Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the DCP Midstream, LP, Jefferson County NGL Fractionation Plant

Permit Number: PSD-TX-110557-GHG

August 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 July 10, 2012, the DCP Midstream LP (DCP) Jefferson County NGL Fractionation Plant, submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for a proposed construction project. On March 1, 2013, DCP submitted a revised application. In connection with the same proposed construction project, DCP submitted a permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on June 3, 2013. The project proposes to construct two new natural gas liquids (NGL) fractionation trains to separate a NGL feed into separate ethane, propane, butane, isobutene, and gasoline fractions. DCP also proposes to construct a deisobutanizer (DIB) column, for each train, to separate isobutane and normal butane from the mixed butane stream. 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 DCP, Jefferson County NGL Fractionation Plant.

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

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

II. Applicant

DCP Midstream, LP
370 17th Street, Suite 2500
Denver, CO 80202

Facility Physical Address:
Hillebrandt Rd – 3.2 miles North of the Steinhagen Road (Humble Camp Road) intersection, or 2.8 miles West and South of the intersection of Hillebrandt Road and W Port Arthur Rd (TX-93 Spur).
Beaumont, TX 77707

Facility Mailing Address:
662 S. Shelby
Carthage, TX 75633

Contact:
Lynn C. Holt
Senior Environmental Specialist
DCP Midstream, LP
(903) 694-4114

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). The State of 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

IV. Facility Location

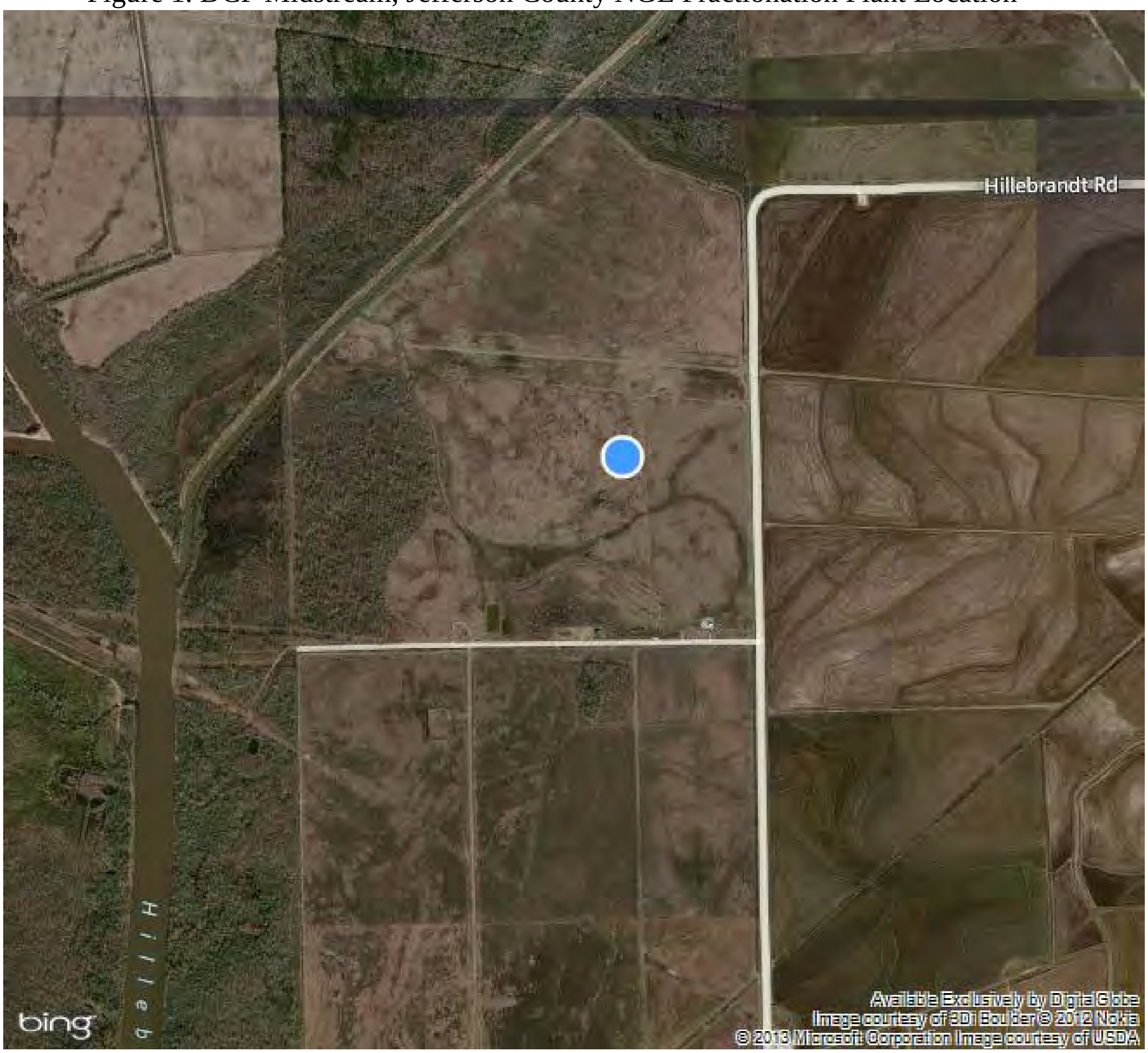
The DCP, Jefferson County NGL Fractionation Plant is located in Jefferson County, Texas. The geographic coordinates for this facility are as follows:

Latitude: 29º 59' 27.7" North
Longitude: -94º 6'44.6" West

Jefferson County is currently designated attainment for all criteria pollutants. The nearest Class I area, at a distance of more than 500 kilometers, is Breton National Wildlife Refuge.

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

Figure 1. DCP Midstream, Jefferson County NGL Fractionation Plant Location



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

EPA concludes DCP's application is subject to PSD review for the pollutant GHGs, because the project will constitute a new stationary source that will emit or have the potential to emit 100,000 tpy CO_2e as described at 40 CFR § 52.21(b)(49)(v)(*a)* and greater than 100/250 tpy on a mass basis (DCP calculates CO_2e emissions of 210,691 tpy). As noted above in Section III, EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR section 52.21 (except paragraph (a)(1)). *See,* 40 CFR § 52.2305.

The applicant represents that the proposed project is not a major stationary source for non-GHG pollutants. The applicant also represents that the increases in non-GHG pollutants will not equal or exceed the significant emissions rates at 40 CFR 52.21(b)(23). At this time, TCEQ, as the permitting authority for regulated NSR pollutants other than GHGs has not issued the permit for non-GHG pollutants. Emission limits below the rates identified in (b)(23) must be in place prior to construction to ensure the validity of this applicability analysis and the source's authorization to construct a source of GHG emissions.

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 of 40 CFR 52.21 (o) and (p), respectively. Instead, EPA has determined that compliance with the selected BACT is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules, with respect to emissions of GHGs. The applicant has, however, submitted an analysis to evaluate the additional impacts of the non-GHG pollutants, as it may otherwise apply to the proposed project.

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow DCP to construct two NGL fractionation trains to separate a Y-grade NGL feed into liquid products (ethane, propane, normal butane, isobutane, and natural gasoline). The facility will be designed with a nominal capacity of 75,000 barrels per day (bpd) per train and includes amine treating, natural gasoline treating, molecular sieve dehydration, hot oil as the primary heat source, refrigerant propylene and wet surface air coolers/condensers (WSAC) for cooling and condensation, two thermal oxidizers (TO) for control of waste gas streams, and a flare. The throughput of an individual train may exceed 75,000 bpd and is dependent on the inlet NGL composition without exceeding the CO_2e emissions estimated in the GHG PSD permit application. Compression for the propylene refrigeration and process heat pumps will be accomplished using compressors powered by electric motors. The system used to dehydrate the inlet feedstock will use one regeneration heater per train to regenerate the molecular sieve dehydrator beds. The hot oil for the process is heated using a natural gas-fired heater for each train. Heat exchangers will be incorporated throughout the process to take advantage of heating and cooling efficiencies. The GHG emissions will be generated by the two hot oil heaters, two regeneration heaters, two thermal oxidizers, emergency generator engine, emergency firewater pump engine, and the flare. All other new units at the facility are either a closed system, have only fugitive emissions, or vent to the flare.

The first stage in each fractionation train is an Amine Treating Unit. This unit will use amine contactors to remove CO_2 and H_2S impurities from the NGL stream. Some hydrocarbons will also be absorbed in the process. Specifically, the rich amine will be routed to an amine regenerator, where heat from the fractionation process' hot oil system will enable the volatilization of the CO_2, H_2S, and hydrocarbons (primarily VOC) from the rich amine stream. The resulting lean amine will be returned to the amine contactors for reuse. The Amine Treating Unit will be a closed loop system. Waste gas from the amine regenerator, which is composed of CO_2, H_2S, and VOC, will be routed to the thermal oxidizer (TO) for combustion of H_2S and VOC, and the combustion will generate SO_2 and additional CO_2 emissions. The TO will be designed to combust low-VOC concentration gas and will have a fuel rating of 5 MMBtu/hr, which will keep the temperature in the combustion chamber at or above the temperature required to maintain a 99.9% destruction efficiency. The combustion chamber temperature required to maintain a 99.9% destruction efficiency will be based on performance testing as outlined in the permit. The TO will generate combustion-related GHG emissions.

From the Amine Unit, the NGL will be routed through a Molecular Sieve dehydration unit, where the water content of the NGL will be reduced. A regeneration heater will vaporize a small slip stream of the NGL downstream of the mole sieve dehydrators to a gas which is routed back through the mole sieve beds to regenerate the beds. The wet gas will then be condensed to wet NGL and routed back into the system inlet. There are two sieve beds in the molecular sieve design, and one bed will be regenerated at a time. The Molecular Sieve unit will not have vents to the atmosphere. The only GHG emissions from the Molecular Sieve will be fugitive piping or equipment leaks. From the Molecular Sieve dehydration unit, the NGL will be fed to a series of trayed columns (deethanizer, depropanizer, debutanizer, and deisobutanizer) for separation into constituent product liquids. No GHG emissions will be generated from the product columns, because the processes will be closed system and most, if not all, CO_2 is removed at the Amine Unit. Additionally, very little, if any, methane is contained in the NGL that will enter the plant.

A natural gasoline stream from the debutanizer reboiler is sent to the natural gasoline air cooler (fin fan cooler) and then to the reflux cooler wet surface air cooler (WSAC) to be further cooled. The natural gasoline stream from the reflux cooler WSAC is routed to the Natural Gasoline Treating section. The natural gasoline is treated to convert trace amounts of thiophenes and mercaptans into disulfides. After leaving the natural gasoline treater, the natural gasoline product is filtered to remove any fines (particulate matter) and then sent through the metering section of the plant and out to the natural gasoline pipeline.

The hot oil system is a closed loop system that supplies hot oil to various heat exchangers. The hot oil surge drum is a nitrogen-blanketed vessel that collects all the hot oil returns. The hot oil heater is natural gas fired. Heat exchangers for the deethanizer reboiler, depropanizer reboiler, debutanizer reboiler, amine regenerator reboiler, and the caustic/hydrocarbon separator heating coil all utilize hot oil as the heat source.

The Flare System collects process and waste gases from relief valve discharges, other emergency vents, intermittent vents, and maintenance, startup, and shutdown (MSS) vents. Vapor is sent to the flare knockout (KO) KO drum and liquids are separated and pumped from the flare KO drum to the process waste water flash drum (which vents to the flare). During normal operations, there is no other flow to the process wastewater flash drum. The flare is equipped with natural gas-fired continuous pilots, several continuous natural gas purges on the flare header, and a flare stack blower ensuring a smokeless design. The presence of pilot flames shall be continuously monitored by a thermocouple or the equivalent.

Each train will be equipped with a thermal oxidizer (TO) that includes a gas-fired burner rated at 5 MMBtu/hr that will be used to combust three waste gas streams from the process during normal operations. The first waste gas stream consists of flash gas from the rich amine flash drum and acid gas from the amine regeneration system. This stream is compromised of primarily CO_2 with some sulfur compounds and VOCs. The second stream is the vent from the natural gasoline treater flash pot containing small amounts of various mercaptans, sulfur compounds, and hydrocarbons. The third stream is composed of various seal gas vents from compressors within the process which contain various hydrocarbons. The TO will operate with a destruction efficiency of 99.9% for VOC and sulfur compounds. The combustion chamber will maintain a sufficient temperature (actual temperature to be based on source testing) and a residence time of 0.5 seconds or greater to ensure 99.9% destruction efficiency.

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 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.

VIII. Applicable Emission Units and BACT Discussion

The majority of the contribution of GHGs associated with the project is from emissions at combustion sources (i.e., hot oil heaters, regeneration heaters, engines, thermal oxidizers, and flare). The site has fugitive emissions from piping components which contribute a small amount of GHGs. The combustion units primarily emit carbon dioxide (CO_2), and small amounts of nitrous oxide (N_2O) and methane (CH_4). The following devices are subject to this GHG PSD permit:

- Hot Oil Heaters (EPNs: HOH1 and HOH2)
- Regeneration Heaters (EPNs: HTR1 and HTR2)
- Flare (EPN: FLR1)
- Thermal Oxidizers (EPNs: TO1 and TO2)
- Emergency Firewater Pump Engine (EPN: ENG1)
- Emergency Generator Engine (EPN: ENG2)
- Trace Erase Systems (EPNs: TE1 and TE2)
- Fugitives (EPNs: FUG1 and FUG2)

IX. Plant-wide GHG Controls

DCP performed a BACT analysis on GHG control technologies that could be implemented on a plant-wide basis. The BACT analysis for plant-wide GHG emission reductions focuses on two categories: energy efficiency measures and carbon capture and sequestration (CCS).

<u>Energy Efficiency Consideration</u>

The proposed plant is being designed with heat and process integration for increased energy efficiency. Where feasible, the plant utilizes available process streams to transfer heat or cooling which reduces combustion heating and refrigeration requirements in the process. Process-to-process heat exchangers will be used to transfer energy between process streams to reduce heat duty requirements. Shell and heat tube exchangers will be utilized to cool process streams where appropriate, which reduces the refrigeration needed.

DCP proposes to insulate equipment (vessels), piping, and components in both hot and cold service. This will prevent heat losses to the atmosphere from equipment containing hot streams or excessive warming of equipment containing cold streams. This will minimize the need for additional heat input and refrigeration needed.

Process control instrumentation and pneumatic components will be operated using compressed air rather than fuel gas or off-gas; therefore no GHG emissions will be emitted to the atmosphere from these components.

The proposed plant will be built using new, state-of-the-art equipment and process instrumentation and controls. DCP's operating and maintenance policies will maintain all equipment according to manufacturer specifications in order to keep all equipment operating efficiently.

<u>Carbon, Capture, and Sequestration (CCS)</u>

Four main components of CCS were evaluated:

- Capture of CO_2 from sources including combustion exhaust streams and amine regenerator vent vapors;
- Clean-up of emission streams to remove impurities (potentially sulfur and water) to meet pipeline specifications and compress the CO_2 to pipeline conditions;
- Transport of compressed CO_2 to a sequestration site; and
- Sequestration of CO_2.

Capture of Waste Streams

The potential CO_2 eligible for CCS application would include emissions from the amine vents prior to combustion in the thermal oxidizers, the heater exhaust (hot oil and regeneration heaters), and the Trace Erase Systems. These CO_2 emissions total 190,957 TPY. Assuming a 90% capture efficiency of CO_2, CCS could decrease CO_2 emissions by 171,861 TPY.

Cleanup of Waste Streams

In order to remove CO_2 from the heater exhaust streams, remove impurities, and compress the CO_2 stream to pipeline pressure and temperature, additional equipment would be needed. At a minimum DCP would need to install electric or gas-fired motors for compression, heat exchangers to cool the exhaust streams from the combustion sources, additional amine treating units for purification of the CO_2 stream, and additional separation equipment including scrubbers and mole sieves. The additional equipment needed to purify and compress the CO_2 stream would have an estimated capital cost of $82,377,400. The annualized costs associated with the new equipment are estimated using US EPA's Air Pollution Control Cost Manual, Sixth Edition[1]. The total annualized cost of the CO_2 capture and cleanup equipment is estimated to be $24,606,860.

[1] This document can be found at http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf

Additional treating and purification units would also increase energy consumption and heat requirements. This would result in emissions of GHG and criteria pollutants due to larger and/or additional natural gas-fired heaters needed to provide heat for the treating and purification units. Installation of additional heaters and gas-fired compression would result in emissions of one or more criteria pollutants exceeding the PSD significant emissions threshold. The additional heater and compression equipment required to capture, purify, and compress the fired heater exhaust gases alone would result in a CO_2 emissions increase of approximately 140,000 tpy. Additional heat exchangers would result in negative environmental impacts, because additional or larger wet surface air condensers would be required to the site to provide cooling water to the heat exchangers resulting in additional particulate matter emissions from the wet surface air coolers. Therefore, the implementation of CCS would result in at most a 19% CO_2 emission reduction compared to the CO_2 emissions from the facility without CCS.

Transport

DCP has determined that the nearest facility capable of accepting an anthropogenic CO_2 stream is the Denbury Green Pipeline, approximately 1.5 miles from the Jefferson County NGL Fractionation Plant. The capital cost of constructing a pipeline from the DCP plant to the Denbury pipeline is estimated using the National Energy Technology Laboratory's document "Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs"[2]. The pipeline is estimated to cost approximately $2,627,597.

The annual operating costs of the pipeline are estimated to be approximately $12,948. In addition, the capital recovery cost is estimated to be approximately $427,641. Therefore, the total annualized cost of the pipeline would be approximately $440,589 per year.

Sequestration

Obtaining an estimate of the cost to utilize the Denbury Green Pipeline would require DCP to enter into a contract with Denbury. DCP does not wish to enter into a formal business agreement with Denbury; therefore, DCP has conservatively assumed that utilizing the Denbury Green Pipeline to have a cost of $0 per ton of CO_2 sequestered for determining the total cost of CCS.

The total capital cost of implementing CCS is estimated to be $85,004,997. The total annualized cost of implementing CCS is estimated to be $25,047,449 per year. The capital cost of the Jefferson County NGL Fractionation Plant is estimated at $500,000,000. Based on a 7% interest rate, and a 20-year equipment life, the annualized capital cost is estimated to be $47,196,465 per year. Implementing CCS would increase the total capital cost of the proposed project by at least

[2] This document can be found at http://www.netl.doe.gov/energy-analyses/pubs/QGESStransport.pdf

17%, and increase the annual cost of the project by approximately 53%. EPA has reviewed DCP's CCS analysis and has determined that CCS is not economically feasible at this time for this application, and has eliminated CCS as a potential BACT option.

In addition to maintaining that CCS would be economically infeasible for this project, DCP also asserts that CCS can also be eliminated as BACT based on the environmental impacts from a collateral increase of National Ambient Air Quality Standards (NAAQS) pollutants. According to the applicant, implementation of CCS would increase emissions of NO_x, CO, VOC, PM_{10}, and SO_2 from the additional utilities and energy demands that would be required to operate the CCS system. The increase in these criteria pollutants, according to the applicant, would be greater if looking at the emissions from the other support equipment that would be needed to further treat and compress the CO_2 emissions.

EPA notes that where GHG control strategies affect emissions of other regulated pollutants, trade-offs in selecting GHG pollution controls can be legitimately taken into account. See PSD Permitting Guidance at pp. 40-42. Here, the plant is located in Jefferson County, which is part of the former Beaumont-Port Arthur ozone non-attainment area. This area is currently in maintenance for ozone; therefore the generation of additional NOx and VOC could exacerbate ozone formation in the area. Many of the devices whose carbon emissions have triggered PSD permitting for GHGs (the thermal oxidizers and flare, for example) are pollution control measures to control emissions of ozone precursors. Thus, there is special sensitivity about employing control measures that would result in emission increases of ozone precursors. EPA reviewed DCP's cost analysis and the estimated pollutant increases that would result from the implementation of CCS, and concludes that CCS can be eliminated as BACT for this project due to the cost increase to the project. It is not necessary, therefore, to also reject CCS based on the projected collateral emission increases of ozone precursors in an ozone non-attainment area, but EPA notes that the applicant's concerns are legitimate factors for consideration.

X. Hot Oil Heaters (EPNs: HOH1 and HOH2)

Each fractionation train has a hot oil heater (HOH1 and HOH2). The hot oil heaters provide hot oil used in four column reboilers (deethanizer bottom reboiler, depropanizer bottom reboiler, debutanizer reboiler, and amine regenerator reboiler) that are shell and tube heat exchanges. Hot oil is also routed through a heating tube bundle in the caustic/hydrocarbon separator vessel to heat the spent caustic solution to aid in the separation of any dissolved or entrained hydrocarbons. The natural gasoline treating water heater has a shell and tube heat exchanger through which hot oil is routed. Hot oil is routed through a heating coil in the process waste water flash drum to heat the process waste water to aid in separation and vaporization of any hydrocarbons that may be dissolved or entrained in the waste water prior to sending it to the waste water storage tank. Each hot oil heater has a maximum rated capacity of 179 MMBtu/hr.

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.
- *Use of Efficient Process Controls, Good Combustion Practices, and Scheduled Maintenance* – Use of these measures would ensure the heaters are operating as efficiently as possible.
- *Selection of Low Carbon Fuels* – Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input.

Step 2 – Elimination of Technically Infeasible Alternatives

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

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- CCS
- Use of Low Carbon Fuels (up to 100% for fuels containing no carbon),
- Use of Efficient Process Controls, Good Combustion Practices, and Scheduled Maintenance

Virtually all GHG emissions from fuel combustion result from the conversion of carbon in the fuel to CO_2. Natural gas is the lowest carbon fuel available for use in the proposed heaters.

Use of efficient process controls, good combustion practices, and scheduled maintenance are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only.

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

<u>Carbon Capture and Storage</u>

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

Use of Low Carbon (Natural Gas) Fuel

Natural gas is the lowest carbon fuel available for use in the proposed heaters. Natural gas is a very clean burning fuel with respect to criteria pollutants and thus has minimal environmental impact compared to other fuels.

Process Controls, Good Combustion Practices, and Maintenance

The use of efficient process controls, good combustion practices, and scheduled maintenance will ensure the hot oil heaters are operating as efficiently as possible. Furthermore, proper operation of the hot oil heaters will extend their useful life and has no negative environmental or energy impacts.

Step 5 – Selection of BACT

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

Company / Location	Process Description	BACT Control(s)	BACT Emission Limit / Requirements	Year Issued	Reference
Energy Transfer Company (ETC), Jackson County Gas Plant Ganado, TX	4 Hot Oil Heaters (48.5 MMBtu/hr each) 4 Trim Heaters (17.4 MMBtu/hr each) 4 Molecular Sieve Heaters (9.7 MMBtu/each) 4 Regenerator Heaters (3 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit for process heaters per plant (one of each heater per plant) of 1,102.5 lbs CO_2/MMSCF 365-day average, rolling daily for each plant	2012	PSD-TX-1264-GHG
Enterprise Products Operating LLC, Eagleford Fractionation Mont Belvieu, TX	NGL Fractionation 2 Hot Oil Heaters (140 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters have a minimum thermal efficiency of 85% on a 12-month rolling basis.	2012	PSD-TX-154-GHG
Energy Transfer Partners, LP, Lone Star NGL Mont Belvieu, TX	2 Hot Oil Heaters (270 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters - 2,759 lb CO_2/bbl of NGL processed. 365-day average,	2012	PSD-TX-93813-GHG

			rolling daily		
Copano Processing L.P., Houston Central Gas Plant Sheridan, TX	2 Supplemental Heaters (25 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices, and Limited Operation	Each heater will be limited to 600 hours of operation on a 12-month rolling basis.	2013	PSD-TX-104949-GHG
KM Liquids Terminals, Galena Park Terminal Galena Park, TX	2 Hot Oil Heaters (247 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters have a minimum thermal efficiency of 85% on a 12-month rolling basis.	2013	PSD-TX-101199-GHG

The Enterprise Eagleford Fractionation and Energy Transfer Partners Lone Star NGL are both natural gas liquids (NGL) fractionation facilities. The Lone Star NGL facility produces a higher grade of propane for export purposes that requires a higher heat duty than the Enterprise facility. DCP has proposed to monitor thermal efficiency of the hot oil heaters. They have proposed to maintain an 85% thermal efficiency which is equal to the thermal efficiency that was proposed by Enterprise Products Operating and KM Liquids Terminals for their hot oil heaters. The Enterprise heaters are rated at 140 MMBtu/hr and the KMLT heaters are rated at 247 MMBtu/hr. The hot oil heaters proposed by DCP are rated at 179 MMBtu/hr, making them similar in size to the hot oil heaters proposed by Enterprise. We analyzed the proposed BACT and have determined it is consistent with other BACT determinations for similar units.

The following specific BACT practices are proposed for the heaters:

- *Use of Efficient Process Controls, Good Combustion Practices, and Scheduled Maintenance* – The proposed plant design includes specifications for state-of-the-art process instrumentation and controls. Process instrumentation and controls for the hot oil heaters include fuel gas monitoring for consumption and temperature monitoring of the hot oil to insure the heaters fire sufficiently to maintain the appropriate oil temperature for heat requirements. DCP will follow the recommended maintenance schedule from the hot oil heater manufacturer.
- *Selection of Low Carbon Fuels* – Pipeline quality natural gas will be the only fuel fired in the proposed heaters. It is the lowest carbon fuel available for use at the Jefferson County NGL Fractionation Plant.

The following monitoring and work practice requirements proposed by DCP will assist in maintaining the BACT efficiency limit and annual emission limits for the hot oil heaters:

- Use of natural gas as fuel.
- Installation of insulation where feasible on heater surfaces.

- Perform annual maintenance as recommended by the manufacturer and maintain records of maintenance activities.
- Clean heater burner tips and convection tubes at a minimum of every 5 years.
- Install a totalizing fuel flow meter (calibrated annually) to continuously monitor fuel usage and record daily fuel consumption.
- Install a non-resettable hour meter to continuously record hours of operation.
- Semiannual analysis of plant natural gas fuel to determine the higher heating value in Btu/scf, molecular weight, and carbon content, or certification from natural gas fuel supplier containing the same information.
- Install and operate combustion air controls to limit excess air.
- Install and operate an oxygen analyzer to allow manual adjustment to optimize fuel/air mixture and limit excess air.
- The oxygen analyzer will continuously monitor and record oxygen concentrations with an averaging period of 15 minutes and maximum limit of 15% O_2.

BACT Limits and Compliance:

DCP shall demonstrate compliance with an 85% thermal efficiency on each of the hot oil heaters, which corresponds to an annual emission limit of 78,500 tpy CO_2e for each hot oil heater. The annual emission limit includes MSS emissions. The hot oil heaters will be continuously monitored for exhaust temperature, fuel temperature, ambient temperature, and excess oxygen. Thermal efficiency will be calculated for each operating hour from these parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4^{th} ed.) Annex G, reduced to a monthly average, and maintain a minimum overall thermal efficiency of 85% on a 12-month rolling average basis.

The hot oil heaters will be designed to incorporate efficiency features, including insulation to minimize heat loss and heat transfer components that maximize heat recovery while minimizing fuel use. DCP will maintain records of heater tune-ups, burner tip maintenance, O_2 analyzer calibrations and maintenance for all heaters. In addition, records of fuel temperature, ambient temperature, and stack exhaust temperature will be maintained for the hot oil heaters.
DCP will demonstrate compliance with the CO_2 limits for all heaters based on metered fuel consumption and using the average high heat value (HHV) calculated according to the requirements at§98.33(a)(2)(ii), and the default CO_2 emission factor for natural gas from 40 CFR Part 98 Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(2)(i) is as follows:

$$CO_2 = 1x10^{-3} * Fuel * HHV * EF * 1.102311$$

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).

HHV = Annual average high heat value of the gaseous fuel (MMBtu/scf). The average HHV shall be calculated according to the requirements at §98.33(a)(2)(ii).

EF = Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2/MMBtu).

$1x10^{-3}$ = 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 DCP may install, calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

The emission limits associated with the greenhouse gases, CH_4 and N_2O, are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall emissions from the heaters 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, as published on October 30, 2009 (74 FR 56395). Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month rolling basis.

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

XI. Regeneration Heaters (HTR1 and HTR2)

Each fractionation train has a molecular sieve dehydrator regeneration heater (HTR1 and HTR2). Heat needed to regenerate the molecular sieve dehydrator beds is provided by the regeneration heaters. The regeneration heaters each have a maximum rated capacity of 36 MMBtu/hr. It is estimated they will each operate for 6,000 operating hours per year at the maximum firing rate, plus 2,760 operating hours per year in standby mode at the pilot firing rate of 0.4 MMBtu/hr.

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.
- *Use of Efficient Process Controls, Good Combustion Practices, and Scheduled Maintenance* – Use of these measures would ensure the heaters are operating as efficiently as possible.
- *Selection of Low Carbon Fuels* – Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input.

Step 2 – Elimination of Technically Infeasible Alternatives

The control technologies identified in step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- CCS
- Selection of Low Carbon Fuels
- Use of Efficient Process Controls, Good Combustion Practices, and Scheduled Maintenance

CCS is capable of achieving 90% reduction of generated CO_2 emissions and thus is considered to be the most effective control method. Use of low carbon fuels, efficient process controls, good combustion, and scheduled maintenance are all considered effective, can be used in tandem, and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only (and is not especially meaningful, given that these technologies are not mutually exclusive).

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 Storage (CCS)</u>

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

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Use of Low Carbon (Natural Gas) Fuel

Natural gas is the lowest carbon fuel available for use in the proposed heaters. Natural gas is a very clean burning fuel with respect to criteria pollutants and thus has minimal environmental impact compared to other fuels.

Process Controls, Good Combustion Practices, and Maintenance

The use of efficient process controls, good combustion practices, and scheduled maintenance will ensure the hot oil heaters are operating as efficiently as possible. Furthermore, proper operation of the hot oil heaters will extend their useful life and have no negative environmental or energy impacts.

Step 5 – Selection of BACT

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

Company / Location	Process Description	BACT Control(s)	BACT Emission Limit / Requirements	Year Issued	Reference
Energy Transfer Company (ETC), Jackson County Gas Plant Ganado, TX	4 Hot Oil Heaters (48.5 MMBtu/hr each) 4 Trim Heaters (17.4 MMBtu/hr each) 4 Molecular Sieve Heaters (9.7 MMBtu/each) 4 Regenerator Heaters (3 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit for process heaters per plant (one of each heater per plant) of 1,102.5 lbs CO_2/MMSCF 365-day average, rolling daily for each plant	2012	PSD-TX-1264-GHG
Enterprise Products Operating LLC, Eagleford Fractionation Mont Belvieu, TX	NGL Fractionation 2 Regenerant Heaters (28.5 MMBtu/hr each	Good Design & Combustion Practices	Regenerant heaters only have good combustion practices.	2012	PSD-TX-154-GHG

Company / Location	Process Description	BACT Control(s)	BACT Emission Limit / Requirements	Year Issued	Reference
Energy Transfer Partners, LP, Lone Star NGL Mont Belvieu, TX	2 Regenerant Heaters (46 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	Regenerator Heaters - 470 lbs CO_2/bbl of NGL processed. 365-day average, rolling daily	2012	PSD-TX-93813-GHG
Copano Processing L.P., Houston Central Gas Plant Sheridan, TX	2 Supplemental Heaters (25 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices, and Limited Operation	Each heater will be limited to 600 hours of operation on a 12-month rolling basis.	2013	PSD-TX-104949-GHG
Targa Gas Processing, Longhorn Gas Plant Decatur, TX	Hot Oil Heater (98 MMBtu/hr)	Energy Efficiency/ Good Design & Combustion Practices	BACT limit is combined with a TEG Glycol Reboiler and a Molecular Sieve Regen Heater. 1,783 lb CO_2/MMBtu on a 365-day rolling basis.	2013	PSD-TX-106793-GHG

The regeneration heaters proposed by DCP are rated at 36 MMBtu/hr. This falls within the range of previously permitted regeneration heaters identified in the table above. DCP proposes to limit the operation of each regeneration heater to 6,000 hours per year at the maximum firing rate (36 MMBtu/hr) and 2,760 hours per year they will be operated in standby mode at the pilot firing rate (0.4 MMBtu/hr). DCP will also monitor the thermal efficiency of the heaters on a semiannual basis and maintain a minimum thermal efficiency of 80% on an annual average. The regeneration heaters operate cyclically and the parameters required to demonstrate thermal efficiency are not recorded at a frequency to allow a calculation on a 12-month rolling average basis and therefore, DCP will determine thermal efficiency through semiannual stack testing during which exhaust temperature, fuel temperature, ambient temperature, and excess oxygen are measured and from which thermal efficiency can be calculated. EPA analyzed the proposed BACT and has determined it is consistent with other BACT determinations for similar units.

The following specific BACT practices are proposed for the regeneration heaters:

- *Use of Efficient Process Controls, Good Combustion Practices, and Scheduled Maintenance* – The proposed plant design includes specifications for state-of-the art process instrumentation and controls. Process instrumentation and controls for the molecular sieve dehydrator regeneration heaters include mole sieve bed temperature monitors and moisture analyzers to ensure proper regeneration of the mole sieve dehydration beds. DCP will follow the recommended maintenance schedule from the regeneration heater manufacturer. The heaters will maintain a minimum thermal efficiency of 80% based on semi-annual testing.

- *Selection of Low Carbon Fuels* – Pipeline quality natural gas will be the only fuel fired in the proposed heaters. It is the lowest carbon fuel available for use at the Jefferson County NGL Fractionation Plant.

The following monitoring and work practice requirements proposed by DCP will assist in maintaining the annual emission limits for the regeneration heaters:

- Use of natural gas as fuel.
- Installation of insulation where feasible on heater surfaces.
- Perform annual maintenance as recommended by the manufacturer and maintain records of maintenance activities.
- Install a totalizing fuel flow meter (calibrated annually) to continuously monitor fuel usage and record daily fuel consumption.
- Install a non-resettable hour meter to continuously record hours of operation.
- Monitor exhaust oxygen content using a portable stack gas analyzer to allow manual adjustment to optimize fuel/air mixture and limit excess air.
- Exhaust oxygen content will be monitored semi-annually for a period of 15 minutes and recorded at the beginning and end of the 15 minute period. If monitoring indicates an exhaust oxygen content of greater than 15% O_2, then the air /fuel mixture will be manually adjusted and the exhaust monitored again after adjustment to verify the oxygen content does not exceed 15% O_2.
- Exhaust oxygen content will be limited to a maximum of 15% O_2 based on the semiannual monitoring.
- Semiannual analysis of plant natural gas fuel to determine the higher heating value in Btu/scf, molecular weight, and carbon content, or certification from natural gas fuel supplier containing the same information.

BACT Limits and Compliance:

DCP shall demonstrate compliance with an 80% thermal efficiency on each of the regeneration heaters, which corresponds to an annual emission limit of 12,970 tpy CO_2e for each regeneration heater. The annual emission limit includes MSS emissions. The regeneration heater parameters for exhaust temperature, fuel temperature, ambient temperature, and excess oxygen will be monitored semiannually during stack testing. DCP will calculate the thermal efficiency based on this data semiannually and calculate a rolling annual average using the two most recent semiannual tests using equation G-1 from American Petroleum Institute (API) methods 560 (4^{th} ed.) Annex G.

DCP will demonstrate compliance with the CO_2 limits for all heaters based on metered fuel consumption and using the average high heat value (HHV) calculated according to the requirements at§98.33(a)(2)(ii), and the default CO_2 emission factor for natural gas from 40 CFR Part 98 Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(2)(i) is as follows:

$$CO_2 = 1x10^{-3} * Fuel * HHV * EF * 1.102311$$

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).
HHV = Annual average high heat value of the gaseous fuel (MMBtu/scf). The average HHV shall be calculated according to the requirements at §98.33(a)(2)(ii).
EF = Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2/MMBtu).
$1x10^{-3}$ = 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 DCP may install, calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

The emission limits associated with the greenhouse gases, CH_4 and N_2O, are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall emissions from the heaters 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, as published on October 30, 2009 (74 FR 56395). Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month rolling basis.

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

XII. Thermal Oxidizers (EPNs: TO1 and TO2)

The Thermal Oxidizers (TOs) are used to control waste gas streams from the amine vent, gasoline treater flash pot, and seal gas leaks. GHG emissions from the thermal oxidizers will result from waste gas and fuel gas combustion. The thermal oxidizer will have a hydrocarbon destruction and removal efficiency (DRE) of 99.9%.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Use of a Regenerative Thermal Oxidizer* **–** Use of a regenerative thermal oxidizer (RTO) would allow the plant to recover heat from the exhaust stream, reducing the overall heat input of the plant.
- *Efficient Process Controls, Good Combustion Practices, and Scheduled Maintenance* **–** These would ensure the TOs are operating as efficiently as possible.
- *Low Carbon Fuel* **–** Selection of a lower carbon fuel would result in less CO_2 formed during combustion.
- *CCS* **–** 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

The use of an RTO is considered technically infeasible. Use of an RTO requires a waste stream with a very low heating value (less than 50 Btu/scf). The waste gases from the process streams to be controlled have a much higher heating value (approximately 800 - 1,000 Btu/scf) than those normally combusted in an RTO. Use of an RTO to combust a stream with a heating value in the range of 800 - 1,000 Btu/scf could lead the RTO overheating, creating an unsafe situation. Therefore, the use of an RTO has been eliminated as BACT.

The remaining control technologies are considered technically feasible.
Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- CCS
- Selection of Low Carbon Fuels
- Use of Efficient Process Controls, Good Combustion Practices, and Scheduled Maintenance

CCS is capable of achieving 90% reduction of generated CO_2 emissions and thus is considered to be the most effective control method. Use of low carbon fuels, efficient process controls, good combustion, and scheduled maintenance are all considered effective, can be used in tandem, and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only (and is not especially meaningful, given that these technologies are not mutually exclusive).

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

Carbon Capture and Storage

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

The remaining options for control of CO_2 from the TOs is to use a low carbon fuel and use efficient process controls, good combustion practices, and maintenance. There are no negative economic, energy, or environmental impacts associated with these options.

Step 5 – Selection of BACT

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

- *Efficient Process Controls, Good Combustion Practices, and Scheduled Maintenance* **–** These would ensure the TOs are operating as efficiently as possible.
- *Low Carbon Fuel* **–** Use of pipeline quality natural gas.

DCP proposes the following monitoring and work practice requirements for the TOs, which address both fuel gas and waste gas combustion:

- Perform annual maintenance as recommended by the manufacturer and maintain records of maintenance activities.
- Monitor the temperature at the firebox exit to ensure 99.9% DRE for VOC and methane. The minimum temperature which demonstrates 99.9% DRE will be determined by initial performance testing. The minimum temperature will be determined every 3 years following initial testing. The Permittee shall submit testing data to EPA for approval of the minimum temperature to be maintained.
- Initial performance test to establish firebox exit temperature necessary to demonstrate 99.9% DRE, subsequent performance testing to be performed every 3 years thereafter.
- Continuous monitoring of the firebox exit temperature, reduced to an hourly and daily average, to demonstrate compliance with the specified DRE.
- Monitor fuel usage continuously using a totalizing fuel flow meter (calibrated annually) and record daily fuel consumption.

- Monitor flow rate of waste gas continuously using a totalizing flow meter (calibrated annually) and record daily waste gas flow.
- Sample waste gas quarterly to determine composition and heat content.
- Semiannual analysis of plant natural gas fuel to determine the higher heating value in Btu/scf, molecular weight, and carbon content, or certification from the natural gas fuel supplier containing the same information.

Based on the identified control technologies and the proposed work practice standards, an emission limit for each thermal oxidizer of 8,824 tpy CO_2e is proposed. 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)].

XIII. Analyzer Catalytic Oxidizers (EPNs: TE1 and TE2)

A combination of the plant flare and the Analyzer Catalytic Oxidizers (TRACErase™ technology or equivalent technology) are used to safely dispose of intermittent sample purge gas from various analyzers used throughout the process in both trains. It is not technically feasible to control these sample purge gas streams with the thermal oxidizer due to their intermittent nature. The significant portion of each analyzer sample purge gas stream is routed to the plant flare for control; however, a small portion (approximately 1.2%) of each sample purge gas stream is routed to the analyzer catalytic oxidizer in each train for control. Control technologies for emissions to and from the flare are addressed in Section XIV.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Routing Analyzer Purge Gas to the Flare* – Routing the analyzer sample purge gas to the flare would result in elimination of the analyzer catalytic oxidizer emission sources while maintaining similar control efficiency for the purge gas streams.
- *Minimization of Releases sent to the TE System* – Minimization of the sample purge gas releases to the analyzer catalytic oxidizer would minimize GHG emissions from the TE systems.

Step 2 – Elimination of Technically Infeasible Alternatives

<u>Routing Analyzer Purge Gas to the Flare</u>

Routing the analyzer sample purge gas streams to the flare would result in backpressure on the analyzer systems. Backpressure on the analyzer systems would result in inaccurate operation of the analyzer systems; therefore, routing these streams to the flare is considered technically infeasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Only one control technology remains, therefore, there ranking is not needed.

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

Minimization of Releases

Minimization of the small analyzer sample purge gas releases to the analyzer catalytic oxidizer is the only remaining control technology. There are not any negative economic, energy, or environmental impacts associated with this control.

Step 5 – Selection of BACT

EPA identified one other facility that was proposed to have analyzer catalytic oxidizers. This facility is the ExxonMobil Mont Belvieu Plastics Plant. The ExxonMobil facility will have up to 35 analyzers equipped with catalytic oxidizers and emissions are estimated to be 28 TPY of CO_2e. ExxonMobil proposed to perform preventative maintenance annually, to include cartridge replacement as BACT. DCP is installing fewer analyzer catalytic oxidizers in comparison to ExxonMobil. For DCP it was determined that work practice standards, limiting the flow to the analyzers, and annual catalyst cartridge replacement are the methods that will be used to implement the minimization of releases selected as BACT.

Minimization of releases of the small portion of the analyzer sample purge gas streams to the analyzer catalytic oxidizers has been selected as BACT by DCP. DCP will operate the plant in a manner that will minimize analyzer sample purge gas streams sent to the analyzer catalytic oxidizers. DCP proposes to minimize GHG emissions from the analyzer catalytic oxidizers using the following monitoring and work practice requirements:

- Maintain the process analyzers and analyzer catalytic oxidizers according to the manufacturer instructions with the frequency recommended by the manufacturer.
- Maintain records of maintenance performed on the process analyzers.
- Maintain records of maintenance performed on the analyzer catalytic oxidizers.
- Annual preventative maintenance to include replacement of the catalyst cartridge.
- Limit waste gas volume sent to each of the analyzer catalytic oxidizers to 5,520 scf per year on a 12-month rolling basis.

The work practice standards above correlate to an emission limit of 1.1 TPY of CO_2e for each analyzer catalytic oxidizer.

XIV. Flare (EPN: FLR1)

The plant flare is used to safely dispose of intermittent waste streams that are not technically feasible to control with the thermal oxidizer. The flare will control emissions associated with emergency releases of hydrocarbons and from maintenance, startup, and shutdown (MSS) events from both fractionation trains. The flare is air assisted with a hydrocarbon destruction and removal efficiency of at least 98%. These streams contain VOCs that when combusted by the flare produce CO_2 emissions. The flare's pilots are fueled by pipeline quality natural gas. The maintenance activities that may be routed to the flare, along with the material flared, and frequency, are identified in Attachment B of the revised GHG PSD permit application submitted on February 27, 2013.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Flaring Minimization* – Minimize the duration and quantity of flaring to the extent possible through good engineering design of the process and good operating practices.
- *Proper Operation of the Flare* – Use of flow and composition monitors to accurately determine the optimum amount of natural gas required to maintain adequate VOC destruction in order to minimize natural gas combustion and the resulting CO_2.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Section X, Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Flare minimization and proper operation of the flare are potentially equally effective but have case-by-case effectiveness that cannot be quantified to allow ranking.

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

Use of an analyzer(s) to determine the heating value of the gas to allow continuous determination of the amount of natural gas needed to maintain a minimum heating value of 300 Btu/scf to insure proper destruction of VOCs ensures that excess natural gas is not unnecessarily flared. This added advantage of reducing fuel costs makes this control option cost effective as both a criteria pollutant and GHG emission control option. There are no negative environmental impacts associated with this option. Proper design of the process equipment to minimize the quantity of waste gas sent to the flare also has no negative economic or environmental impacts.

Step 5 – Selection of BACT

DCP proposes to use both identified control options to minimize GHG emissions from flaring of intermittent waste gas stream, MSS emissions, and emergency releases from the proposed facilities. The following specific BACT practices are proposed for the flare:

- *Flaring Minimization* – DCP will operate the plant in such a way as to minimize release streams sent to the flare. This method of operation will result in less GHG emissions from the flare. DCP will minimize release streams using the following methods:
    - Intermittent emissions to the flare will be minimized by proper maintenance of the process equipment according to written mechanical integrity program procedures and limiting sample and analyzer purges to only those required to maintain the desired product quality.
    - Maintaining the plant processes at regular intervals as described in the permit application will avoid additional MSS operations, thereby minimizing emissions to the flare.
    - Process fluids in equipment that requires maintenance will be routed into the process until no longer operationally feasible; thereby minimizing the amount of process material routed to the flare.
    - Emergency emissions to the flare will be minimized by proper process design and training of process operators to avoid significant overpressure incidents to the flare.
- *Proper Operation of the Flare* – Flow rate and gas composition analyzers shall be used to continuously monitor the combined waste gas stream sent to the flare from the proposed and other existing facilities to determine the quantity of natural gas required to maintain a minimum heating value of 300Btu/scf. The flow rate and gas composition analyzer shall continuously sample and record the molecular weight and mass flow rate of the flare gas consistent with the stream analyzer frequency.

DCP proposes the following monitoring and work practice requirements to assist in maintaining the destruction efficiency and emission limit for the flare:

- The proposed flare will burn pipeline quality natural gas in the pilots.
- The flare will be designed and operated in accordance with 40 CFR 60.18.
- Continuously monitor for the presence of pilot flame using a thermocouple or the equivalent device.
- Install a totalizing fuel flow meter (calibrated quarterly) to determine the volume of natural gas fuel combusted in the flare pilots.
- Install a totalizing flow meter (calibrated quarterly) to measure the flare header purge gas and waste gas volume sent to the flare.

- Maintain records of the monthly natural gas combusted, semiannual natural gas analysis, and the monthly waste gas volume.
- Install a gas analyzer (gas chromatograph or equivalent) on the header piping directly upstream of the inlet to the flare to measure composition and heat input of the flare header purge gas and waste gas for each intermittent and MSS vent stream.

Use of these practices corresponds with a permit emission limit of 9,447 tpy CO_2e. The annual emission limit includes MSS emissions. DCP will demonstrate compliance with the CO_2 emission limit using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1, and the gas analyzer data of the intermittent and MSS vent streams. The emission limits associated with CO_2, CH_4, and N_2O are calculated based on methodology provided in 40 CFR §98.233(n)(4) through (n)(8) using the site specific analysis of process fuel gas, and the actual heat input (HHV) and converted to short tons.

XV. Emergency Firewater Pump Engine (EPN: ENG1) and Emergency Generator Engine (EPN: ENG2)

DCP will install one emergency backup generator and one emergency firewater pump engine. Each engine will be rated at 500 HP. The generator and engines proposed for use will operate at a low annual capacity factor - approximately one hour per week in non-emergency use. The generator and 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. The emergency firewater pump engine will supply power to a firewater pump and will comprise a new firewater system. The emergency firewater pump engine will have a power output of 500 HP. The CO_2e emissions from the emergency generator and the firewater pump engine account for less than 0.01% of the total project emissions.

Step 1 – Identification of Potential Control Technologies

- *Selection of Energy Efficient Engines* – Selection of energy efficient engines would reduce the total heat input of the plant and the emissions associated with the engines.
- *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.
- *Process Controls, Good Operating, and Maintenance Practices* – Good operating and maintenance 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* – The purpose of the engines is to provide a power source during emergencies, which include site power outages and natural disasters, such as hurricanes. As such, the power source must be available during emergencies. Electricity is not a source that is available during a power outage, which is the specific event for which the backup generators are designed to operate. Natural gas supply may be curtailed during an emergency such as a hurricane; thereby not providing fuel to the engines during the specific event for which the backup generators and firewater booster pump are designed to operate. The National Fire Protection Association (NFPA) requires that firewater pump engines meet the NFPA 20 Standard (Standard for the Installation of Stationary Pumps for Fire Protection). NFPA 20 does not allow the use of spark ignition (SI) internal combustion engines to drive firewater pumps, which would include engines that use natural gas fuel. The engines must be powered by a liquid fuel that can be stored in a tank and supplied to the engines on demand, such as motor gasoline or diesel. Therefore, DCP proposes to use diesel fuel for the emergency generator engines and firewater booster pump 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.
- *Process Controls, Good Operating Combustion Practices and Maintenance* – Is considered technically feasible.
- *Selection of Efficient Engines* – Is considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Both remaining options, selection of efficient engines and, process control, good operation, and maintenance practices, are both considered effective and have a range of efficiency improvements which cannot be directly quantified; 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 remaining options for control of CO_2 from engines is to select energy efficient engines and follow good operating and maintenance practices. There are no negative economic, energy, or environmental impacts associated with these options.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the engines:

- *Selection of Energy Efficient Engines* – The selected engines are required to be available for use at any time in the event of an emergency, including when natural gas is not available.
- *Process Controls, Good Operation, and Maintenance Practices* – State of the art process instrumentation and controls will be utilized. Good operation and maintenance 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.

DCP proposes the following monitoring and work practice requirements for each engine:

- Emergency Firewater Pump Engine
    - Fuel used in the engine will meet the requirements of 40 CFR 80.510(b) regarding sulfur content (15 ppmw maximum) and a minimum Cetane Index of 40 or maximum aromatic content of 35% by volume.
    - Installation of a non-resettable hour meter prior to start-up of the engine.
    - Operate and maintain the engine and control device according to the manufacturer's emission-related written instructions.
    - Engine purchased will be certified to meet the applicable emission standards of 40 CFR 60.4205(c).
    - The engine may be operated for the purpose of maintenance checks and readiness testing for up to 100 hours per year.

- Emergency Generator Engine
    - Fuel used in the engine will meet the requirements of 40 CFR 80.510(b) regarding sulfur content (15 ppmw maximum) and a minimum Cetane Index of 40 or maximum aromatic content of 35% by volume.
    - Installation of a non-resettable hour meter prior to start-up of the engine.
    - Operate and maintain the engine and control device according to the manufacturer's emission-related written instructions.
    - Engine purchased will be certified to meet the applicable emission standards of 40 CFR 60.4205(b).
    - The engine may be operated for the purpose of maintenance checks and readiness testing for up to 100 hours per year.

Using the operating and maintenance practices identified above results in an emission limit of 29 tpy CO_2e for each engines. DCP 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)(1)(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 obtained from company records.
HHV = Default high heat value of Distillate Fuel Oil No. 2 from Table C-1 to Subpart C of Part 98.
EF = Default CO_2 emission factor for Distillate Fuel Oil No. 2 from Table C-1 to Subpart C of Part 98.
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.

XVI. Process Fugitives (EPNs: FUG1 and FUG2)

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. The additional methane and CO_2 emissions from process fugitives have been conservatively estimated to be 297 tpy as CO_2e per train. 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

- *Leakless Component Designs*
- *Leak Detection and Repair (LDAR) Programs*

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

Both control technologies are being proposed as BACT; therefore, there is no need to rank them.

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

Although technically feasible, use of an LDAR program just to control the negligible amount of GHG emissions that occur as process fugitives is clearly cost prohibitive. However, if an LDAR program is being implemented for VOC control purposes, it will also result in effective control of the small amount of GHG emissions from the same piping components. DCP uses TCEQ's 28LAER[3] LDAR program at the Jefferson County NGL Fractionation Plant to minimize process fugitive VOC emissions at the plant, and this program has also been proposed for the additional fugitive VOC emissions associated with the project. 28LAER is TCEQ's most stringent LDAR program, developed to satisfy LAER requirements in ozone non-attainment areas. DCP will also utilize leakless components in their design where feasible.

Step 5 – Selection of BACT

Due to the negligible amount of GHG emissions from process fugitives, the only available control, implementation of an LDAR program, is clearly not cost effective as applied to GHGs alone. However, process lines in VOC service are proposed to incorporate the TCEQ 28LAER leak detection and repair (LDAR) program for fugitive emissions control in the NSR permit to be issued by TCEQ. DCP also identified and adopted the use of leakless fugitive components, where economical and feasible, to eliminate potential sources of fugitive emissions. Process lines contribute insignificant quantities of GHGs, less than 0.01% of project CO_2e emissions, and since they are proposed in the governing permit for lowest achievable emission rate controls, process lines in VOC service in the two proposed fractionation trains, EPA concurs with DCP's assessment that using the TCEQ 28LAER LDAR program is also an appropriate control of GHG emissions. As noted above, LDAR programs would not normally be considered for control of GHG emissions alone due to the negligible amount of GHG emissions from fugitives, and while the existing LDAR program is being imposed in this instance, the imposition of a numerical limit for control of those negligible emissions is not feasible.

XVII. 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 DCP Midstream LP ("DCP") and its consultant, Spirit Environmental, LLC ("Spirit"), as non-federal representatives for purposes of preparation of the BA.

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

A draft BA has identified nine (9) species listed as federally endangered or threatened in Jefferson County, Texas:

Federally Listed Species for Jefferson 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**
Birds	
Piping plover	*Charadrius melodus*
Fish	
Smalltooth sawfish	*Pristis pectinata*
Mammals	
Louisiana black bear	*Ursus americanus luterolus*
Red wolf	*Canis rufus*
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 DCP for construction of a new natural gas liquids fractionation plant at an existing facility will have no effect on the nine (9) listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.

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

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on 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.

XVIII. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on and adopted a cultural resource report prepared by SWCA Environmental Consultants ("SWCA") submitted on April 26, 2013.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 386.5 acres of land that includes 339 acres of the site facility that contains the construction footprint of the project, 46 acres for a 3.8-mile long pipeline corridor with 100 feet right-of-way, and 1.5 acres for 900 feet of a proposed water discharge line associated with this project. Following consultation with the State Historic Preservation Officer (SHPO), SWCA conducted a field survey of the APE and a desktop review on the archaeological background and historical records within a 1.0-mile radius 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.

Based on the desktop review for the site facility and the linear facilities, Spindletop Oil Field, which is listed in the NHRP and also listed as a National Historic Landmark (NHL), is located 0.92 miles from the project area. Numerous surveys have been performed within the Spindletop property and at least seven cultural surveys were previously conducted within a 1-mile radius of the APE. Ten historic sites associated with Spindletop Oil Field were identified and were located within 1 mile of the APE; two of those sites are within the APE along the proposed 3.8-mile long pipeline corridor. Both of those sites located within the APE did not meet the any criteria for NHRP listing and were therefore were not recommended to be eligible for listing on the National Register. Eleven other historic or archaeological sites were identified from previous reports, all of which are outside of the APE. Based on the results of the field survey, which included 223 shovel tests, of the site facility, water discharge pipeline and pipeline corridor, no intact archaeological resources or historic structures were found.

EPA Region 6 determines that issuance of the permit to DCP will not affect properties on or potentially eligible for listing on the National Register. Additionally, no historic properties are located within the APE and the potential for intact archaeological resources is low within the construction footprint of the project itself.

On April 30, 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.

XIX. Environmental Justice (EJ)

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

XX. Conclusion and Proposed Action

Based on the information supplied by DCP, our review of the analyses contained in 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 DCP 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[2,3]	BACT Requirements
				TPY[2]		
HOH1	HOH1	Hot Oil Heater Train 1	CO_2	78,422	78,500	Minimum Thermal Efficiency of 85%. See permit condition III.A.1.r.
			CH_4	1.48		
			N_2O	0.15		
HOH2	HOH2	Hot Oil Heater Train 2	CO_2	78,422	78,500	Minimum Thermal Efficiency of 85%. See permit condition III.A.1.r.
			CH_4	1.48		
			N_2O	0.15		
HTR1	HTR1	Regeneration Heater Train 1	CO_2	12,959	12,970	Minimum Thermal Efficiency of 80% and Limit of 6,000 hr/yr at Max Firing. See permit conditions III.A.2.i. and III.A.2.u.
			CH_4	0.24		
			N_2O	0.02		
HTR2	HTR2	Regeneration Heater Train 2	CO_2	12,959	12,970	Minimum Thermal Efficiency of 80% and Limit of 6,000 hr/yr at Max Firing. See permit conditions III.A.2.i. and III.A.2.u.
			CH_4	0.24		
			N_2O	0.02		
FLR1	FLR1	Flare	CO_2	7,215	9,447	Use of Good Combustion Practices. See permit condition III.A.5.
			CH_4	0.91		
			N_2O	7.14		
TO1	TO1	Thermal Oxidizer Train 1	CO_2	8,820	8,825	Minimum firebox temperature based on performance testing. See permit condition III.A.3.b and III.A.3.h.
			CH_4	0.07		
			N_2O	0.01		
TO2	TO2	Thermal Oxidizer Train 2	CO_2	8,820	8,825	Minimum firebox temperature based on performance testing. See permit condition III.A.3.b and III.A.3.h.
			CH_4	0.07		
			N_2O	0.01		
ENG1	ENG1	Firewater Pump Engine	CO_2	28.5	29	Good combustion practices, non-emergency operation limited to 100 hrs/year. See permit conditions at III.A.6.
			CH_4	0.02		
			N_2O	No Numerical Limit Established[4]		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
ENG2	ENG2	Emergency Generator Engine	CO_2	28.5	29	Good combustion practices, non-emergency operation limited to 100 hrs/year. See permit conditions at III.A.6.
			CH_4	0.02		
			N_2O	No Numerical Limit Established[4]		
TE1	TE1	Analyzer Catalytic Oxidizer Train 1	CO_2	1.1	1.1	Limit flow to 5,520 ft^3/yr. See permit condition III.A.4.c.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
TE2	TE2	Analyzer Catalytic Oxidizer Train 2	CO_2	1.1	1.1	Limit flow to 5,520 ft^3/yr. See permit condition III.A.4.c.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
FUG1 FUG2	FUG1 FUG2	Fugitive Process Emissions	CO_2	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Implementation of LDAR Program. See permit condition III.A.7.
			CH_4	No Numerical Limit Established[5]		
Totals[6]			**CO_2**	**207,676**	**CO_2e 210,137**	
			CH_4	**6.45**		
			N_2O	**7.5**		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month 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. The emissions 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 EPNs FUG1 and FUG2 are estimated to be 0.34 TPY of CO_2, 1.92 TPY of CH_4, and 40.7 TPY CO_2e. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
6. The total emissions for CO_2, CH_4, and CO_2e include the PTE for process fugitive emissions of CO2, CH_4, and CO_2e. These totals are given for informational purposes only and do not constitute emission limits.