Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
For Magellan Processing, L.P. (along with its affiliates)'s Corpus Christi Terminal

PSD Permit Number: PSD-TX-1398-GHG

October 2014

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

I. Executive Summary

On November 11, 2013, Magellan Processing, L.P. (along with its affiliates, "Magellan") submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) air quality permit application for Greenhouse Gas (GHG) emissions from a proposed modification at an existing stationary source. Magellan submitted additional information to EPA on March 19, 2014, April 4, 2014, and a final revised GHG PSD permit application on September 22, 2014 including all previous revisions. In connection with the same proposed project, Magellan submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on March 28, 2014. Magellan proposes to construct a new 100,000 barrels per day (bbl/day) condensate splitter plant at their existing Corpus Christi terminal, to be constructed in two phases. The proposed condensate splitter facility will have two trains each of which will process 50,000 bbl/day of hydrocarbon condensate material to obtain products suitable for commercial use including propane, butanes, light naphtha, heavy naphtha, kerosene, distillate, and resid (oil gas) product for sale to customers. The proposed condensate splitter facility will consist of processing equipment, various storage tanks and associated piping, loading and control equipment.

EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize modification and construction of air emission sources at the Corpus Christi terminal located in Corpus Christi, Nueces County, Texas.

EPA Region 6 concludes that Magellan's application is complete and provides all 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 Magellan, and EPA's own technical analysis. EPA is making this information available as part of the public record.

II. Applicant

Magellan Processing L.P.
Corpus Christi Terminal
One Williams Center, MD 27
Tulsa, OK 74172

Facility Physical Address:
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Corpus Christi, TX 78407

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III. Permitting Authority

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

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

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Quang Nguyen
Air Permitting Section (6PD-R)
1445 Ross Avenue
Dallas, TX 75202
(214) 665-7238

IV. Facility Location

The proposed Condensate Splitter is located in Corpus Christi, Nueces County, Texas. Nueces County is currently designated attainment for all criteria pollutants. 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 proposed facility site are as follows:

Latitude: 27° 48' 29.34"
Longitude: 97° 26' 12.25"

The Figures 1 and 2 illustrate Corpus Christi Terminal location and the proposed site layout for this draft permit.

Figure 1 – Process Area Plot Plan

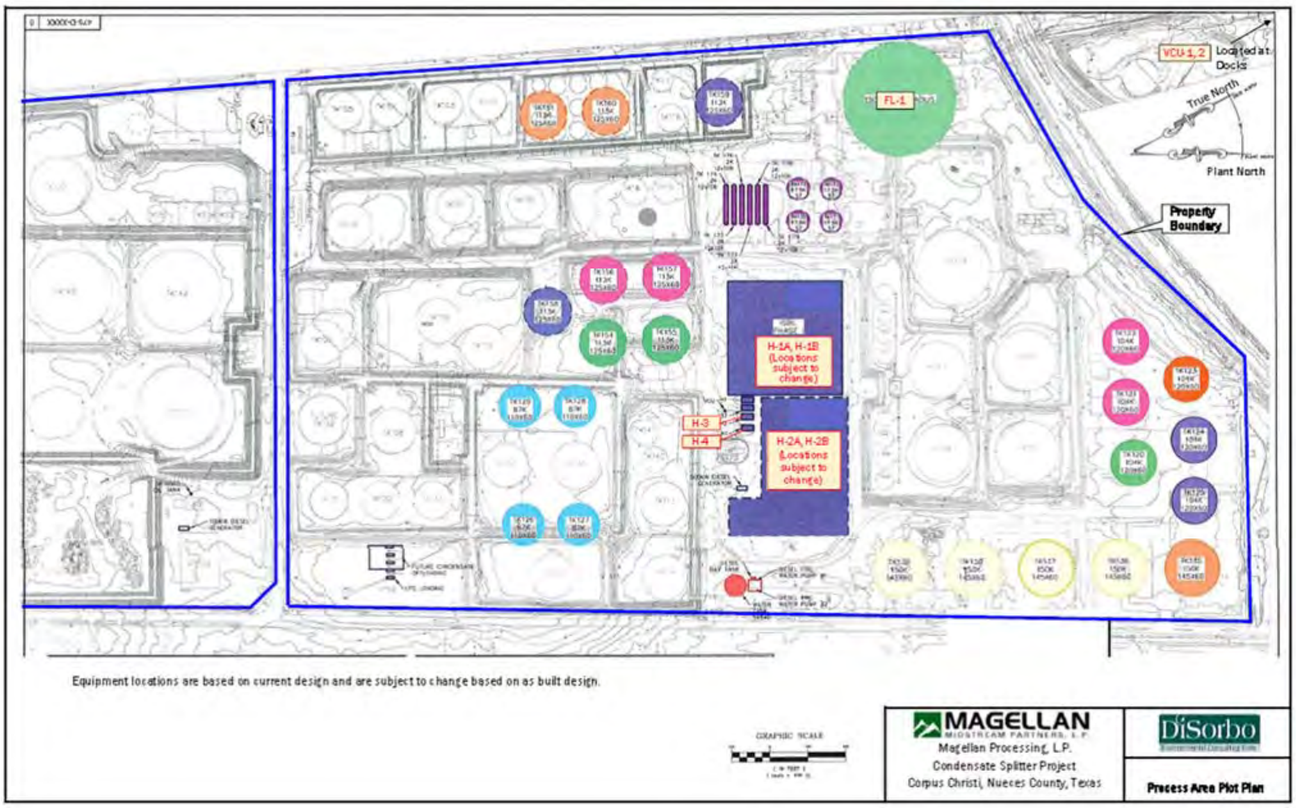
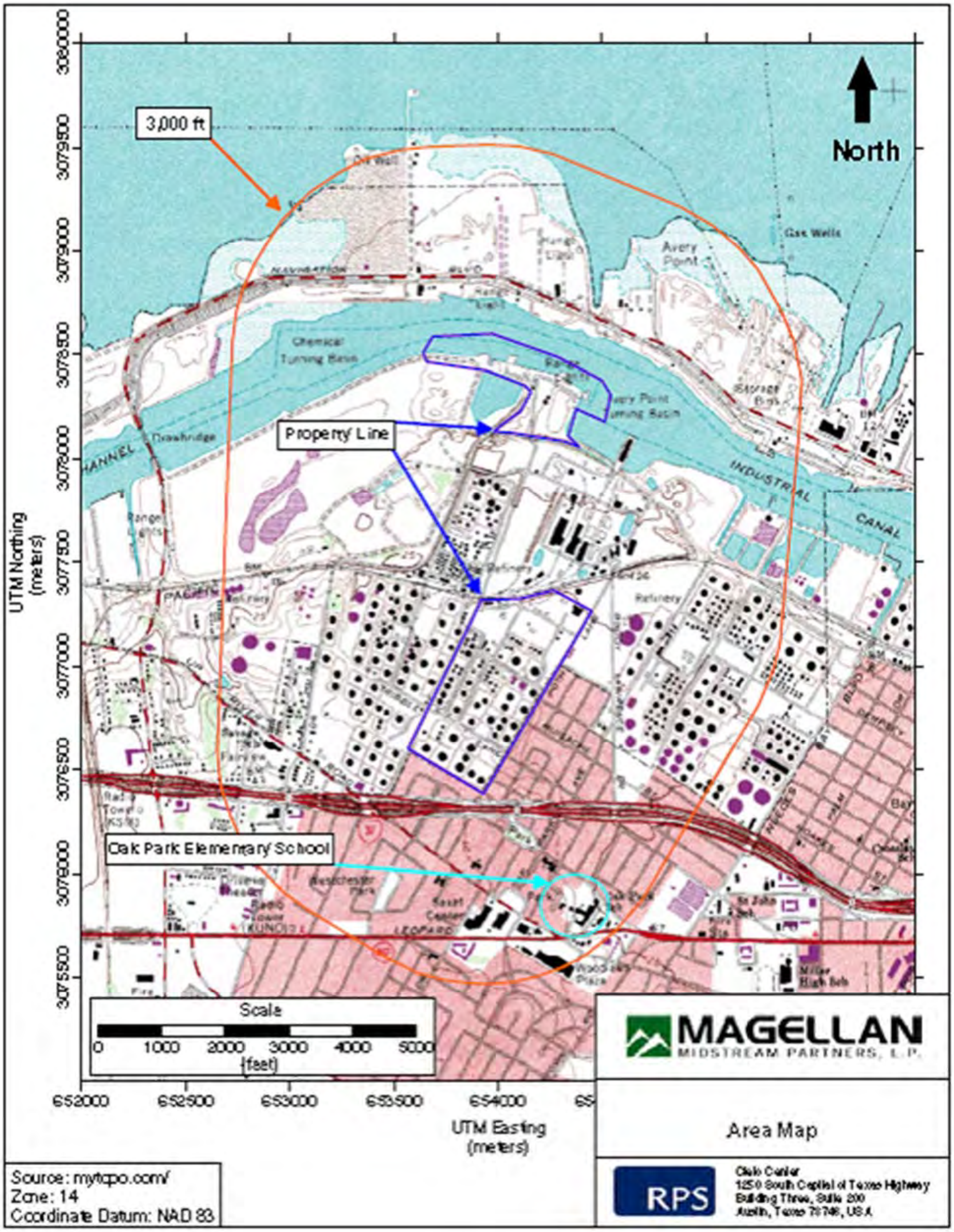


Figure 2 – Area Map



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

EPA Region 6 implements a GHG PSD FIP for the State of Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305. On June 23, 2014, the United States Supreme Court issued a decision addressing the application of stationary source permitting requirements to GHGs. *Utility Air Regulatory Group 124 S.Ct.2427 (2014).* The Supreme Court said that EPA may not treat greenhouse gases as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or Title V permit. The Court also said that EPA could continue to require that PSD permits that are otherwise required based on emissions of conventional pollutants contain limitations on GHG emissions based on the application of Best Available Control Technology (BACT). Pending further EPA engagement in the ongoing judicial process before the United States Court of Appeals for the D.C. Circuit, EPA is proposing to issue this permit consistent with EPA's understanding of the Supreme Court's decision.

The source is a major stationary source for PSD because the facility has the potential to emit over 250 tpy of VOC. In this case, the applicant represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, has determined the project is subject to PSD review for VOC.

The applicant also estimates that this same project will result in a GHG emissions increase and a GHG net emissions increase of 226,502 tpy CO_2e and 226,117 tpy[1] on a mass basis, which exceeds the GHG thresholds in EPA regulations. 40 C.F.R § 52.21(b)(49)(iv); see also, *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) at 12-13. Since the Supreme Court recognized EPA's authority to limit application of BACT to sources that emit GHGs in greater than *de minimis* amounts, EPA believes it may apply the 75,000 tons per year threshold in existing regulations at this time to determine whether BACT applies to GHGs at this facility.

Thus, this project requires a PSD permit that includes limitations on GHG emissions based on application of BACT. The Supreme Court's decision does not materially limit the FIP authority and responsibility of Region 6 with regard to this particular permitting action. Accordingly,

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[1] Two existing marine vessel loading vapor combustion units (EPNs: VCU1 and VCU2) and one existing tank heater (EPN: H-3) at the Corpus Christi Terminal will be used as part of the condensate splitter process but are not being physically modified themselves. They have a total estimated GHG emissions of 15,723 tpy CO_2e. As explained in the GHG Permitting Guidance, for the purposes of determining whether a PSD permits is required, the EPA requires a permitting authority to look beyond the emissions unit that is modified (across the entire source) to determine the extent of emission increases that result from the modification. However, the BACT applies only to the emission unit(s) that have been modified or added to the existing facility. See PSD and Title V permitting Guidance for Greenhouse Gases at 23. As a result, any additional GHG emissions from the condensate splitter process have been included in calculating the total tpy CO_2e to determine the PSD applicability. EPA will not, however, conduct a BACT analysis for the existing marine vessel loading vapor combustion units (VCU1 and VCU2) and tank heater (H-3) as part of this permit.

under the circumstances of this project, the TCEQ will issue the non-GHG portion of the permit and EPA will issue the GHG portion.[2]

In issuing GHG permits, EPA Region 6 follows the policies and practices reflected in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011). For the reasons described in that guidance, we have not 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 believes 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 regulated NSR pollutants that are non-GHG pollutants, which are addressed by the PSD permit to be issued by TCEQ.

VI. Project Description

Magellan is proposing to construct a condensate splitter plant that is designed to process 100,000 barrels per day (bbl/day) of hydrocarbon condensate material to obtain products suitable for commercial use including propane, butanes, light naphtha, heavy naphtha, kerosene product, and distillate product for sale to customers. Magellan proposes to construct the condensate splitter plant at their existing Corpus Christi Terminal located in Corpus Christi, Nueces County, Texas. The Corpus Christi Terminal is a for-hire bulk petroleum storage terminal. Petroleum products and specialty chemicals are stored in various storage tanks and transferred in and out of the terminal tankage for external customers via pipeline, tank truck, railcar, and marine vessel. The proposed condensate splitter plant will consist of a pre-fractionator column, a main fractionation column, six heaters, a flare, three vapor combustors, four emergency engines, and 27 storage tanks.

Magellan proposes to construct the condensate splitter facility in two phases. It will consist of two process trains (Train 1 and Train 2). Each train will process 50,000 bbl/day of hydrocarbon condensate material. Construction of the second 50,000 bbl/day train (Train 2) will commence within 18 months of the completion of the first 50,000 bbl/day train. Table 1 below identifies under which phase of construction each emission point will be constructed. Train 1 and 2 will be constructed in Phase 1 and 2, respectively.

[2] *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

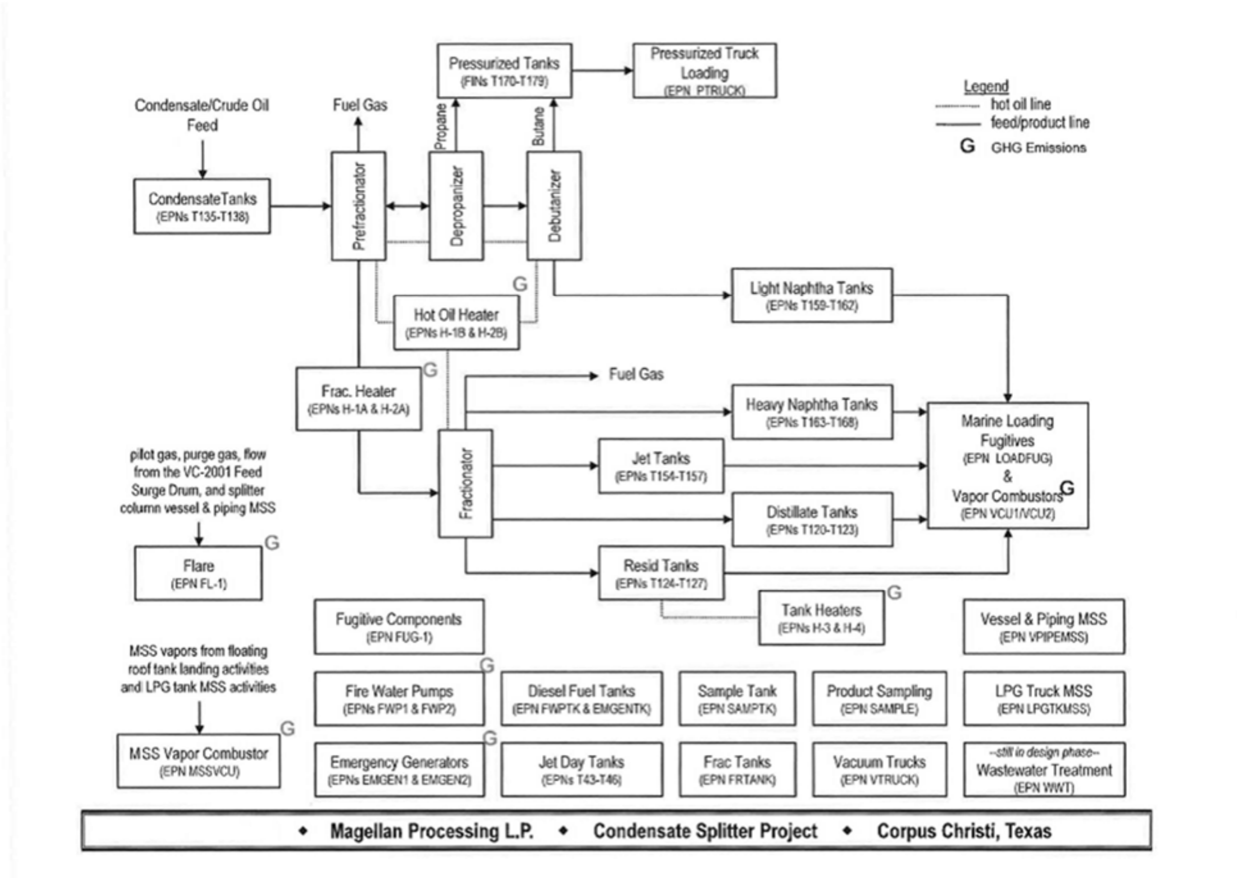
Table 1. Magellan Condensate Splitter Project – GHG EPNs Construction		
Process Equipment Description	**EPN**	**Phase**
Natural Gas and Fuel Gas-Fired Fractionator Heater	H-1A	1
Natural Gas and Fuel Gas-Fired Fractionator Heater	H-2A	2
Natural Gas and Fuel Gas-Fired Hot Oil Heater	H-1B	1
Natural Gas and Fuel Gas-Fired Hot Oil Heater	H-2B	2
Flare	FL-1	1
Tank Heater	H-3	Existing[1]
Tank Heater	H-4	1
Natural Gas Fugitives	FUG-1	1
Fire Water Pump Engine	FWP1	1
Fire Water Pump Engine	FWP2	1
Emergency Generator Engine	EMGEN1	1
Emergency Generator Engine	EMGEN2	1
Vapor Combustor	VCU1	Existing[1]
Vapor Combustor	VCU2	Existing[1]
MSS Vapor Combustor	MSSVCU	1

1 This emission unit is an existing non-modified unit. It is not subject to permit requirements since this unit will not be physically modified.

For Phase 1 and 2 combined, Magellan proposes to install the following units: two natural gas/fuel gas-fired hot oil heaters, two natural gas/fuel gas-fired fractionator heaters, one natural gas-fired tank heater, one process flare, one vapor combustor for planned Maintenance, Startup, and Shutdown activities, two diesel-powered fire pump engines, two diesel-powered emergency generators, nineteen internal floating roof storage tanks, seven vertical fixed roof storage tanks, and ten pressurized storage tanks. Figure 3 shows the simplified process flow diagram. GHG emissions will result from the following emission units:

- Two Natural Gas/Fuel Gas-Fired Hot Oil Heaters (EPNs: H-1B and H-2B);
- Two Natural Gas/Fuel Gas-Fired Fractionator Heaters (EPNs: H-1A and H-2A);
- One Natural Gas-Fired Tank Heater (EPN: H-4)
- One Flare (EPN: FL-1);
- Two Diesel-Powered Fire Water Pump Engines (EPNs: FWP1 and FWP2);
- Two Diesel-Powered Emergency Generators (EPNs: EMGEN1 and EMGEN2);
- One Vapor Combustion Unit for planned Maintenance, Startup and Shutdown activities (EPN: MSSVCU) ; and
- Fugitive Emissions from Piping Components (EPN: FUG-1).

Figure 3 – Simplified Process Flow Diagram



1. Heaters (EPNs: H-1A, H-2A, H-1B, H-2B, and H-4)

The new condensate splitter process will include a new natural gas/fuel gas-fired hot oil heater and a new natural gas/fuel gas-fired fractionator heater for each train. These heaters will be equipped with ultra-low NOx burners and selective catalytic reduction controls to reduce NOx emissions. GHG emissions, primarily CO_2, are generated from the combustion of natural gas and fuel gas produced by the splitter process. The maximum and annual average firing rates of each of the two hot oil heaters will be 105.8 MMBtu/hr and 96.2 MMBtu/hr, respectively. For the two fractionator heaters, each will have a maximum and annual average firing rates of 128.9 MMBtu/hr and 117.2 MMBtu/hr, respectively. In addition, two 16 MMBTU/hr natural gas-fired tank heaters, one new and one existing non-modified heater, will be used at the facility. The four larger gas-fired heaters (two Hot Oil and two Fractionator Heaters) will account for about 90 percent of the Splitter Project GHG Emissions. Potential heater GHG emissions are provided in Table 2.

Table 2. Estimated Heater GHG Emissions				
Source	**Pollutant**	**Emissions (tpy)**	**GWP [1]**	**CO_2e (tpy)**
Fractionator Heater (H-1A)	CO_2	60,049	1	60,111
	CH_4	1.13	25	
	N_2O	0.11	298	
Fractionator Heater (H-2A)	CO_2	60,049	1	60,111
	CH_4	1.13	25	
	N_2O	0.11	298	
Hot Oil Heater (H-1B)	CO_2	49,289	1	49,340
	CH_4	0.93	25	
	N_2O	0.09	298	
Hot Oil Heater (H-2B)	CO_2	49,289	1	49,340
	CH_4	0.93	25	
	N_2O	0.09	298	
Tank Heater (H-4)	CO_2	4,099	1	4,103
	CH_4	0.075	25	
	N_2O	0.01	298	

1 GWP factors from 40 CFR 98, Table A-1.

2. Flare (EPN: FL-1)

An elevated process flare is, generally, used in emergency overpressure situations and during planned maintenance, startup, and shutdown (MSS) activities to dispose of excess process vapors. The new condensate splitter plant will utilize a process flare for control of venting during planned MSS and upset situations. Its destruction efficiency rating is 99% for VOC compounds containing no more than 3 carbons (that contain no elements other than carbon and hydrogen) in addition to the following compounds: methanol, ethanol, propanol, ethylene oxide, and propylene oxide and 98% for other VOC compounds. This flare utilizes a continuous pilot which is fueled with natural gas to ensure that unexpected release events result in safe disposal. GHG emissions, primarily CO_2, are generated from combustion of natural gas used to maintain the flare pilots. Table 3 shows estimated flare GHG emission.

Table 3. Estimated Flare GHG Emissions				
Combusted Material	**Pollutant**	**Emissions (tpy)**	**GWP [1]**	**CO_2e (tpy)**
Natural Gas and VOC Vapors	CO_2	576	1	577
	CH_4	0.024	25	
	N_2O	0.0038	298	

1 GWP factors from 40 CFR 98, Table A-1.

3. **Emergency Diesel-Powered Engines (EPNs: FWP1, FWP2, EMGEN1 and EMGEN2)**

Magellan will equip the site with four diesel-powered emergency engines. Emergency engines (EMGEN1 and EMGEN2) with a rating of 500kW and 100kW, respectively, will be used to supply electrical power for control systems in the event of power outage. Meanwhile, the other two diesel-powered emergency engines (FWP1 and FWP2) are nominally rated 617-hp. They will be used to power a firewater pump in the event of a fire. Each of the emergency engines will be limited to 100 hours per year of non-emergency operation for purposes of maintenance checks and readiness testing.

Table 4 shows the potential emissions of the firewater pump engine and the emergency generator, respectively. These estimates were based on the 100 hours of testing/maintenance, non-emergency use, and emission factors from EPA's "Compilation of Air Pollutant Emission Factors," commonly referred to as AP-42.

<table>
<tr><th colspan="5">Table 4. Estimated Emergency Engine GHG Emissions</th></tr>
<tr><th>Source</th><th>Pollutant</th><th>Emissions (tpy)</th><th>GWP [1]</th><th>CO_2e (tpy)</th></tr>
<tr><td rowspan="3">Fire Water Pump (FWP1)</td><td>CO_2</td><td>32</td><td>1</td><td rowspan="3">32</td></tr>
<tr><td>CH_4</td><td>0.001</td><td>25</td></tr>
<tr><td>N_2O</td><td>0.0002</td><td>298</td></tr>
<tr><td rowspan="3">Backup Fire Water Pump (FWP2)</td><td>CO_2</td><td>32</td><td>1</td><td rowspan="3">32</td></tr>
<tr><td>CH_4</td><td>0.001</td><td>25</td></tr>
<tr><td>N_2O</td><td>0.0002</td><td>298</td></tr>
<tr><td rowspan="3">Emergency Generator 1 (EMGEN1)</td><td>CO_2</td><td>39</td><td>1</td><td rowspan="3">39</td></tr>
<tr><td>CH_4</td><td>0.001</td><td>25</td></tr>
<tr><td>N_2O</td><td>0.0003</td><td>298</td></tr>
<tr><td rowspan="3">Emergency Generator 2 (EMGEN2)</td><td>CO_2</td><td>8</td><td>1</td><td rowspan="3">8</td></tr>
<tr><td>CH_4</td><td>0.0003</td><td>25</td></tr>
<tr><td>N_2O</td><td>0.00006</td><td>298</td></tr>
</table>

1 GWP factors from 40 CFR 98, Table A-1.

4. **Vapor Combustion Unit (EPN: MSSVCU)**

Magellan will install a new Vapor Combustion Unit (VCU) to control vapors from various maintenance, startup, and shutdown (MSS) activities at the proposed condensate splitter plant, including internal floating roof tank landings, purging of pressure tanks, and the wastewater treatment system vents. GHG emissions, primarily CO_2, are generated from assist natural gas used to maintain the required minimum combustion chamber temperature to achieve adequate destruction and the combustion of VOC vapors associated with the loading of products and MSS activities. The estimated GHG emissions from the new VCU are included in Table 5.

Table 5. Estimated GHG Emissions –VCU				
Sources	**Pollutant**	**Emissions (tpy)**	**GWP [1]**	**CO_2e (tpy)**
MSSVCU	CO_2	2,645	1	2,648
	CH_4	0.056	25	
	N_2O	0.0072	298	

1 GWP factors from 40 CFR 98, Table A-1.

5. Natural Gas Piping Fugitives (EPN: FUG-1)

The proposed condensate splitter plant will contain process piping components which include valves, flanges, pump seals, etc. Fugitive emissions of GHG pollutants, including methane, may result from piping equipment leaks. Magellan estimated fugitive GHG emissions based on methods provided in the TCEQ's *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000*. These estimates are provided in Table 6.

Table 6. Estimated Fugitive GHG Emissions			
Component Type	**Annual CH_4 Emissions (tpy)[1]**	**GWP for CH_4**	**CO_2e Emissions (tpy)**
Valves/pumps/Flanges	6.42	25	160

[1] Assumption that piping component fugitive emissions are consisted of 100% CH_4 for GHG PSD applicability purposes.

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.

Applicable Emission Units and BACT Discussion

The majority of the contribution of GHGs associated with the project is from combustion sources (i.e., heaters, flare, vapor combustion units, etc.) Stationary combustion sources primarily emit CO_2, and small amounts of N_2O and CH_4. The following devices are subject to this GHG PSD permit:

- Heaters (EPNs: H-1A, H-2A, H-1B, H-2B, and H-4)
- Flare (EPN: FL-1)
- Diesel-Powered Emergency Engines (EPNs: FWP1, FWP2, EMGEN1, and EMGEN2)
- Vapor Combustion Unit (EPN: MSSVCU)
- Fugitives (EPN: FUG1)

1. Heaters (EPNs: H-1A, H-2A, H-1B, and H-2B)

Magellan will use natural gas/fuel gas-fired combustion heaters as part of the proposed condensate splitter process. These proposed natural gas/fuel gas-fired combustion heaters will generate GHG emissions, primarily CO_2. The proposed condensate splitter plant will utilize two hot oil heaters (each has a maximum and annual average firing rates of 105.8 MMBtu/hr and 96.2 MMBtu/hr, respectively), and two fractionator heaters (each has a maximum and annual average firing rates of 128.9 MMBtu/hr and 117.2 MMBtu/hr, respectively). As part of the PSD review, Magellan provided a 5-step top-down BACT analysis for the heaters. EPA has reviewed Magellan's BACT analysis for the heaters, which has been incorporated into this SOB, and provides its own analysis in setting forth BACT for this proposed permit, as summarized below.

1) Step 1 – Identify All Available Control Technologies

- *Use 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. The use of fuels with low carbon intensity and high heat intensity is appropriate BACT for GHG. The use of natural gas and fuel gas as fuel meet these criteria.

- *Carbon Capture and Sequestration (CCS)* – CCS is classified as an add-on pollution control technology that involves the separation and capture of CO_2 from flue gas, pressurizing of the captured CO_2 into a pipeline for transport, and injection/storage within a geologic formation. It is available for use by large CO_2 emitting facilities such as fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, etc.)[3]

CCS contains three major components: carbon capture, transport and storage. With respect to carbon capture, CCS systems use 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 suitable 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 this type of applications. Accordingly, pre-combustion capture and oxyfuel combustion are not considered available control options for this proposed facility. The third approach, post-combustion capture, is applicable to heaters.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Many of these methods are either still in development or are not suitable for treating heater exhaust gas due to the characteristics of the exhaust stream (Wang, 2011; IPCC, 2005).

In applications where CO_2 has been captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres or higher for ease of transport (usually by pipeline). The CO_2 may then be transported to an appropriate location for underground injection if a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, is available 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.

- *Heater Design* – The heaters will be designed to use efficient burners; efficient heat transfer/recovery efficiency; and state-of-the-art refractory and insulation materials in the heater walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency.

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[3] U.S. EPA, Office of Air Quality Planning and Standards, PSD and Title V Permitting Guidance for Greenhouse Gases. March 2011. Available at: http://www.epa.gov/nsr/ghgdocs/ghgpermttingguidance.pdf.

- *Heater Air/Fuel Control* –Monitoring of oxygen concentration in the flue gas to be used to control air to fuel ratio on a continuous basis for optimal efficiency.

- *Periodic Heater Tune-ups* – Periodically tune-up the heaters to maintain optimal thermal efficiency.

- *Waste Heat Recovery* – Use of heat recovery from both the heater exhausts and process streams to preheat the heater combustion air, feed (oil) to heaters, or to produce steam for use at the site.

- *Product Heat Recovery* – Hot product streams are cooled with exchange of heat with the colder feed and the distillation column's stripping section to provide process heat in lieu of heat from the furnace.

2) Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible, with the exception of waste heat recovery. Magellan indicated that waste heat recovery is not practical alternative for the proposed heaters. Specifically, the hot oil heaters are designed to maximize heat transfer to the oil medium with a resulting low exhaust gas temperature (<400°F) that does not contain sufficient residual heat to allow any further effective heat recovery. Use of flue gas heat recovery to preheat the heater combustion air is typically only considered practical if the exhaust gas temperature is higher than 650°F (*Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry:* An ENERGY STAR Guide for Energy Plant Managers (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008)). EPA agrees with Magellan's analysis to reject waste heat recovery from this BACT review based on technical feasibility concerns.

Magellan raised concerns with the technical feasibility of using CCS for controlling GHG emissions from a natural gas-fired facility. As indicated, the proposed facility is not a facility type which emits CO_2 in large amounts nor has high-purity CO_2 streams for which CCS should be considered. CCS technology has been proposed for some recent gasification projects. In these processes, when coal is gasified, the product is a mixture consisting primarily of CO, CO_2, and H_2. Further processing of the raw syngas to produce a final fuel product typically results in a concentrated CO_2 waste stream that is naturally ready for sequestration. Combustion of natural gas or ethane, as is proposed by Magellan, produces an exhaust stream that is less than 10% CO_2. Separation (purification) of the CO_2 from the heater combustion exhaust streams would require additional costly steps not otherwise necessary to the process. Coal also has a much higher carbon content than natural gas, and the captured carbon from coal gasification projects only represents the delta between natural gas and coal. Thus, while such projects may reduce GHG emissions compared to conventional methods of obtaining energy from coal, they result in no GHG emissions reduction relative to use of natural gas fuel as proposed for the process heaters.

However, Magellan included this control option in the remainder of the analysis and provided a basis for why it is not economically viable in the Step 4 of the BACT analysis.

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

- Use of low carbon fuels (up to 100% GHG emission reduction for fuels containing no carbon);
- CO_2 capture and storage (up to 90% GHG emission reduction);
- Heater/process design (up to 10% GHG emission reduction);
- Good combustion practices (5 to 25% GHG emission reduction);
- Periodic tune-up (up to 10% GHG emission reduction, no information for heaters); and,
- Product heat recovery (does not directly improve heater efficiency).[4]

Generally, all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel to CO_2. Thus, use of a completely carbon-free fuel such as 100% hydrogen has the potential of reducing CO_2 emissions by 100%. However, hydrogen is not produced from the processes at the Magellan's Corpus Christi Terminal, nor is it otherwise readily available as a fuel at this facility, so it is not an available option. Natural gas is the lowest carbon fuel available at the terminal.

CO_2 capture and storage is capable of achieving 90% reduction of produced CO_2 emissions and thus is considered to be the most effective control method. Good heater design, air/fuel ratio control, and periodic tune-ups are all considered effective and have a range of efficiency improvements that cannot be directly quantified; therefore, the above ranking is approximate only.

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

[4] The estimated control efficiencies are derived from *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry*: An ENERGY STAR Guide for Energy and Plant Managers (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008).

a. Use of Low Carbon (Natural Gas) Fuel

As explained above, natural gas is the lowest carbon fuel available for use in the proposed heaters. Natural gas is readily available at the Magellan's Corpus Christi Terminal and is considered a very cost effective fuel alternative. Natural gas is a very clean burning fuel with respect to criteria pollutants and thus has minimal environmental impact compared to other fuels. The use of produced off-gas stream as supplemental fuel gas for heaters will minimize the use of purchased natural gas usage and lower the overall site carbon footprint.

b. Carbon Capture and Sequestration

Magellan developed a cost analysis that provided a basis for eliminating CCS in Step 4 of the BACT analysis based on economic costs and environmental impacts. Magellan contends that the recovery and purification of CO_2 from the stack gases would necessitate significant additional processing, including energy and environmental/air quality penalties, to achieve the necessary CO_2 concentration for effective sequestration. The operation of the additional process equipment required to separate, cool, and compress the CO_2, would require a significant additional power expenditure.

Magellan also developed and submitted a site-specific cost analysis for CCS as part of the application. Magellan estimated the cost of CCS for the project would be approximately $113 per ton of CO_2 controlled. The majority of the estimated cost is attributable to the capture and compression facilities that would be required. Magellan estimated the capital cost of the equipment required for CCS for this project is estimated approximately $177,000,000 and the cost of the project without CCS to be $400,000,000. EPA Region 6 reviewed Magellan's CCS cost estimate and believes it adequately approximates the cost of a CCS control for this project and demonstrates those costs would increase the capital cost of the project by 44%. EPA believes that these costs are excessive in relation to the overall cost of the proposed project without CCS. In addition, the annualized cost of CCS is more than half of the annualized capital cost of the project alone without CCS.

In addition, there is a potential for negative environmental and energy impacts associated with the use of CCS for the proposed heaters. Specifically, operation of the additional process equipment required to separate, cool, and compress the CO_2 would require additional power. This equipment includes amine units, cryogenic units, dehydration units, and compression facilities. The required energy would most likely be provided from additional combustion units, including heaters, engines, and/or combustion turbines. Electric driven compressors could be used to partially eliminate the additional emissions from the terminal itself, but significant additional GHG emissions, as well as additional criteria pollutant (NOx, CO, VOC, PM, SO_2) emissions, would occur from the associated power plant that produces the electricity. The additional GHG emissions resulting from additional fuel combustion would either further increase the cost of the CCS system if the emissions were also captured for sequestration or, if not captured, reduce the net amount of GHG emission reduction, making CCS even less cost effective than what was shown in Magellan's cost analysis.

In light of the estimated capital and annualized operational costs of CCS control for the volume of CO_2 from this project, the estimated costs are excessive in relation to costs of the proposed project. EPA has determined that CCS should be eliminated as BACT for this facility.

c. Heater Design

New heaters will be designed with efficient burners, greater heat transfer efficiency, state-of-the-art refractory and insulation materials in the heater walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency. In addition, the process includes multiple heat exchangers which reduce the heating and cooling requirements of the process leading to improved thermal efficiency. The function and near steady state operation of the hot oil heaters allows them to be designed to achieve "near best" thermal efficiency. There are no negative environmental, economic, or energy impacts associated with this control technology.

d. Heater Air/Fuel Control

Some amount of excess air is required to ensure complete fuel combustion, minimize emissions, and enhance safety; however, too much excess air can also reduce overall heater efficiency. Good fuel/air mixing in the combustion zone will be achieved through the use of oxygen monitors and intake air flow monitors to optimize the fuel/air mixture and limit excess air. Manual or automated air/fuel ratio controls are used to optimize these parameters and maximize the efficiency of the combustion process. Limiting the excess air enhances efficiency and reduces emissions through reduction of the volume of air that needs to be heated in the combustion process. Magellan will monitor exhaust temperature and O_2 content, and adjust the air/fuel using fans and a bypass damper on the air preheat exchanger to maintain heater efficiency to the maximum extent practical during actual operation. In addition, proper fuel gas supply system design and operation to minimize fluctuations in fuel gas quality, maintaining sufficient residence time to complete combustion, and good burner maintenance and operation are part of Magellan's good combustion practices. There are no negative environmental, economic, or energy impacts associated with this control technology.

e. Periodic Heater Tune-ups

Periodic tune-ups of the heaters include:

- Preventative maintenance check of fuel gas flow meters annually,
- Preventative maintenance check of oxygen control analyzers quarterly,
- Cleaning of burner tips on an as-needed basis, and
- Cleaning of convection section tubes on an as-needed basis.

These activities insure that maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement, although convection cleaning has shown improvements in the 0.5 to 1.5% range, and routine and proper maintenance can theoretically recover up to 10% of the efficiency lost over time to age and wear. There are no negative environmental, economic, or energy impacts associated with this control technology.

f. Product Heat Recovery

Rather than increasing heater efficiency, this technology reduces potential GHG emissions by reducing the required heater duty (fuel firing rate), which can substantially reduce overall plant energy requirements. Excess heat in product streams will be used to pre-heat feed streams throughout the process through the use of heat exchangers to transfer the heat from the product stream to the feed stream. This will also reduce the energy requirement (primarily purchased electricity) needed to cool the product streams. There are no negative environmental, economic, or energy impacts associated with this control technology.

5) Step 5 – Selection of BACT

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

Company/Location	Process Description	BACT Control(s)	BACT Emission Limit/ Requirements	Year Issued	Reference
Enterprise Products Operating LLC, Eagleford Fractionation Mont Belvieu, TX	NGL Fractionation 2 Hot Oil Heaters (140 MMBtu/hr each) 2 Regenerant Heaters (28.5 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 Regenerant heaters only have good combustion practices	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 – 2759 lb CO_2/bbl of NGL processes 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
KM Liquids Terminals LLC, Galena Park , TX	Condensate Splitter Plant 2 Natural Gas 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. KM Liquids Terminals is a condensate splitter plant that has similar process like the one proposed by Magellan. Magellan has proposed to monitor thermal efficiency of the heaters. They have proposed to maintain an 85% thermal efficiency, which is the same as the one that was proposed by KM Liquids for their hot oil heaters. The KM Liquids oil heaters are rated at 247 MMBtu/hr, and the Magellan hot oil heaters and fractionator heaters have a maximum firing rate of 105.8 MMBtu/hr and 128.9 MMBtu/hr, respectively. EPA analyzed the proposed BACT and determined that it is consistent with, and at least as stringent as, other BACT determinations for similar units.

The following specific BACT practices are proposed by Magellan for the heaters:

- *Use of Low Carbon (Natural Gas) Fuel* – Pipeline quality natural gas will be the only purchased fuel fired in the proposed heaters. It is the lowest carbon purchased fuel available.
- *Heater Design* – The heaters shall be designed to maximize heat transfer efficiency and reduce heat loss.
- *Air to Fuel Ratio Control* – Magellan will install, utilize, and maintain an automated air/fuel control system to maximize combustion efficiency in the heaters. The heaters will maintain a minimum thermal efficiency of 85%.
- *Periodic Heater Tune-ups* – Maintain analyzers and clean burner tips and convection tubes as needed, but no less frequently than every 12 months.
- *Product Heat Recovery* – Excess heat in product streams will be used to pre-heat feed streams throughout the process through the use of heat exchangers to transfer the heat from the product stream to the feed stream.

BACT Limits and Compliance:

Magellan shall demonstrate compliance with an 85% thermal efficiency on each heater on a 12-month rolling average basis. The heaters will be continuously monitored for exhaust temperature, fuel temperature, ambient temperature, and stack O_2 concentration. Thermal efficiency will be calculated for each operating hour from these continuously monitored parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4th ed.) Annex G. To ensure compliance with the proposed emission limit, Magellan shall not exceed annual average firing rates of 96.2 MMBtu/hr and 117.2 MMBtu/hr for each of the hot oil heaters and fractionator heaters, respectively. Efficient heater design and good combustion practices of the heaters corresponds to emission limits of 60,111 tpy CO_2e and 49,340 tpy CO_2e for each of the fractionator heaters and oil heaters, respectively. The heaters will be designed to incorporate efficiency features, including insulation to minimize heat loss and heat transfer components that maximize heat recovery in order to minimize exogenous fuel use. Magellan will maintain records of heater tune-ups, burner tip maintenance, O_2 analyzer calibrations and maintenance for all heaters. In addition, Magellan will maintain records of fuel temperature, ambient temperature, and stack exhaust temperature for the heaters. Magellan will demonstrate compliance with the CO_2 limits for the heaters using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-2. The equation for estimating CO_2 emissions as specified in 40 CFR § 98.33(a)(3)(iii) is as follows:

$$CO_2 = (44/12) * (Fuel) * (CC) * (MW/MVC) * (0.001) * (1.102311)$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to 40 CFR § 98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at 40 CFR § 98.33(a)(2)(ii).
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at 40 CFR § 98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in 40 CFR § 98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons

The proposed permit also includes an alternative compliance demonstration method, in which Magellan 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 GHG emissions from the heaters; 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. 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 0.1% 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.

2. Tank Heater (H-4)

Magellan will use one existing non-modified and one new natural gas-fired tank heater, as needed, to provide heat to storage tanks and dock lines at the facility. The new tank heater (H-4) is a small natural gas-fired heater which has an annual average firing rate of 16 MMBtu/hr. It and the existing tank heater do not run continuously and are only anticipated to be needed approximately 4,380 hours annually. The emission of the tank heater constitutes less than 2% of the total project GHG emissions.

1) Step 1 – Identification of Potential Control Technologies

- *Fuel Selection* – 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. Selecting fuels with low carbon intensity and high heat intensity is appropriate BACT for GHG.
- *Limited operation to minimize emissions*.
- *Carbon Capture and Sequestration (CCS)* – CCS is classified as an add-on pollution control technology that involves the separation and capture of CO_2 from flue gas, pressurizing of the captured CO_2 into a pipeline for transport, and injection/storage within a geologic formation. It is available for use by large CO_2 emitting facilities such as fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, etc.).[5]
- *Heater/Process Design* – The heater will be designed to use efficient burners; efficient heat transfer/recovery efficiency; and state-of-the-art refractory and insulation materials in the heater walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency.
- *Good Combustion Practices* – Good fuel/air mixing in the combustion zone through use of oxygen monitors to optimize the fuel/air mixture and limit excess air. The formation of GHGs can be controlled by proper operation and using good combustion techniques.
- *Periodic Burner Tune-up* – Periodically tune-up the heater to maintain optimal thermal efficiency.
- *Waste Heat Recovery* – Use of heat recovery from the heater exhaust and process streams to preheat the heater combustion air, heaters fuel feeding streams, or to produce steam for use at the site.

2) Step 2 – Elimination of Technically Infeasible Alternatives

Due to the small size, intermittent operation, and minimal GHG emissions from the tank heater, CCS and waste heat recovery are considered technically infeasible for this heater due to the intermittent operation. The tank heater cannot be used effectively for waste heat recovery, as it is a small on/off cycled heater.

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

[5] U.S. EPA, Office of Air Quality Planning and Standards, PSD and Title V Permitting Guidance for Greenhouse Gases. March 2011. Available at: http://www.epa.gov/nsr/ghgdocs/ghgpermttingguidance.pdf.

- Use of low carbon fuels (up to 100% GHG emission reduction for fuels containing no carbon);
- Limit operation (50% reduction based on 6 months per year of operation);
- Heater/process design (up to 10% GHG emission reduction);
- Air/fuel Control (5 - 10% GHG emission reduction); and
- Periodic tune-up (negligible for these heaters).

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

Magellan indicated that all options in Step 3 are typically used to varying degrees to improve efficiency and minimize GHG emissions from the heater.

5) Step 5 – Selection of BACT

Magellan proposes to use efficient heater design, use of natural gas, and periodic tune-ups as BACT for the heater. The following specific BACT practices are proposed for the new tank heater to minimize GHG emissions:

- Use of low carbon fuel (natural gas) as the only fuel,
- Limit operation to 4,380 hours per year,
- Efficient heater design,
- Air to fuel ratio control, and
- Periodic tune-ups as required by the manufacturer.

To ensure compliance with the proposed emission limit, Magellan shall not exceed annual average and maximum firing rates of 16 MMBtu/hr. Efficient heater design and good combustion practices of the heaters corresponds to an emission limit of 4,103 tpy CO_2e for the new tank heater. Compliance with this limit will be determined by calculating the emissions on a daily basis, and keeping a rolling total of hours of operation.

3. Flare (EPN: FL-1)

The new condensate splitter plant will utilize a flare for emergency overpressure situations to dispose of excess process vapors. The flare controls routine process streams and purged vapors from miscellaneous vessels and piping and during refilling of the equipment. The routine streams to the flare include pilot gas, purge gas and intermittent flow associated with the vapor control on the Feed Surge Drum. The flare's pilots are fueled by pipeline quality natural gas. The flare will have a 99% destruction and removal efficiency (DRE) of compounds containing no more than 3 carbons that contain no elements other than carbon and hydrogen in addition to the following compounds: methanol, ethanol, propanol, ethylene oxide, and propylene oxide. For other VOC compounds, the flare DRE is 98%. The flare GHG emissions, primarily CO_2, are from the combustion of waste gas streams and pilot/assist natural gas used to maintain the required minimum heating value to achieve adequate destruction.

1) Step 1 – Identification of Potential Control Technologies

- *Thermal Oxidizer/Vapor Combustion Unit (VCU) in lieu of a flare* – Alternate control technology consideration.
- *Vapor Recovery Unit (VRU) in lieu of a flare* – Alternate control technology consideration.
- *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* – Equip the flare with continuous pilot flame monitoring and a thermocouple on the flare stack. The flare purge rate will be determined by the manufacturer. Visual opacity monitoring will occur when the flare is operating.

2) Step 2 – Elimination of Technically Infeasible Alternatives

Two of the options identified in Step 1 are not considered technically feasible, VCU and VRU. One of the primary reasons that a flare is considered for control of VOC in the process vent streams is that it can also be used for emergency releases. Both VRU and VCU would not be capable of handling the sudden large volumes of vapor that could occur during an upset release. A thermal oxidizer/VCU would also not result in a significant difference in GHG emissions compared to a flare. For this reason, even if a VCU or a VRU were used to control routine vent streams, the flare would still be necessary and would require continuous burning of natural gas in the pilots, which add additional CO_2, NOx, and CO emissions.

The flare will largely handle upset/emergency releases, intermittent MSS and process emissions. These emissions are rare and generally of short duration. Given these conditions, vapor combustion and vapor recovery of high volumes and short durations is infeasible to implement.

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

- Flaring minimization (up to 100% GHG emission reduction depending on activity type)
- Proper operation of the flare (not directly quantifiable)

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel (i.e., the natural gas needed to power the flare) and/or waste gas to CO_2. Magellan will design the proposed condensate splitter plant in a way that will minimize the volume of the waste gas sent to the flare. For instance, gas flow to the flare will be limited to pilot and purge gas only during routine operation. To the extent possible, flaring will be limited to purge/pilot gas, emission events, and purged vapors from miscellaneous vessels and piping and during refilling of the equipment.

Proper operation of the flare results in a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only, and in any case, both of these control technologies are part of the BACT limit. Use of an analyzer to determine the heating value of the flare gas to allow continuous determination of the amount of natural gas needed to maintain a minimum heating value of 300 Btu/scf to ensure proper destruction of VOCs ensures that excess natural gas is not unnecessarily flared.

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

a. Flaring Minimization

Magellan will design the proposed condensate splitter plant in a way that will minimize the volume of the waste gas sent to the flare. During routine operation, gas flow to the flare will be limited to pilot and purge gas only. Process/waste gases from the proposed condensate splitter plant will be recycled back to the heaters as heat input (i.e., approximately 6% of the combined firing capacity of the heaters) thus reducing the amount of natural gas heat input. Magellan will reduce MSS purged vapor emissions to flare by minimizing vapor space volume, limiting the duration of MSS activities, and clearing equipment to storage as possible to minimize the quantity of the VOC materials vented to the flare during the MSS activities. There are no negative environmental, economic, or energy impacts associated with this control technology.

b. Proper Operation of the Flare

Magellan will equip the process flare with continuous flame monitoring and the flare stack with a thermocouple. To ensure proper destruction of VOCs and that excess natural gas is not necessarily flared, Magellan will also adjust the amount of assist natural gas needed for proper operation of the flare. 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, economic, or energy impacts associated with this control technology.

5) Step 5 – Selection of BACT

The following specific BACT practices are proposed for the process flare:

- *Flaring Minimization*– Minimize the duration and quantity of flaring to the extent possible through good engineering design of the process and good operating practice.
- *Proper Operation of the Flare* – The formation of GHGs can be controlled by proper operation and using good combustion practices. Poor flare combustion efficiencies lead to higher methane emissions and higher overall GHG emissions. Magellan will equip the process flare with continuous pilot flame monitoring and the process flare stack with a thermocouple. Periodic maintenance will help maintain the efficiency of the flare.

EPA has reviewed and concurs with Magellan that minimization of waste gas along with the use of good flare design and best operational and maintenance practices are BACT. Therefore, Magellan shall design, build operate and maintain their flare system (FL-1) in accordance with 40 CFR § 60.18. This will ensure the flare system achieves at least a 98% DRE for VOCs and a 99% DRE for methane. Included within this practice, Magellan shall:

- Continuously monitor and record the pressure of the flare system header;
- Continuously monitor and record the waste gas flow at the flare headers;
- Continuously monitor and meter supplemental natural gas to maintain a minimum heating value, consistent with 40 CFR § 60.18, routed to the flare system to ensure the intermittent stream is combustible and necessary for flame stability; and
- Continuously monitor for the presence of a pilot flame with a thermocouple or other approved device.

4. Process Fugitives (EPN: FUG-1)

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. Fugitive emissions of methane contribute a small amount to the total project GHG emissions.

1) Step 1 – Identification of Potential Control Technologies

- *Leak-less Technology components* - The use of leak-less components, i.e., welded connections and fittings, would eliminate the potential for GHG emissions from process and fuel-gas fugitives. Leak-less technology is an expensive design option usually reserved for toxic and hazardous gases.

- *Instrument-based Leak Detection and Repair (LDAR) program* - The use of a portable organic vapor detector meeting the specifications and performance criteria specified in 40 CFR Part 60, Appendix A, Test Method 21 to monitor piping components for leaks and repair them when found would result in decreased potential for GHG emissions from the project. The LDAR program would conform to the TCEQ 28VHP program.

- *Audio, visual, olfactory (AVO) LDAR program*

2) Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are technically feasible options for controlling process fugitive GHG emissions.

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

Leak-less Technology is the most effective control. By installing leak/seal free valves and piping systems, the facility could achieve close to 100% effectiveness in eliminating fugitive emissions from specific interface where installed. However, leak interfaces remain even with leak-less technology components in place. In addition, the sealing mechanism, such as a bellows, is not repairable online and may leak in the event of a failure until the next unit shutdown. Because of their high cost, these specialty components are, in practice, selectively applied only as absolutely necessary to toxic or hazardous components.

LDAR programs could control GHG fugitive emissions by 75% or more; however, they 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 methane emissions. Monitors typically used for Method 21 instrument monitoring cannot detect CO_2 leaks. Instrumented monitoring can identify leaking CH_4, making possible the identification of components requiring repair. Method 21 instrument monitoring has historically been used to identify leaks in need of repair.

Remote sensing using an infrared imaging has proven effective for identification of leaks, especially on larger pipeline-sized lines and for components in difficult to monitor areas. Instrument LDAR programs and the alternative work practice of remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[6] Although, remote sensing using infrared imaging has been accepted by EPA as an acceptable alternative to Method 21 instrument monitoring and leak detection effectiveness is expected to be comparable, it has not been quantified.

An AVO LDAR program could control GHG fugitive emissions by 75% or more. AVO monitoring is effective due to the frequency of observation opportunities, but it is not very effective for low leak rates. It is not preferred for identifying large leaks of odorless gases such as methane. However, since pipeline natural gas is odorized with very small quantities of mercaptan, AVO observation is a very effective method for identifying and correcting leaks in natural gas systems. Due to the pressure and other physical properties of plant fuel gas, AVO observations of potential fugitive leaks are likewise moderately effective.

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

The use of leak-less components, instrument LDAR and/or remote sensing of piping fugitive emission in natural gas service may be somewhat more effective than the AVO LDAR programs, but the incremental GHG emissions controlled by implementation of the TCEQ 28LAER LDAR program or a comparable remote sensing program is considered a *de minimis* level in comparison to the total project's proposed CO_2e emissions. Given that GHG fugitives are conservatively estimated to comprise approximately 0.07% CO_2e emissions from the facility, there is, in any case, a negligible difference in emissions between the considered control alternatives. Accordingly, given the costs of installing leak-less technology components (which is estimated to be 3 to 10 times higher than comparable high quality valves) or implementing 28LAER or a comparable remote sensing program when not otherwise required, these methods are not economically practicable for GHG control from components in natural gas service. AVO monitoring is expected to be effective in finding leaks and can be implemented at the greatest frequency and lowest cost due to being incorporated into routine operations.

5) Step 5 – Selection of BACT

[6] 73 FR 78199-78219 (December 22, 2008).

Magellan proposes to use high engineering standards for the selection of equipment and implementing an AVO LDAR program by plant personnel as BACT for fugitive emissions control associated with this project.

For the GHG fugitive emission sources in this plant, Magellan is proposing:

- To implement an AVO LDAR program for natural gas piping components:
  - To perform the AVO monitoring on a daily basis; and
  - To maintain a written log of daily inspections identifying the operating area inspected, the date inspected, the fuel gas and natural gas equipment inspected (valves, lines, flanges, etc), whether any leaks were identified by visual, audio or olfactory inspections, and corrective actions/repairs taken.
- For leaks identified, immediately upon detection of the leak, plant personnel will take the following action:
  - Tag the leaking equipment; and
  - Commence repair or replacement of the leaking component as soon as practicable, but no later than 30 days after detection.

EPA concurs with Magellan's proposal of implementing an AVO LDAR program for detecting leaks in natural gas piping components and fugitive emissions of methane. EPA proposes the implementation of such AVO LDAR program for fugitive emissions control for process lines not in VOC service but containing methane. For process lines in VOC service, Magellan will implement TCEQ 28VHP LDAR program under the permit issued by TCEQ for non-GHG pollutants. The TCEQ 28LDAR programs would not normally be considered for control of GHG emissions alone due to the negligible amount of GHG emissions from fugitive sources. However, the LDAR program is being imposed in this instance. It is imposed as a work practice. (See 40 CFR § 51.166(b)(12))

Because GHG emissions associated with leaks are difficult to quantify, the proposed permit contains no numerical BACT limitation for fugitives from equipment leaks. Magellan will be required to implement an LDAR program that is compliant with TCEQ 28VHP for process lines in VOC service. The leak thresholds, and repair requirements, and record keeping requirements shall be consistent with the TCEQ air permit requirements for VOC emissions.

5. Maintenance, Startup, and Shutdown Vapor Combustion Unit (EPN: MSSVCU)

Magellan will also install a new Vapor Combustion Unit (VCU) to control vapors from various maintenance, startup, and shutdown (MSS) activities at the proposed condensate splitter plant, including internal floating roof tank landings, and purging of pressure tanks. If the material stored in the tanks has vapor pressure greater than 0.5 psia, the VCU will be used to control the emissions when the tanks are degassed for maintenance purposes. GHG emissions, primarily CO_2, are generated from assist natural gas used to maintain the required minimum combustion chamber temperature to achieve adequate destruction and the combustion of VOC vapors associated with MSS activities.

1) Step 1 – Identification of Potential Control Technologies

The only viable control option for reducing GHG emissions is minimizing the quantity of combusted VOC vapors and assist natural gas to the extent possible. The available control technologies are:

- *Use of a Vapor Recovery Unit (VRU) in Lieu of a flare/VCU* – VRU systems (i.e., carbon canister, scrubber, etc.) do not generate GHG emissions. They can be utilized to control MSS emissions associated with vacuum trucks, frac tanks, and other process area equipment that are not connected to the flare or portable VCU.
- *Minimization* – Minimize the duration and quantity of combustion to the extent possible through good engineering design of the process and good operating practices.
- *Proper Operation of VCU* – Use of a temperature monitor to accurately determine the optimum amount of natural gas required to ensure adequate VOC destruction in order to minimize natural gas combustion and the resulting CO_2 emissions. Use of an analyzer(s) to determine the VCU combustion chamber temperature allows for the continuous determination of the amount of natural gas needed to maintain the combustion chamber temperature above 1,400^{o}F. Maintaining the combustion chamber above 1,400^{o}F allows for the proper destruction of VOCs and ensures that excess natural gas is not unnecessarily combusted.

2) Step 2 – Elimination of Technically Infeasible Alternatives

All options in Step 1 are technically feasible. Vacuum trucks, frac tanks (portable tanks), and other process area equipment not connected to the flare will utilize VRU technology (i.e., carbon canister, scrubber, etc.) for MSS emissions control. VRU usage is limited to MSS activities where the flow rate and event duration warrant its use. Specifically, a VRU is not capable of handling the sudden large volumes of vapor that could occur during unit turnarounds or storage tank roof landing activities.

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

The technologies applicable to the proposed design in order of most effective to least effective include *the use of a VRU in lieu of a VCU* (up to 100% GHG emission reduction), m*inimization* (not directly quantifiable for MSS activities), and *proper operation of a VCU* (not directly quantifiable for MSS activities).

Proper operation of the VCUs results in a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only.

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

a. Minimization

New storage tanks and process equipment are designed such that the vapor space volume requiring control during MSS activities is significantly reduced. Specifically, VOC emissions and the subsequent GHG emissions associated with MSS activities are significantly reduced by limiting the duration of MSS activities, reducing vapor space volume requiring control, painting tanks white, incorporating "drain dry" sumps into the tank design, draining residual VOC material to closed systems, etc. There are no negative environmental, economic, or energy impacts associated with this control technology.

b. Proper Operation

VCU typically achieves higher DREs (i.e., 99%) than flares (i.e., 98%); therefore, VCU is often utilized to control loading emissions to achieve emission limits reflecting LAER. The use of a flare would not result in a significant difference in GHG emissions compared to a thermal oxidizer/VCU. However, use of a flare would result in higher VOC emissions with no significant difference in GHG emissions. Use of analyzer(s) is to ensure the VCU combustion chamber temperature maintaining above 1,400^{o}F or the most recent stack test temperature in accordance with Special Condition Number 16 of the TCEQ NSR permit No. 56470. Temperature will be measured and recorded with 6 minute averaging periods as required by the NSR permit. Maintaining the VCU combustion chamber temperature at the proper temperature for the destruction of VOCs ensures that excess natural gas is not unnecessarily combusted. 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, economic, or energy impacts associated with this control technology.

a. Step 5 – Selection of BACT

The following specific BACT practices are proposed for marine vapor combustion units:

- *Use of a VRU in lieu of a Flare/VCU for control MSS emissions* – VRU systems (i.e., carbon canisters, scrubbers, etc.) will be utilized to control MSS emissions associated with vacuum trucks, frac tanks, and any equipment that is not connected to the flare in the process area or portable VCU.
- *Minimization*– Minimize the duration and quantity of combustion to the extent possible through good engineering design of the storage tanks and process equipment and good operating practice.
- *Proper Operation of the VCU* – Magellan will monitor the combustion chamber temperature above 1400°F or the most recent stack test temperature in accordance with Special Condition 16 of the TCEQ NSR permit No. 56470 to ensure adequate destruction of VOCs and to minimize natural gas combustion and resulting CO_2 emissions.

Using these best operating practices above will result in the minimization of MSS emissions. The emissions from MSSVCU is estimated to be 2,648 tpy CO_2e. Compliance will be demonstrated based on the minimum combustion chamber temperature on a 6 minute average temperature above the one hour average temperature maintained in the initial stack test, which will be 1,400° F at a minimum. The stack test shall be repeated, when a process change is made, to ensure proper VCU operation and efficiency. Magellan will demonstrate compliance with the CO_2 emission limit using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1, and the site specific fuel analysis for process fuel gas. The equation for estimating CO_2 emissions as specified in 40 CFR § 98.33(a)(3)(iii) is as follows:

$$CO_2 = (44/12) * (Fuel) * (CC) * (MW/MVC) * (0.001) * (1.102311)$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of loading vapor and 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 40 CFR § 98.3(i).

CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at 40 CFR § 98.33(a)(2)(ii).

MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at 40 CFR § 98.33(a)(2)(ii).

MVC = Molar volume conversion factor at standard conditions, as defined in 40 CFR § 98.6.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion of kg to metric tons.

1.102311 = Conversion of metric tons to short tons

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

6. Emergency Diesel-powered Engines BACT Analysis (EPNs: FWP1, FWP2, EMGEN1 and EMGEN2)

Magellan will equip the site with four diesel-powered emergency engines. EMGEN1 and EMGEN2 emergency engines with a rating of 500kW and 100kW, respectively, will supply electrical power for control systems in the event of power outage. Meanwhile, the other two diesel-powered emergency engines (FWP1 and FWP2) with a rating of 617-hp will be used to power a firewater pump in the event of a fire. Magellan will use all these diesel-powered engines for emergency purposes only. They will each be limited to 100 hours per year of non-emergency operation for purposes of maintenance checks and readiness testing.

1) 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 emission potential, than liquid or solid fuels such as gasoline, diesel, or coal.
- *Vendor Certified Tier 4 and Clean Burn Engine* – Use of non-road diesel engines complying with 40 CFR Part 60, Subpart IIII will result in more efficient fuel use and reduced GHG emissions when compared to alternatives.
- *Good Combustion Practices and Maintenance* – Good combustion practices include appropriate maintenance of equipment and operating within the air to fuel ratio recommended by the manufacturer.
- *Limited Operation* – Limiting the hours of use during testing and maintenance will reduce the GHG emissions. The emergency engines will be limited to 100 hours of operation per year of non-emergency operation for purposes of maintenance checks and readiness testing.

2) Step 2 – Elimination of Technically Infeasible Alternatives

The purpose of the engines is to provide a source of water during a fire emergency and to supply electrical power in the event of power outage. The use of fuels like natural gas or propane may not be available during an emergency, necessitating a self-contained, stable and independent fuel supply. Gasoline fuel has a much higher volatility than diesel, and is thus less safe for use in an emergency situation, and it cannot be stored for long periods of time, which may be necessary for emergency use. Therefore, natural gas, propane and gasoline are eliminated as infeasible for these emergency engines. Good combustion practices and maintenance, use of clean burn engines, and limited operation are all applicable and feasible.

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

Limited operation, and good combustion practices and maintenance are all effective in minimizing emissions, but cannot be directly quantified, therefore ranking is not possible. In any case, since these controls are a suite of controls constituting BACT, no ranking is necessary.

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

Limited operation is directly applicable to the proposed engine since it is to be utilized for emergency use only, resulting in no emissions at most times. Operation for testing purposes is necessary to ensure operability when needed. A properly designed and maintained engine constitutes good operating practice for maximizing efficiency of all fuel combustion equipment, including emergency engines.

5) Step 5 – Selection of BACT

EPA proposes the following specific BACT practices for the diesel-powered emergency engines:

- *Vendor Certified Tier 4 and Clean Burn Engine* – Tier 4 and Clean Burn Engines complying with 40 CFR Part 60, Subpart IIII will be employed for the emergency generators and firewater pump engines.
- *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.
- *Limited Operation* – The emergency engines will not be operated more than 100 hours of non-emergency operation per engine per year. They will only be operated for maintenance, inspection and readiness testing. Compliance will be based on runtime hour meter readings on a 12-month rolling basis.

Using the BACT practices identified above results in an emission limit of 111 TPY CO_2e (total for the four engines). Magellan will demonstrate compliance with the CO_2 emission limit using the emission factors for Distillate Fuel Oil No. 2 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:

$$CO_2 = 0.001 * \text{Fuel} * \text{HHV} * \text{EF}$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of diesel fuel (metric tons)

Fuel = Annual volume diesel fuel combusted (gals). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to 40 CFR § 98.3(i).
HHV= Default high heat value of the fuel.
0.001 = Conversion of kg to metric tons.
EF = Fuel specific default CO_2 emission factor (kg CO_2/MMBtu).

Magellan will calculate CH_4 or N_2O emissions using the emission factors for petroleum fuel from 40 CFR Part 98 Subpart C, Table C-2. The equation for estimating CH_4 or N_2O emissions as specified in 40 CFR § 98.33(c)(1) is as follows:

$$CH_4 \text{ or } N_2O = 0.001 * \text{Fuel} * \text{HHV} * \text{EF}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O mass emissions from combustion of diesel fuel (metric tons)
Fuel = Annual volume diesel fuel combusted (gals). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to 40 CFR § 98.3(i).
HHV= Default high heat value of the fuel.
0.001 = Conversion of kg to metric tons.
EF = Fuel specific default CH_4 or N_2O emission factor (kg CO_2/MMBtu).

VIII. Endangered Species Act

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) submitted on March 4, 2014, prepared by the applicant, Magellan Processing, LLP ("Magellan"), and its consultant, Whitenton Group, Inc. ("Whitenton"), submitted June 2014 and revised August 2014, thoroughly reviewed and adopted by EPA. Magellan is proposing to construct and operate a condensate splitter facility at its existing plant located in Corpus Christi, Nueces County, Texas. For the purpose of Section 7 of the Endangered Species Act, EPA is relying on a Biological Assessment that includes the emissions from the entire project and their impacts to endangered species. The biological assessment performed for Magellan included a field survey of the physical land area where the new facilities will be built.

A draft BA has identified twenty-three (23) species listed as federally endangered or threatened in Nueces County, Texas:

Federally Listed Species for Nueces 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**
Reptiles	
Green sea turtle	*Chelonia mydas*
Hawksbill sea turtle	*Eretmochelys imbriacata*
Kemp's ridley sea turtle	*Lepidochelys kempii*
Leatherback sea turtle	*Dermochelys coriaea*
Loggerhead sea turtle	*Caretta caretta*
Birds	
Piping plover	*Charadrius melodus*
Northern Aplomado falcon	*Falco femoralis septentrionalis*
Whooping crane	*Grus americanus*
Red knot	*Calidris canutus rufa*
Eskimo curlew	*Numenius borealis*
Yellow-billed cuckoo	*Coccyzus americanus*
Fish	
Smalltooth sawfish	*Pristis pectinata*
Mammals	
Gulf coast jagaurundi	*Herpailuraus yagouaroundi cacomitli*
Ocelot	*Leopardus pardalis*
West Indian manatee	*Trichechus manatus*
Red wolf	*Canis rufus*
Plants	
Slender rush-pea	*Hoggmannseggia tenella*
South Texas ambrosia	*Ambrosia cheiranthifolia*
Whales	
Blue whale	*Balaenoptera musculus*
Fin whale	*Balaenoptera physalus*
Humpback whale	*Megaptera novaeangliae*
Sei whale	*Balaenoptera borealis*
Sperm whale	*Physeter macrocephalus*

EPA has determined that issuance of the proposed permits to Magellan for the new condensate splitter process facility will have no effect on twenty-two (22) of these listed species, specifically the green sea turtle (*Chelonia mydas*), hawksbill sea turtle (*Eretmochelys imbriacata*), Kemp's ridley sea turtle (*Lepidochelys kempii*), leatherback sea turtle (*Dermochelys coriaea*), loggerhead sea turtle (Caretta caretta), red wolf (*Canis rufus*), ocelot (*Leopardus pardalis*), Gulf coast jaguarundi (*Puma yagouaroundi cacomitli*), piping plover (*Charadrius melodus*), Northern Aplomado falcon (*Falco femoralis septentrionalis*), eskimo curlew (*Numenius borealis*), red knot (*Calidris canutus rufa*), yellow-billed cuckoo (*Coccyzus americanus*), smalltooth sawfish (*Pristis pectinata*), West Indian manatee (*Trichechus manatus*), blue whale (*Balaenoptera musculus*), fin whale (*Balaenoptera physalus*), humpback whale (*Megaptera novaeangliae*), sei whale (*Balaenoptera borealis*), sperm whale (*Physeter macrocephalus*), South Texas ambrosia (*Ambrosia cheiranthifolia*), and slender rush-pea (*Hoggmannseggia tenella*). These species are either thought to be extirpated from the county or Texas or not present in the action area.

One (1) terrestrial species, the whooping crane (*Grus americana*), is a species that may be present in the action area as the proposed project is approximately 36 miles southwest of whooping crane critical habitat, Aransas National Wildlife Refuge, and is within the whooping crane's migration corridor. 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 whooping crane. Magellan has agreed to implement measures to minimize any potential adverse effects the project may have on the whooping crane, as indicated in their Biological Assessment.

On August 13, 2014, EPA submitted the final draft BA, dated August 2014, 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 whooping crane.

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.

IX. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA thoroughly reviewed, relied on and adopted a cultural resources report submitted May 21, 2014 and prepared by Horizon Environmental Services (Horizon) on behalf of the Whitenton Group, a contractor for Magellan.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 140 acres, consisting of the current facility site (104 acres), a construction laydown area (formerly residential property, 29 acres) and linear facilities (3 pipelines to be added to an existing pipeline corridor about a mile long, 6.5 acres).

Horizon performed a desktop review on the archeological background and historical records within a one-mile radius of the APE. The desktop review included an archaeological background and historical records review using the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP). Based on the results of the survey, no known cultural or archeological sites exist within the APE or a one-mile radius of the APE.

EPA Region 6 determines that since there are no historic properties or archaeological resources located within the APE, issuance of the permits to Magellan will not affect properties potentially eligible for listing on the National Register.

On June 20, 2014, 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. On August 13, 2014. EPA provided a copy of the report to Texas's State Historic Preservation Officer (SHPO) for consultation and concurrence with its determination. SHPO provided concurrence and agreed with EPA's determinations on August 28, 2014.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

X. 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.

XI. Conclusion and Proposed Action

Based on the information supplied by GPP, our review of the analyses contained in the TCEQ PSD Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue Magellan 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

Table 1. Annual Emission Limits
Annual emissions, in tons per year (TPY) on a 365-day, rolling total, shall not exceed the following

FIN	EPN	Description	GHG Mass Basis		CO_2e[1,2] (TPY)	BACT Requirements
				TPY[1]		
H-1A	H-1A	Fractionator Heater - Train 1	CO_2	60,049	60,111	Minimum thermal efficiency of 85%. See permit condition III.B.1.o.
			CH_4	1.13		
			N_2O	0.11		
H-1B	H-1B	Hot Oil Heater - Train 1	CO_2	49,289	49,340	Minimum thermal efficiency of 85%. See permit condition III.B.1.o.
			CH_4	0.93		
			N_2O	0.09		
H-2A	H-2A	Fractionator Heater – Train 2	CO_2	60,049	60,111	Minimum thermal efficiency of 85%. See permit condition III.B.1.o.
			CH_4	1.13		
			N_2O	0.11		
H-2B	H-2B	Hot Oil Heater – Train 2	CO_2	49,289	49,340	Minimum thermal efficiency of 85%. See permit condition III.B.1.o.
			CH_4	0.93		
			N_2O	0.09		
H-4	H-4	Tank Heater	CO_2	4,099	4,103	Design thermal efficiency of 85%. Not to exceed 4,380 hours of equivalent full load operation on a 12-month rolling basis. See permit condition III.B.1.r
			CH_4	0.075		
			N_2O	No Numerical Limit Established[3]		
FL-1	FL-1	Flare	CO_2	576	577	Good combustion practices. See permit condition III.B.2.
			CH_4	0.02		
			N_2O	No Numerical Limit Established[3]		
FWP1 FWP2	FWP1 FWP2	Diesel-powered Fire Water Pumps	CO_2	64	64	Limit hours of non-emergency operation and good combustion practices. See permit condition III.B.5.
			CH_4	No Numerical Limit Established[3]		
			N_2O	No Numerical Limit Established[3]		
EMGEN 1 EMGEN 2	EMGEN1 EMGEN2	Diesel-powered Emergency Generators	CO_2	47	47	Limit hours of non-emergency operation and good combustion practices. See permit condition III.B.5.
			CH_4	No Numerical Limit Established[3]		
			N_2O	No Numerical Limit Established[3]		
MSSVC U	MSSVCU	MSS Vapor Combustion Unit	CO_2	2,645	2,648	Maintain a minimum combustion temperature. See permit condition III.B.4.
			CH_4	0.056		
			N_2O	No Numerical Limit Established[3]		

Table 1. Annual Emission Limits Annual emissions, in tons per year (TPY) on a 365-day, rolling total, shall not exceed the following						
FIN	**EPN**	**Description**	**GHG Mass Basis**		**CO_2e[1,2] (TPY)**	**BACT Requirements**
				TPY[1]		
FUG-1	FUG-1	Components Fugitive Leak Emissions	CH_4	No Numerical Limit Established[4]	No Numerical Limit Established[4]	See permit condition III.B.3.
Totals[5]			CO_2	**226,106**	**CO_2e 226,502[6]**	
			CH_4	**10.565**		
			N_2O	**0.426**		

1. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
2. Global Warming Potentials (GWP): CO_2=1, CH_4 = 25, N_2O = 298, SF_6=22,800
3. 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.
4. Fugitive process emission from FUG-1 are estimated to be 6.42 TPY of CH_4 and 160 TPYCO_2e.
5. The total emissions for CH4 and CO_2 e include the PTE for process fugitive emissions of CH4. The total emissions for CO_2e, also, include PTE emission of an existing tank heater (H-3). These totals are given for informational purpose only and do not constitute emission limits.
6. Two existing marine vessel loading vapor combustion units (EPNs: VCU1 and VCU2) and one existing tank heater (EPN: H-3) at the Corpus Christi Terminal will be used as part of the condensate splitter process but are not being physically modified themselves. They have a total estimated GHG emissions of 15,723 tpy CO_2e. As explained in the GHG Permitting Guidance, for the purposes of determining whether a PSD permits is required, the EPA requires a permitting authority to look beyond the emissions unit that is modified (across the entire source) to determine the extent of emission increases that result from the modification. However, the BACT applies only to the emission unit(s) that have been modified or added to the existing facility. See PSD and Title V permitting Guidance for Greenhouse Gases at 23. As a result, any additional GHG emissions from the condensate splitter process have been included in calculating the total tpy CO_2e to determine the PSD applicability. EPA will not, however, conduct a BACT analysis for the existing marine vessel loading vapor combustion units (VCU1 and VCU2) and tank heater (H-3) as part of this permit.