Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for Occidental Chemical Corporation, Ingleside Chemical Plant

Permit Number: PSD-TX-1292-GHG

June 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 May 18, 2012, Occidental Chemical Corporation (OxyChem), Ingleside Chemical Plant, submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for greenhouse gas (GHG) emissions from a proposed project. In connection with the same proposed project, OxyChem submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on April 27, 2012. The proposed project at the Ingleside Chemical Plant involves the construction of a new natural gas liquids (NGL) fractionation plant at the existing chemical plant. The new NGL fractionation plant will receive NGL by pipeline and will fractionate these liquids into commercial grade products (ethane, propane, butanes, and natural gasoline), which will be stored on-site (except for ethane). After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft PSD permit to authorize construction of air emission sources at the OxyChem, Ingleside Chemical Plant.

This SOB provides the information and analysis used to support EPA's decisions in drafting the PSD permit. It includes a description of the facility and proposed modification, the air permit requirements based on a BACT analyses conducted on the proposed new units, and the compliance terms of the permit.

EPA Region 6 concludes that OxyChem's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable PSD permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by OxyChem, and EPA's own technical analysis. EPA is making 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 GHG pollutants. See 75 FR 25178 (promulgating 40 CFR § 52.2305).

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

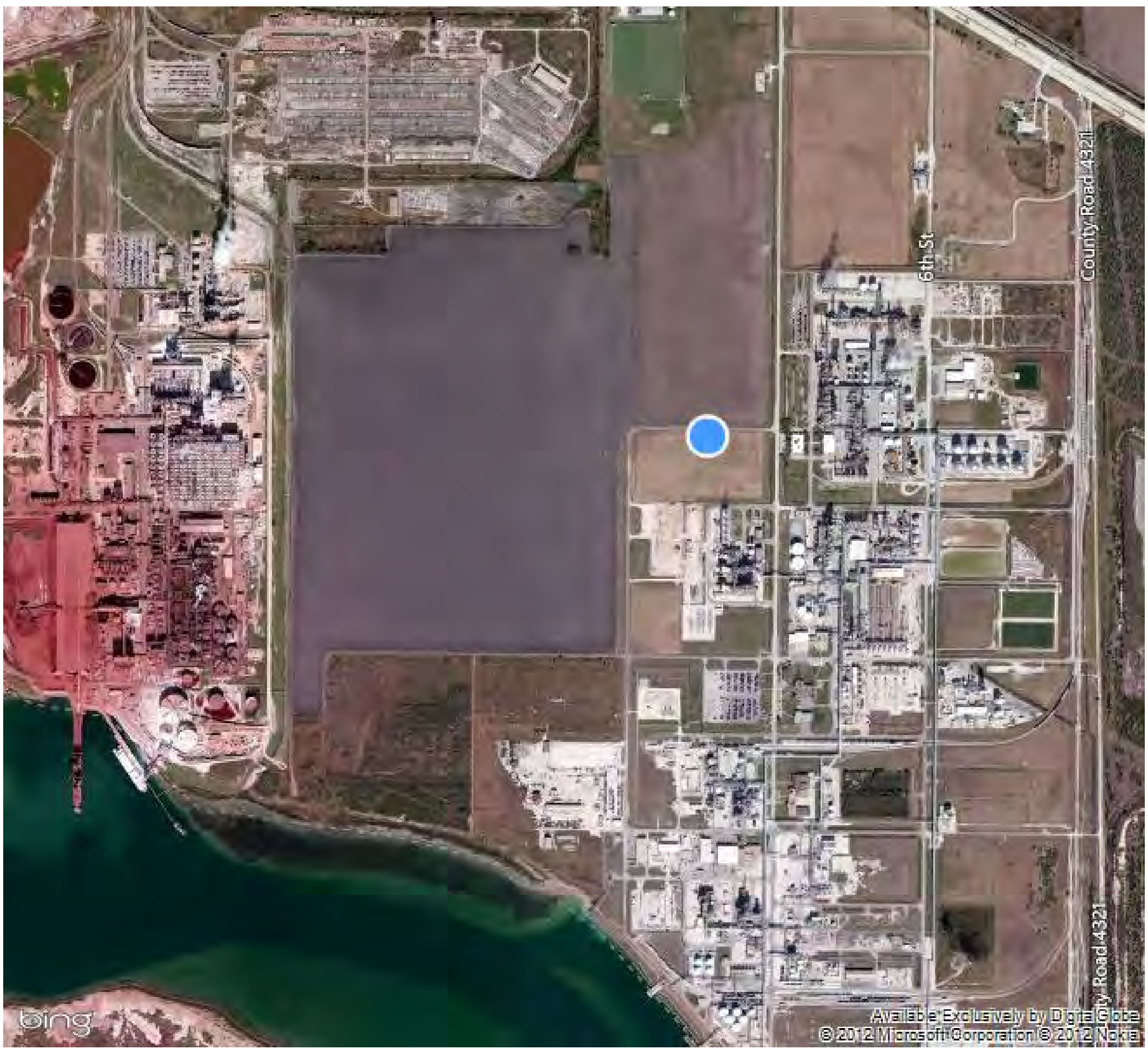
IV. Facility Location

The OxyChem, Ingleside Chemical Plant is located in San Patricio County, Texas, and this area is currently designated "attainment" for all NAAQS. The nearest Class 1 area is the Big Bend National Park, which is located over 100 miles from the site. The geographic coordinates for this facility are as follows:

Latitude: 27º 53' 12" North
Longitude: -97º 14' 7" West

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

Figure 1. Occidental Chemical Corporation, Ingleside Chemical Plant Location



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

EPA concludes that OxyChem's application is subject to PSD review for GHGs because the project would lead to an emissions increase of 75,000 tpy CO_2e or more as described at 40 CFR § 52.21(b)(49)(v)(*b)* and an emissions increase greater than zero tpy on a mass basis as described at 40 CFR § 52.21(b)(23)(ii) (Oxychem calculates CO_2e emissions of 83,641 tpy). EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

As the permitting authority for regulated NSR pollutants that trigger PSD (other than GHGs), TCEQ has determined that the proposed project is subject to PSD review for non-GHG pollutants. TCEQ has determined that the proposed project is subject to PSD for VOC, NO_2, CO, and PM_{10}/$PM_{2.5}$. At this time, TCEQ has not issued a PSD permit for the non-GHG pollutants.

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

EPA Region 6 applies the policies and practices reflected in the EPA document entitled *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011). Consistent with that guidance, we have neither required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the project has triggered review for regulated NSR pollutants that are non-GHG pollutants under the PSD permit sought from TCEQ. Therefore, air quality modeling or ambient monitoring may be required in order for TCEQ to issue a PSD permit for the non-GHG pollutants.

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow OxyChem to construct a new NGL fractionation plant at the existing Ingleside Chemical Plant located in Gregory, Texas. The NGL fractionation plant will receive NGL by pipeline and will fractionate these liquids into commercial grade products (ethane, propane, butanes, and natural gasoline), which will be stored on-site (except for ethane, which will be routed to the pipeline without storage), and then transferred to downstream markets by various means, including pipeline, tank trucks, rail cars, and barges. The new NGL fractionation plant will process approximately 87,000 barrels per day.

[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

Process facilities receive NGL by pipeline and separate these liquids by distillation into four products: ethane, propane, mixed butanes, and natural gasoline (higher molecular weight hydrocarbons in the NGL after ethane, propane and butanes are removed). Distillation concentrates sulfur compounds found in the NGL feed in the mixed butanes and natural gasoline fractions. A dedicated process unit converts these sulfur compounds to disulfide oil to be blended with the natural gasoline.

Each distillation process in the NGL fractionation facility operates under pressure. Each distillation process includes a fractionation column, a reboiler to provide heat for the distillation of liquids, and means to condense the vaporized fraction. The fractionation columns of the NGL fractionation facility use steam to supply heat to the process. Steam is supplied from both an adjacent existing natural gas fired cogeneration unit and from new steam generation facilities installed with the NGL plant. Reboilers are used on each fractionation column to exchange heat from steam with the process fluids. Steam from the thermal oxidizers and the existing cogeneration units provide heat to the reboiler which is a non-combusting unit. The reboiler is used to vaporize process fluids in the bottom of a fractionation column. Cooling and condensing for the fractionators is supplied from re-circulating propane refrigerant and re-circulating cooling water, both supplied from new facilities to be installed at the NGL fractionation project site.

Carbon dioxide and other acid gases present in the NGL feed are extracted by a re-circulating amine stream. Vent gases from regeneration of these amines are routed to a thermal oxidizer for destruction of organic compounds. Water and some aromatic hydrocarbons in the NGL feed are extracted by a re-circulating glycol stream. Vent gases from regeneration of glycol are also routed to a thermal oxidizer for destruction of organic compounds. Small amounts of liquid waste created in the re-circulating amine and glycol streams are removed by filters and are discarded as solid wastes along with the filter media.

Sulfur-containing organic compounds present in the NGL feed are concentrated by fractionation into the materials fed to the debutanizer. Sulfur compounds present in the overhead product (mixed butanes) and bottom product (natural gasoline) from the debutanizer are converted to disulfide oils that are blended with the natural gasoline. These conversion/extraction processes create vapor discharges that are routed to the thermal oxidizers and sulfide-rich aqueous caustic streams. These sulfide-rich caustic streams are treated to convert sulfides to disulfides and then regenerated to remove the disulfide oil after which the regenerated caustic stream is recycled to butane and gasoline sulfur removal units. A small stream of sulfide caustic will be periodically removed as a liquid waste stream, which will be disposed of off-site in accordance with applicable requirements.

Stored liquid products are transferred to markets by pipeline, by tanker truck, by rail car and by barge. Propane, butane, and natural gasoline products which do not meet specifications are stored temporarily on-site until they can be reprocessed. All non-pressurized storage tanks at the site handling VOC materials with a vapor pressure greater than 0.5 psia are vented to the thermal oxidizers for control. Also, non-pressurized loading vapors from barge, rail car, and truck loading will be controlled by the thermal oxidizers.

Process wastewater from NGL fractionators and product storage, transfer, and loading facilities is collected and transferred in closed systems to a wastewater storage tank. Collected wastewater is steam-stripped to remove organic compounds with the overhead vapor routed to the thermal oxidizer. The stripped wastewater is pumped to a biological treatment system at the existing plant. Vapors from process wastewater collection drain tanks, separator vents, and the spent caustic oxidizer vent are routed to the thermal oxidizers.

Fugitive emissions of GHG pollutants, including CO_2 and methane, may result from piping equipment leaks. The piping components that may leak include valves, flanges, pump seals, etc. OxyChem will implement the TCEQ 28MID Leak Detection and Repair (LDAR) program for the Ingleside Chemical Plant site.

The site has two existing cogeneration units (CG-1 and CG-2). The existing cogeneration units are not being modified. They are permitted by TCEQ under permit Nos. 35335 and PSD-TX-880. The cogeneration units will provide steam and energy to the new NGL fractionation facility. Currently, the excess energy produced by the cogeneration plants is sent to the grid. The cogeneration units will not have an increase in their currently permitted firing rates.

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit were conducted in accordance with EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines the steps for conducting a "top-down" BACT analysis. Those steps are listed below.

(1) Identify all available control options;

(2) Eliminate technically infeasible control options;

(3) Rank remaining control options;

(4) Evaluate the most effective controls (taking into account the energy, environmental, and economic impacts) and document the results; and

(5) Select BACT.

VIII. Applicable Emission Units

The majority of the GHGs associated with the proposed project are from combustion units (i.e., thermal oxidizers, flare, and emergency engines)[2]. Lesser amounts of GHG emissions are associated with a cooling tower and fugitive emissions from piping components. Stationary combustion units primarily emit CO_2 and small amounts of N_2O and CH_4. The following units are subject to this GHG PSD permit:[3]

- Thermal Oxidizers (EPNs: NGL-1 and NGL-2)
- NGL Emergency Flare (EPN: NGL-3)
- NGL Cooling Tower (EPN: NGL4)
- NGL Process Area Fugitives (EPN: NGL-5)
- NGL Emergency Generator Diesel Engine (EPN: NGL-10) and Firewater Pump Diesel Engines (EPNs: NGL-11, NGL-12, NGL-13, and NGL-14)

IX. BACT Analysis for Thermal Oxidizers (EPNs: NGL-1 and NGL-2)

Non-condensable vent streams from the NGL fractionation process and loading areas are generally combusted to destroy VOC before the inert gases are released to the atmosphere. This control can be accomplished by elevated flares, enclosed flares, or vapor combustors (thermal oxidizers). The destruction efficiency and the potential GHG control technologies will vary depending on the type of combustion device that is selected.

Because elevated flares and enclosed flares offer no opportunity for heat recovery and increased energy efficiency (i.e., minimizing GHG emissions by using waste heat to create steam, and thereby, lessening fuel firing in other steam generating sources), the primary control technologies for the destruction of waste gas streams focus on the use of thermal oxidizers.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Combustor Design* – Design achieves good fuel and air mixing with sufficient temperatures to assure complete combustion and to maximize thermal efficiency.
- *Heater Air/Fuel Control* – Monitoring of oxygen in the flue gas and firebox temperature for optimal efficiency.

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[2] GHG emissions from the thermal oxidizer include both the CO_2 produced from combustion of H_2S and VOC and the CO_2 contained in the waste gas that arrives from the amine regenerator.
[3] Cogeneration Units (EPNs CG-1 and CG-2) are existing units that are unmodified emission units for which a BACT analysis is not required. In addition, we note that the non-GHG emissions from the cogeneration units are addressed in the TCEQ permit and any additional emissions of hydrocarbons and CO to the cogeneration units is covered by the applicable requirements of the state permit.

- *Flame Monitoring and Periodic Tune*-up – Visual monitoring of flame patterns and periodically cleaning of burner and feed nozzles to assure complete combustion and efficiency. Also, includes periodic refractory repair and cleaning of waste heat recovery systems when required to maximize thermal efficiency.
- *Waste Heat Recovery* – Use of waste heat recovery from the thermal oxidizer exhaust to preheat the combustion air or produce steam for use at the site, thereby offsetting GHG emissions from other fuel combustion sources.
- *Process CO_2 Capture and Storage* – Capture, compression, transport, and geological storage or use of CO_2 rich vent streams rather than combustion.
- *Combustion CO_2 Capture and Storage* – Capture, compression, transport, and geological storage or use of CO_2 in the thermal oxidizer flue gas exhaust.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible for this project.[4]

Carbon Capture and Sequestration (CCS)

CCS is an available GHG control technology for "facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)."[5] CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable primarily to gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxyfuel combustion are not considered available control options for this proposed modification. However, the third approach, post-combustion capture, is available and applicable to thermal oxidizers.

[4] Based on the information provided by Occidental and reviewed by EPA for this BACT analysis, while there are some portions of CCS that may be technically infeasible for this project, EPA has determined that overall Carbon Capture and Storage (CCS) technology is technologically feasible at this source.
[5]U.S. Environmental Protection Agency, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf>.

Once CO_2 is captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR). 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.[6]

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Combustion CO_2 capture and storage (up to 90%) - can reduce GHG emissions by 83,000 tons/yr
- Waste heat recovery - can reduce GHG emissions by 17,000 tons/yr
- Process CO_2 capture and storage - can reduce GHG emissions by 6,500 tons/yr

Combustor design, heater air/fuel with temperature control, stack gas oxygen monitors and flame monitoring are considered good engineering practice and have been included with the proposed design. Evaluating their effectiveness and a subsequent evaluation of each technology is difficult to quantify, but they are the least effective.

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

<u>Carbon Capture and Sequestration (Combustion and Process)</u>

OxyChem provided a 5-step top-down BACT analysis addressing the technical infeasibility, economic costs and environmental impacts of utilizing carbon capture and sequestration (CCS) technology. OxyChem also provided a cost analysis to support its conclusion. As explained more fully below, EPA has reviewed OxyChem's CCS analysis and has determined that CCS is not economically feasible at this time for this application and also has negative environmental and energy impacts, which in combination support the elimination of CCS as BACT.

The capture, compression and sequestration of the CO_2 in the thermal oxidizer flue gas would reduce GHG emissions from the thermal oxidizers by 83,000 tons/year, but would require an additional 118 MMBtu/hr of thermal energy to strip the CO_2 from the solvent. This approach would require new natural gas-fired steam boilers that would create additional GHG emissions. It is estimated that the increased GHG emissions from the new steam generators would be 74,500 tons/year.

[6] 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

Consequently, the net overall reduction in GHG emissions would be 8,000 tons/year. The additional capital cost of the recovery and compression equipment and the pipeline is estimated to be about $300,000,000. There are also significant potential corrosion issues and material selection requirements associated with the sulfur dioxide in the flue gas that could further increase costs.

The capture, compression, and sequestration of the amine regenerator vent stream is estimated to cost about $300,000,000. The bulk of this cost would be for a pipeline to Hastings, Texas, approximately 180 miles away. The addition of CCS to the project would increase the total project capital cost by over 50% from $530,000,000 to $830,000,000 which is excessive in relation to the overall cost of the proposed project. Thus, CCS has been eliminated as BACT for the thermal oxidizers.

<u>Waste Heat Recovery</u>

The use of thermal oxidizers with waste heat recovery is estimated to require an additional investment of $5,000,000 and will save approximately $800,000 annually in fuel costs, while reducing GHG emissions by 17,000 tons per year. The investment cost is about $300 per annual ton of GHG. There are no adverse environmental impacts associated with this option. OxyChem selected this control technology as BACT for the proposed thermal oxidizers.

<u>Good Engineering Design and Work Practices</u>

Combustor design, heater air/fuel with temperature control, stack gas oxygen monitors and flame monitoring are considered good engineering practice and have been included with the proposed design.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the thermal oxidizer:

- *Combustor Design* – Design achieves good fuel and air mixing with sufficient temperatures to assure complete combustion and to maximize thermal efficiency.
- *Heater Air/Fuel Control* – Monitoring of oxygen in the flue gas and firebox temperature for optimal efficiency. The flue gas exhaust temperature will be monitored and recorded hourly and limited to less than 550^{o}F on a 365-day rolling average basis. The firebox temperature will be monitored and recorded hourly and shall exceed a temperature of 1,300 ^{o}F at all times.
- *Flame Monitoring and Periodic Tune*-up – Visual monitoring of flame patterns and periodically cleaning of burner and feed nozzles to assure complete combustion and

efficiency. Periodic refractory repair and cleaning of waste heat recovery systems when required to maximize thermal efficiency.

- *Waste Heat Recovery* – Use of waste heat recovery from the thermal oxidizer exhaust to preheat the combustion air or produce steam for use at the site, thereby offsetting GHG emissions from other fuel combustion sources.

Based on the identified control technologies and the project design, an emission limit for each thermal oxidizer of 41,578 tpy CO_2e was established. Compliance shall be determined by the monthly calculation of GHG emissions using equation W-3 consistent with 40 CFR Part 98, Subpart W [98.233(d)(2)].

X. NGL Emergency Flare (EPN: NGL-3)

The flare is used as a back-up device to the thermal oxidizers. It is used only during emergency periods when the thermal oxidizers are unavailable to process the vent gases from the fractionation unit, storage tanks, and loading areas. Under normal operation, the only GHG emissions associated with the flare are from the natural gas pilot burners. The flare will have minimum hydrocarbon destruction and removal efficiency (DRE) of 99% for methane.

Step 1 – Identification of Potential Control Technologies

- *Redundant Thermal Oxidizers* – The installation of redundant thermal oxidizers minimizes the probability of flaring due to an unexpected shutdown of a single thermal oxidizer.
- *Flare Gas Feed Controls* – The installation of flare gas feed meters and temperature monitors in the flare to minimize supplemental natural gas requirements when in operation.
- *Pilot Reliability and Sizing* – The use of energy efficient pilots to minimize natural gas consumption.
- *Pilot Flame Monitoring and Periodic Cleaning* – Monitoring of the pilots with temperature monitors and periodically cleaning the burner to assure proper combustion and efficiency.

<u>Redundant Thermal Oxidizers</u>

Thermal oxidizers require periodic maintenance for refractory repair, fan and motor bearing maintenance, burner inspection and repair, and waste heat boiler inspection and cleaning. Typically, at least two weeks per year are required for inspection and maintenance. By retaining the waste heat recovery with a second unit during this two week period and avoiding flaring, it is estimated that GHG emissions will be reduced by about 700 tons per year. This approach is considered the most effective control.

Pilot Reliability and Sizing

Modern high efficiency pilots can reduce natural gas consumption by about 30% over larger traditional pilots. This approach will reduce GHG emissions by about 100 tons per year. This option is considered the second most effective technology.

Pilot Flame Monitoring and Periodic Cleaning

Pilot Flame monitoring is considered good engineering practice and has been included with the proposed design.

Flare Gas Feed Controls

Flare gas feed controls are only effective when the flare is in service. Since this control will only occur during emergency circumstances, it is considered the least effective control technology for this specific system.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Since the combination of all of the control options in Step 1 are being proposed by the applicant, a ranking of the individual control options is not necessary.

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

Since the combination of all of the control options in Step 1 are being proposed by the applicant, there is no need to evaluate the economic, energy and environmental impacts of the proposed project.

Step 5 – Selection of BACT

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

- *Redundant Thermal Oxidizers* – The installation of redundant thermal oxidizers minimizes the probability of flaring due to an unexpected shutdown of a single thermal oxidizer.
- *Flare Gas Feed Controls* – The installation of flare gas feed meters and temperature monitors in the flare to minimize supplemental natural gas requirements when in operation. Feed flow

meters and temperature monitors inside the enclosed flare will provide rapid indication when the unit is operating. Natural gas will be added to assure adequate heating values for effective combustion.

- *Pilot Reliability and Sizing* – The use of high efficiency pilots to minimize natural gas consumption.
- *Pilot Flame Monitoring and Periodic Cleaning* – Monitoring of the pilots with temperature monitors and periodically cleaning the burner to assure proper combustion and efficiency. Each pilot will be monitored with a thermocouple. Both electronic and flame front generator systems will be provided for lighting the pilots.

Based on the identified control technologies and the project design, a BACT limit for the flare of 168 tpy CO_2e was established. Compliance with this limit will be determined by calculating GHG emissions on a monthly basis using the natural gas usage in the pilots. The flare is for emergency purposes and only the combustion of natural gas will be permitted.

XI. NGL Cooling Tower (EPN: NGL-4)

The cooling requirements for the NGL Fractionation Facilities are generally provided by evaporative cooling systems, but can also be provided by once through sea water cooling or air cooling. The make-up water can also be pretreated for removal of the bicarbonates.

Step 1 – Identification of Potential Control Technologies

- *Low Cycles of Concentration* – Operate the tower at sufficiently low cycles of concentration so as not to require any acid addition.
- *Acid and Blowdown Control* - Monitoring of circulating water pH and conductivity to control the acid addition and blowdown to control water chemistry.
- *Pretreatment of Make-up Water* – Use a reverse osmosis system to remove bicarbonates in the make-up water.
- *Once Through Seawater Cooling* – Use of once through seawater for process cooling rather than an evaporative cooling system.
- *Air Cooling* – Use of air coolers rather than an evaporative cooling water system for process cooling.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Once Through Seawater Cooling

The use of once through seawater cooling would eliminate the 209 tons per year of CO_2 emissions from the cooling tower with minimal increase in power or combustion related GHG emissions. This approach is considered the most effective control for GHG emissions.

Air Cooling

The use of air cooling would also eliminate the 209 tons per year of the CO_2 emissions from the cooling tower; however, it would significantly increase the power and thermal energy requirements for the NGL Fractionation Facilities. These greater power and energy requirements are due to higher operating temperature and pressure in the refrigeration and distillation column condensers. This approach would result in increased GHG emissions from the cogeneration facilities; however, this approach is considered the next most effective control for GHG emissions from the NGL cooling system.

Pretreatment of Make-up Water

Pretreatment of the make-up water in a reverse osmosis system could remove most of the bicarbonates from the cooling tower make-up and potentially eliminate the CO_2 emissions from the cooling tower. This pretreatment would result in increased GHG emissions from the cogeneration facilities for the additional power requirements for the reverse osmosis systems, which require high water pressure to operate effectively.

Low Cycles of Concentration

Operation of the cooling tower with a very high wastewater blowdown to reduce the bicarbonate concentration could reduce the CO_2 emissions by 80 - 90%. There is still some dissolved CO_2 in the make-up water that would be stripped out even if no acid were added. This approach is considered the next most effective control technology.

Acid and Blowdown Control

The effect on GHG emissions using pH and specific conductivity monitoring to control the acid injection and blowdown is difficult to assess, but it is considered the least effective means of control.

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

Once Through Seawater Cooling

The use of once through seawater cooling can be detrimental to fish and wildlife. Also, the use of seawater can lead to increased fouling of heat exchangers. Based on these impacts and the minimal reduction in GHG emissions, this technology is not chosen as a control option for GHG emissions from the cooling tower.

Air Cooling

The use of air cooling would eliminate the cooling tower GHG emissions, but increase emissions from the cogeneration facilities. It is difficult to assess, but air cooling for these facilities would generally be expected to increase energy consumption by 5 - 10%. This approach would represent 8,000 to 16,000 tons per year of increased GHG emissions from the cogeneration facilities. The increased emissions would be significantly more than the 209 tons per year that would be eliminated from the cooling tower. Therefore, air cooling is rejected on the basis of overall energy consumption and the overall increase in GHG emissions.

Pretreatment of Make-up Water

Pretreatment of the make-up water in a reverse osmosis system would require increasing the water pressure by several hundred psig. The additional power requirements would add about 2 MMBtu/hr of natural gas firing at the cogeneration facilities, increasing the GHG emissions by 1,024 tons per year. These GHG emissions more than off-sets the elimination of 209 tons per year of GHG emissions from the NGL Cooling Tower. Therefore, pretreatment of the make-up water by reverse osmosis is rejected due to the overall increase in GHG emissions.

Low Cycles of Concentration

The blowdown rate from the cooling tower would need to be increased from 100 gpm to at least 300 - 600 gpm to prevent scaling in the cooling water system without any acid addition. There is no other use for this water and it would have to be discharged as wastewater. This approach is considered extremely wasteful of fresh water, especially considering the minimal reduction in GHG emissions that would be realized, and therefore, this approach is rejected as BACT.

Acid and Blowdown Control

OxyChem has proposed to install and operate continuous pH and conductivity monitors on the cooling tower water primarily to control scaling and corrosion. This technology and operating practice will also result in some improved control of GHG emissions by maintaining consistent alkalinity in the cooling tower water.

Step 5 – Selection of BACT

The following specific work practices were determined to be BACT for the cooling tower:

Due to the negligible amount of fugitive GHG emissions from the cooling tower, none of the available control technologies are considered cost effective and BACT is determined to be no control. However, OxyChem will be required to install pH and conductivity analyzers on the cooling water supply to control acid addition and blowdown. Laboratory instruments will be used to periodically check the accuracy of these devices and provide information when the on-line analyzers are out of service for an extended period of time due to maintenance. This approach will minimize the GHG emissions associated with the cooling tower and satisfy GHG BACT requirements.

Using the operating practices above will result in an emission limit for the cooling tower of 209 tpy CO_2e. Compliance will be based on the monthly calculation of GHG emissions. OxyChem shall, on a monthly basis, test the cooling tower make-up water for alkalinity following Method 2320B from the *Standard Methods for the Examination of Water and Wastewater*. The bicarbonate value from this analysis will be used to calculate CO_2 emissions from the cooling tower using the following equations.

$$HCO_3\ loading\ \left(\frac{lb}{hr}\right) = Makeup\ Water\left(\frac{lb}{hr}\right) \times bicarbonate\ (ppm)$$

$$CO_2\left(\frac{lb}{hr}\right) = HCO_3\ \left(\frac{lb}{hr}\right) \times 44\ \times \left(\frac{1}{61}\right)$$

Where:
44 = Molecular Weight of CO_2
61 = Molecular Weight of HCO_3

$$CO_2\,TPM\ = CO_2\left(\frac{lb}{hr}\right) \times 2{,}000\frac{lb}{ton} \times xx\ hr/month$$

XII. NGL Process Area Fugitives (EPN: NGL-5)

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 7.94 tpy as CO_2e. Fugitive emissions of methane are negligible, and account for less than 0.01% of the project's total CO_2e emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Barrier sealing systems for pumps and compressors.*
- *Installing rupture discs beneath pressure relieving devices discharging to the atmosphere.*
- *Use of bellows sealed valves to eliminate valve stem packing leaks.*
- *Administration of a leak detection and repair (LDAR) program for fugitive emissions.*

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The use of barrier sealing systems for pumps and compressors, rupture discs for relief devices and bellows sealed valves address separate sources. Each technology is capable of 100% control for each source and each technology is considered the most effective control technology.

LDAR programs are typically used to control VOC emissions and can achieve up to 97% control of VOC emissions. Although not specifically designed for GHG emissions, they can be used to control GHG since GHGs are generally present in the same components that would be included in an LDAR program for VOC. It is assumed that the same control factors can be applied to GHG emissions. This approach is considered the least effective control technology.

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

Valves make up one of the largest sources of fugitive emissions and the use of bellows sealed valves can eliminate GHG emissions from the valve stems. These valves are generally only available on rising stem valves such as gate and globe valves. They are also commonly only available in the smaller sizes, and significantly more expensive. Consequently, their overall effectiveness is limited. The marginal additional level of control that is achieved over an LDAR program is minimal and not considered cost effective for VOC or GHG control.

The installation of rupture discs beneath relief valves, and barrier seals for pumps and compressors to control the negligible amount of GHG fugitive emissions that occur from these sources is considered cost prohibitive. However, if these controls are being implemented for VOC emissions control purposes, they will also result in effective control of the small amount of GHG emissions associated with these fugitive emission sources.

The use of an LDAR program to control a negligible amount of GHG emissions that occur as process fugitives is also considered cost prohibitive. However, if an LDAR program is being implemented for VOC emission control purposes, it will also result in an effective control of the small amount of GHG emissions associated with the same piping components.

The TCEQ's most stringent fugitive monitoring and maintenance program, 28MID with quarterly monitoring of flanges, is currently considered BACT for controlling fugitive VOC emissions at the existing site. As part of this 28MID approach all pumps and compressor seals in light liquid service are vented to control or are designed with non-leaker technology. OxyChem has proposed to implement 28MID to control VOC emissions from the new NGL Fractionation Facilities.

Step 5 – Selection of BACT

EPA has reviewed and concurs with OxyChem's NGL Process Ares Fugitives BACT analysis. Based on OxyChem's top-down BACT analysis for fugitive emissions, OxyChem concludes that using the TCEQ 28MID[7] leak detection and repair (LDAR) program constitutes BACT. OxyChem will, where technically feasible, install rupture discs beneath relief valves discharging to the atmosphere and will install barrier seal systems on pumps and compressors in VOC services as BACT for fugitives. EPA determines that the TCEQ 28MID work practice standard for fugitives for control of CH_4 emissions is BACT. As noted above, LDAR programs would not normally be considered for control of GHG emissions alone due to the negligible amount of GHG emissions from fugitives, and while the existing LDAR program is being imposed in this instance, the imposition of a numerical limit for control of those negligible emissions is not feasible.

XIII. NGL Emergency Generator Diesel Engine (EPN: NGL-10) and Firewater Pump Diesel Engines (EPNs: NGL-11, NGL-12, NGL-13, and NGL-14)

OxyChem has proposed to install one 1,200 HP emergency generator engine and four 500 HP firewater pump engines. The emergency engines proposed will operate at a low annual capacity factor - approximately one hour per week in non-emergency use. The engines are designed to use diesel fuel, stored in onsite tanks, so that emergency power is available for safe shutdown of the facility in the event of a power outage that may also include natural gas supply curtailments.

[7] The boilerplate special conditions for the TCEQ 28MID LDAR program can be found at http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bpc_rev28mid.pdf These conditions are included in the TCEQ issued NSR permit.

Step 1 – Identification of Potential Control Technologies

- *Low Carbon Fuels* – Use of fuels containing lower concentrations of carbon generate less CO_2, than other higher-carbon fuels. Typically, gaseous fuels such as natural gas or high-hydrogen plant tail gas contain less carbon, and thus lower CO_2 potential, than liquid or solid fuels such as diesel or coal.
- *Good Combustion Practices and Maintenance* - Good combustion practices include appropriate maintenance of equipment and operating within the recommended air to fuel ratio recommended by the manufacturer.

Step 2 – Elimination of Technically Infeasible Alternatives

- *Low Carbon Fuels* – Because the engines are intended for emergency use, these engines must be designed to use non-volatile fuel such as diesel. Use of volatile (low-carbon) natural gas in an emergency situation could exacerbate a potentially volatile environment that may be present under certain conditions, resulting in unsafe operation. Therefore, OxyChem proposes to use diesel fuel for the emergency engines, since non-volatile fuel must be used for emergency operations. The use of low-carbon fuel is considered technically infeasible for emergency generator operation and is not considered further for this analysis.
- *Good Combustion Practices and Maintenance* – Is considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

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

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

Step 5 – Selection of BACT

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

- *Good Combustion Practices and Maintenance* – Good combustion practices for compression ignition engines include appropriate maintenance of equipment, periodic testing conducted weekly, and operating within the recommended air to fuel ratio, as specified by its design. Oxychem will change the oil and filter, inspect all hoses and belts every 500 hours of operation or annually, whichever comes first. OxyChem will inspect the air cleaner every 1,000 hours of operation or annually, whichever comes first.

Using the operating practices identified above results in an emission limit of 100 tpy CO_2e. OxyChem will demonstrate compliance with the CO_2 emission limit using the emission factors for diesel fuel from 40 CFR Part 98 Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(2)(i) is as follows:

$$CO_2 = 1 \times 10^{-3} * Fuel * HHV * EF * 1.102311$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of diesel fuel (short tons)
Fuel = Annual volume of the liquid fuel combusted (gallons). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).
HHV = Annual average high heat value of the fuel (MMBtu per mass or volume). The average HHV shall be calculated according to the requirements of §98.33(a)(2)(ii).
EF = Fuel-specific default CO_2 emission factor, from Table C-1 of 40 CFR Part 98 Subpart C or the actual values from fuel analysis.
$1 \text{ X } 10^{-3}$ = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2.

XIV. Endangered Species Act (ESA)

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 adopted by EPA. Further, EPA designated Occidental Chemical ("OxyChem") and its consultant, Tetra Tech, as non-federal representatives for purposes of preparation of the BA.

A draft BA has identified twelve (16) species listed as federally endangered or threatened in San Patricio County, Texas:

Federally Listed Species for San Patricio 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	
Slender rush-pea	*Hoffmannseggia tenella*
South Texas ambrosia	*Ambrosia cheiranthifolia*
Birds	
Northern aplomado falcon	*Falco femoralis septentrionalis*
Whooping crane	*Grus americana*
Piping plover	*Charadrius melodus*
Fish	
Smalltooth sawfish	*Pristis pectinata*
Mammals	
Gulf Coast jaguarundi	*Herpailurus yagouaroundi cacomitli*
Red wolf	*Canis rufus*
Ocelot	*Leopardus pardalis*
West Indian manatee	*Trichechus manatus*
Mollusks	
Golden orb	*Quadrula aurea*
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*

EPA has determined that issuance of the proposed permit to OxyChem for construction of a new natural gas liquids fractionation plant at an existing facility will have no effect on four (4) of these listed species, specifically the the red wolf (*Canis rufus*), slender rush-pea (*Hoffmannseggia tenella*), South Texas ambrosia (*Ambrosia cheiranthifolia*), and the golden orb (*Quadrula aurea).* These species are either thought to be extirpated from the county or Texas or not present in the action area.

The remaining twelve (12) species identified are species that may be present in the action area in certain circumstances. As a result of this potential occurrence and based on the information provided in the draft BA, the issuance of the permit may affect, but is not likely to adversely affect the remaining species. As a result, EPA will submit the final draft BA to the Southwest Region, Corpus Christi, Texas Ecological Services Field Office of the USFWS for its concurrence that issuance of the permit may affect, but is not likely to adversely affect the following species:

- Gulf Coast jaguarundi (*Herpailurus yagouaroundi cacomitli*)
- Ocelot (*Leopardus pardalis*)
- Northern Aplomado falcon (*Falco femoralis septentrionalis*)
- Piping plover (*Charadrius melodus*)
- Whooping crane (*Grus americana*)

EPA will also submit the final draft BA to the NOAA Southeast Regional Office, Protected Resources Division of NMFS for its concurrence that issuance of the permit may affect, but is not likely to adversely affect the following species:

- leatherback sea turtle (*Dermochelys coriacea*)
- green sea turtle (*Chelonia mydas*)
- Kemp's ridley sea turtle (*Lepidochelys kempii*)
- loggerhead sea turtle (*Caretta caretta*)
- Hawksbill sea turtle (*Eretmochelys imbricate*)
- Smalltooth sawfish (*Pristis pectinata*)
- West Indian manatee (*Trichechus manatus*)

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

XV. Magnuson-Stevens Act

The 1996 Essential Fish Habitat (EFH) amendments to the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act) set forth a mandate for NOAA's National Marine Fisheries Service (NMFS), regional fishery management councils (FMC), and other federal agencies to identify and protect important marine and anadromous fish habitat.

To meet the requirements of the Magnuson-Stevens Act, EPA is relying on an EFH Assessment prepared by the Tetra Tech on behalf of OxyChem and reviewed and adopted by EPA.

The facility is adjacent to tidally influenced portions of the La Quinta Channel that adjoins to the Corpus Christi Ship Channel leading to the Gulf of Mexico. These tidally influenced portions have been identified as potential habitats of postlarval, juvenile, subadult or adult stages of red drum (*Sciaenops ocellatus*), shrimp (4 species), and reef fish (43 species). The EFH information was obtained from the NMFS's website (http://www.habitat.noaa.gov/protection/efh/efhmapper/index.html).

Furthermore, these tidally influenced areas have also been identified by NMFS to contain EFH for neonate of the finetooth shark (*Carcharhinus isodon*); juvenile of the blue marlin (*Makaira nigricans*); neonate and juvenile of the scalloped hammerhead shark (*Sphyrna lewini*), lemon shark (*Negaprion brevirostris*), and spinner shark (*Carcharhinus brevipinna*); and neonate, juvenile, and adult of the blacktip shark (*Carcharhinus limbatus*), bull shark (*Carcharhinus leucas*), sharpnose shark (*Rhizoprionodon terraenovae*), bonnet head shark (*Sphyrna tiburo*).

Based on the information provided in the EFH Assessment, EPA concludes that the proposed PSD permit allowing OxyChem construction of a new fractionation facility within the existing Ingleside facility will have no adverse impacts on listed marine and fish habitats. 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.

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

XVI. 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 and adopted cultural resource reports prepared by HRA Gray & Pape, LLC on behalf of Tetra Tech submitted on May 16, 2013.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 726 acres of land that includes 260 acres of the site facility that contains the construction footprint of the project and 466 acres of an approximately 18.5-mile long linear corridor that includes multiple pipelines associated with this project. HRA Gray & Pape, LLC prepared two separate cultural resource reports for each site. A field survey, including shovel testing, and a desktop review on the archaeological background and historical records within a 1.0-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) were done for each report.

Based on the desktop review for the site facility, four previous cultural surveys were made within a 1-mile radius of the APE. Nineteen historic or archaeological sites were identified from those reports, all of which are outside of the APE. Based on the results of the field survey, no archaeological resources or historic structures were found within the site facility. Based on the desktop review of the 18.5-mile linear corridor, at least seven previous cultural surveys were made within a 1-mile radius of the APE. Eleven historic or archaeological sites were identified from those reports, all of which are outside of the APE. Based on the results of the field survey of the pipeline corridor, thirteen archaeological resources or historic structures were found; however, none of these sites met the eligibility criteria for listing on the National Register and therefore was not recommended to be eligible for listing on the National Register.

EPA Region 6 determines that while there are cultural materials of historic or prehistoric age identified within the 1-mile radius of the site facility and the 18.5-mile long linear corridor, issuance of the permit to OxyChem will not affect properties on or potentially eligible for listing on the National Register. Additionally, no historic properties are located within the APE and that a potential for intact archaeological resources is low within the construction footprint of the project itself.

On April 24, 2013, 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 reports 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 these reports may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XVII. 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.

XVIII. Conclusion and Proposed Action

Based on the information supplied by OxyChem, our review of the analyses contained the TCEQ PSD 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 OxyChem 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 basis, shall not exceed the following:

Table 1. Facility Emission Limits[1]

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
NGL-1	NGL-1	Thermal Oxidizer	CO_2	41,450	41,577	Minimum firebox temperature of 1,400 ^oF Flue gas exhaust < 550^oF on a 365-day rolling average basis. See permit condition III.A.1.h. and i.
			CH_4	1.6		
			N_2O	0.3		
NGL-2	NGL-2	Thermal Oxidizer	CO_2	41,450	41,577	Minimum firebox temperature of 1,400 ^oF Flue gas exhaust < 550^oF on a 365-day rolling average basis. See permit condition III.A.1.h. and i.
			CH_4	1.6		
			N_2O	0.3		
NGL-3	NGL-3	NGL Emergency Flare	CO_2	1,000	1,000	Flare will meet the requirements of 40 CFR 60.18. See permit condition III.A.2.g.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
NGL-4	NGL-4	NGL Cooling Tower	CO_2	208	208	Monitor the feed water and make-up water. See permit condition III.A.3.b. through d.
NGL-5	NGL-5	NGL Process Area Fugitives	CO_2	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Implementation of LDAR Program. See permit condition III.A.4.c.
			CH_4	No Numerical Limit Established[5]		
NGL-10	NGL-10	Emergency Generator Engine	CO_2	34	34	Good combustion practices. See permit conditions III.A.5.b. and III.A.5.d - f.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
NGL-11 NGL-12 NGL-13 NGL-14	NGL-11 NGL-12 NGL-13 NGL-14	Firewater Pump Engines	CO_2	16[6]	64[6]	Good combustion practices. See permit conditions III.A.5.c. through f.
			CH_4	No Numerical Limit Established[4,6]		
			N_2O	No Numerical Limit Established[4,6]		
Totals[7]			**CO_2**	**84,206**	**CO_2e 84,468**	
			CH_4	**3.6**		
			N_2O	**0.6**		

1. Compliance with the annual emission limits (tons per year) is based on a 12-mponth rolling basis.
2. 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.
3. Global Warming Potentials (GWP): CH_4 = 21, N_2O = 310
4. All values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
5. Fugitive process emissions from EPN NGL-5 are estimated to be 0.43 TPY CO_2, 0.36 TPY of CH_4 and 8 TPY CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
6. The GHG mass basis TPY value is for each firewater pump engine. The CO_2e TPY limit is for all 4 combined.
7. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. These totals are given for informational purposes only and do not constitute emission limits.