied as GHG BACT for the flares in order to minimize emissions from the flares.

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

No significant adverse energy or environmental impacts associated with operating a flare to control process gas or using good flare design are expected.

**Step 5** – Selection of BACT

Natural gas-fired pilots, good flare design, and waste gas minimization will be applied as GHG BACT for the flares in order to minimize emissions from the flares. The flare will meet the requirements of 40 CFR §60.18, and will be properly instrumented and controlled. The flare shall be designed to achieve a minimum destruction and removal efficiency (DRE) of 99.5%.

These BACT practices result in a BACT limit of 6,121 tpy $CO_2e$ for EPN QE3050B and 33,025 tpy $CO_2e$ for EPN QE8050B.

## XII. Fugitive Emissions

GHGs emissions from leaking pipe components (fugitive emissions) in the proposed project contain $CH_4$.

**Step 1** – Identification of Potential Control Technologies

- *Installation of leakless/sealless technology components to eliminate fugitive emission sources.*
- *Implementing a leak detection and repair (LDAR) program in accordance with applicable state and federal regulations.*
- *Implement alternative monitoring using a remote sensing technology such as infrared camera monitoring.*
- *Implementing an auditory, visual, and olfactory (AVO) monitoring program.*
- *Design and construct facilities with high quality components, with materials of construction compatible with the process.*

**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.

*Instrument LDAR Programs* – LDAR programs have traditionally been developed for control of VOC emissions. Instrumented monitoring is considered technically feasible for components in $CH_4$ service.

*Remote Sensing* – Remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbon.

*AVO Monitoring* – Leaking components can be identified through AVO methods. AVO programs are common and in place industry and are considered technically feasible.

*High Quality Components* - A key element in control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. The olefins unit at Equistar's La Porte plant utilizes such components, and materials of construction, including gasketing that is compatible with the service in which they are employed.

**Step 3** – Ranking of Remaining Technologies Based on Effectiveness

- Leakless Technologies (~ 100%)
- Instrumented LDAR - 28LAER (97%)
- Remote Sensing (>75%)
- AVO (30%)
- High Quality Components

Leakless technologies are nearly 100% effective in eliminating leaks except when certain components of the technology suffer from a physical failure. These technologies do not, however, eliminate all leak interfaces, even when working perfectly. Those interfaces are typically stationary interfaces and therefore leak frequency at those interfaces of component parts would be expected to be low. The critical elements of leakless components include parts such as a bellows installed on a valve stem, or the diaphragm in a diaphragm valve. Following failure of one of these parts, the component is most often not repairable online and may leak until the next unit shutdown. This is the most effective of the controls.

LDAR programs based on quarterly testing with EPA Method 21 leak detection, and repair of leaks greater than 500 ppm have been given a 97% control credit by some state agencies. Such detection is possible for accessible components in combustible gas service, unless simultaneously emitted noncombustible gases such as nitrogen are in too high of a concentration. Instrumented monitoring can identify leaking $CH_4$, making identification of components requiring repair possible. This is the second most effective of the controls.

Remote sensing using an infrared imaging has proven effective for identification of leaks. Instrument LDAR programs and the alternative work practice of remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[15] Due to equivalency with Method 21 monitoring, it is assumed to have no less than 75% control effectiveness.

AVO methods of leak detection and repair are given credit for emission reduction, however the effectiveness is highly dependent on the system pressure (high pressure systems have a higher potential for making noise, or creating a visible emission or condensation/ice at the leak) and on the odor of the leaking material. Effectiveness is also dependent on the frequency of AVO inspection. This method cannot generally identify leaks at as low a leak rate as instrumented reading can identify.

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[15] 73 FR 78199-78219, December 22, 2008.

A key element in control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. The Olefins unit at Equistar's La Porte plant utilizes such materials of construction, including gasketing, that are determined to be compatible with the service in which they are employed. Use of high quality components is effective in preventing emissions of GHGs, relative to use of lower quality components.

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

Recognizing that leakless technologies have not been universally adopted as LAER or BACT, even for HAP service, it is reasonable to conclude that these technologies are impractical for control of GHG emissions which are not acutely toxic. In addition, there can be adverse environmental impacts from use of this technology, since following a failure of one of these parts, the component is most often not repairable online and may leak until the next unit shutdown, resulting in the emissions from the leak itself, and the emissions of GHG and other criteria pollutants that result from the need to shutdown and restart the facility. Based on these adverse environmental, leakless technologies are eliminated as BACT.

LDAR programs for which instrumented detection of leaks is an essential activity have traditionally been developed for control of VOC emissions. The adverse impact of non-VOC fugitive emissions of $CH_4$ due to global warming potential has not been quantified, and no reasonable cost effectiveness has been assigned. Equistar proposes to use TCEQ method 28LAER for LDAR.

Remote sensing of fugitive components in $CH_4$ service can provide an effective means to identify leaks. However, this option is rejected since the 28LAER program will be adopted for control of fugitive $CH_4$ emissions.

Design to incorporate high quality components is effective in proving longer term emissions control.

**Step 5** – Selection of BACT

Equistar proposes to use TCEQ method 28LAER for LDAR for fugitive emissions of methane for components that are in methane service. In addition to instrumented monitoring, Equistar will also use high quality components and conduct as-observed AVO monitoring. Equistar may conduct remote sensing for detection of leaks for pipes with fugitive emissions components that are in methane service.

## XIII. Endangered Species Act

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536(7)(a)(2)) 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.

EPA designated Equistar and its consultant, URS Corporation ("URS"), as non-federal representatives for purposes of informal consultation and preparation of a biological assessment (BA) for EPA's use in complying with the Act and EPA has reviewed a BA prepared by the applicant.

A BA has identified twelve (12) federally listed endangered or threatened species for Harris County, Texas:

| **Federally Listed Species for Harris County** by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS), and the Texas Parks and Wildlife Department (TPWD) | **Scientific Name** |
|---|---|
| **Plant** | |
| Texas Prairie Dawn Flower | *Hymenoxys texana* |
| **Birds** | |
| Red-cockaded Woodpecker | *Picoides borealis* |
| Whooping Crane | *Grus americana* |
| **Fish** | |
| Smalltooth Sawfish | *Pristis pectinata* |
| **Mammals** | |
| Louisiana Black Bear | *Ursus americanus luteolus* |
| Red Wolf | *Canis rufus* |
| **Amphibians** | |
| Houston Toad | *Bufo houstonensis* |
| **Reptiles** | |
| Green Sea Turtle | *Chelonia mydas* |
| Kemp's Ridley Sea Turtle | *Lepidochelys kempii* |
| Leatherback Sea Turtle | *Dermochelys coriacea* |
| Loggerhead Sea Turtle | *Caretta caretta* |
| Hawksbill Sea Turtle | *Eretmochelys imbricate* |

The BA identifies an action area, i.e., the area in which endangered or threatened organisms might be potentially affected by construction and operation of the proposed facility, including its emissions and wastewater discharges. EPA has adopted the data and analysis contained in the BA, and concludes that the permit action will have no effect on listed species or critical habitat.

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. Region 6 welcomes comments on the BA or concerns on the project's potential effect on listed species or their habitat.

## XIV. Magnuson-Stevens Act

Pursuant to Section 305(b)(2) of the Magnuson-Stevens Fishery Conservation and Management Act and implementing regulations at 50 C.F.R. 600.05 – 600.930, EPA is required to consult with NOAA's National Marine Fisheries Service on proposed actions that may adversely affect essential fish habitat (EFH). The project is adjacent to tidally influenced portions of the Upper San Jacinto Bay. These tidally influenced portions have been identified as potential habitats of postlarval, juvenile, subadult or adult red drum (*Sciaenops ocellatus*), white shrimp (*Penaeus setiferus*), brown shrimp (*Penaeus aztecus*), dog snapper (*Lutjanus jocu*), gray snapper (*Lutjanus griseus*), and lane snapper (*Lutjanus synagris*).

To assist EPA in evaluating the project's potential effects on those species and EFH, the applicant prepared an EFH assessment, which EPA has reviewed and adopted. The assessment's analysis, which is consistent with the analysis used in the BA discussed above, shows the project's construction and operation will have no adverse effect on EFH. The EFH Assessment is available at http://yosemite.epa.gov/r6/Apermit.nsf/AirP. Region 6 welcomes comments on the EFH Assessment or concerns on the project's potential effect on EFH or the commercial species at issue.

## XV. 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 URS, Equistar's consultant, submitted on December 4, 2012.

The Area of Potential Effect (APE) was determined to be approximately 34 acres of land within and adjacent to the construction footprint of the existing facility. URS performed an archaeological survey within the APE and a desktop review on the archaeological background and historical records within a 0.5-mile radius area of potential effect (APE) which included a review of the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP). No archaeological resources or historic structures were found within the APE. The entire APE is within a modern industrial facility that has been subject to many disturbances associated with previous construction activities, and that is located in an industrialized zone adjacent to other oil and gas refineries.

After considering the report submitted by the applicant, because no eligible properties are within the APE and the potential for archaeological resources is very low in the previously disturbed construction footprint itself, EPA's issuance of the permit to Equistar will not affect properties potentially eligible for listing on the National Register.

On December 12, 2012, 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 have historical interest 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 requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

## XVI. 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 GHG. 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.

## XVII. Conclusion and Proposed Action

Based on the information supplied by Equistar, 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 Equistar 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, rolling average, 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]** | | |
| QE1010B | QE1010B | Cracking Furnace | $CO_2$ | 281,506 | 281,766 | Furnace Gas Exhaust Temperature ≤ 302 °F. Maintain Thermal Efficiency of 91%. See permit condition III.A.1.n. through p. |
| | | | $CH_4$ | 5 | | |
| | | | $N_2O$ | 0.5 | | |
| QE1011B | QE1011B | Cracking Furnace | $CO_2$ | 281,506 | 281,766 | Furnace Gas Exhaust Temperature ≤ 302 °F. Maintain Thermal Efficiency of 91%. See permit condition III.A.1.n. through p. |
| | | | $CH_4$ | 5 | | |
| | | | $N_2O$ | 0.5 | | |
| QE3050B | QE3050B | ARU Flare | $CO_2$ | 6,037 | 6,121 | Good Combustion Practices. See permit condition III.A.2. |
| | | | $CH_4$ | 4 | | |
| | | | $N_2O$ | Negligible[3] | | |
| QE8050B | QE8050B | Elevated Flare | $CO_2$ | 32,563 | 33,025 | Good Combustion Practices. See permit condition III.A.2. |
| | | | $CH_4$ | 22 | | |
| | | | $N_2O$ | Negligible[3] | | |
| QE1416FB | QE1416FB | Decoking Drum | $CO_2$ | 1,047 | 1,047 | Good Combustion Practices. See permit condition III.A.1.q. and r. |
| QEFUG | QEFUG | Fugitive Process Emissions | $CH_4$ | Not Applicable | Not Applicable | Implementation of LDAR program. See permit condition III.A.3. |
| **Totals[4]** | | | **$CO_2$** | **602,659** | **$CO_2e$ 603,872** | |
| | | | **$CH_4$** | **43** | | |
| | | | **$N_2O$** | **0.5** | | |

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. All values indicated as negligible are less than 0.01 TPY with appropriate rounding.
4. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.