PREVENTION OF SIGNIFICANT DETERIORATION PERMIT FOR GREENHOUSE GAS EMISSIONS ISSUED PURSUANT TO THE REQUIREMENTS AT 40 CFR § 52.21

U.S. ENVIRONMENTAL PROTECTION AGENCY, REGION 6

PSD PERMIT NUMBER:	PSD-TX-110557-GHG
PERMITTEE:	DCP Midstream, LP 370 17th Street, Suite 2500 Denver, CO 80202
FACILITY NAME:	Jefferson County NGL Fractionation Plant
FACILITY LOCATION:	Hillebrandt Road 3.2 miles North of Steinhagen Road Beaumont, TX 77707

Pursuant to the provisions of the Clean Air Act (CAA), Subchapter I, Part C (42 U.S.C. Section 7470, *et. Seq.*), and the Code of Federal Regulations (CFR) Title 40, Section 52.21, and the Federal Implementation Plan at 40 CFR § 52.2305 (effective May 1, 2011 and published at 76 FR 25178), the U.S. Environmental Protection Agency, Region 6 is issuing a *Prevention of Significant Deterioration* (PSD) permit to DCP Midstream LP (DCP) for Greenhouse Gas (GHG) emissions. The Permit applies to the construction of two new natural gas liquids (NGL) fractionation trains to separate a NGL feed into separate ethane, propane, butane, isobutane, and natural gasoline fractions. Each train will include a deisobutanizer (DIB) column to separate isobutane and normal butane from a mixed butane stream. The facility will be located in Beaumont, Texas.

DCP is authorized to construct two new NGL fractionation trains each with a DIB column as described herein, in accordance with the permit application (and plans submitted with the permit application), the federal PSD regulations at 40 CFR § 52.21, and other terms and conditions set forth in this PSD permit in conjunction with the corresponding Texas Commission on Environmental Quality (TCEQ) NSR permit No. 110557. Failure to comply with any condition or term set forth in this PSD Permit may result in enforcement action pursuant to Section 113 of the Clean Air Act (CAA). This PSD Permit does not relieve DCP of the responsibility to comply with any other applicable provisions of the CAA (including applicable implementing regulations in 40 CFR Parts 51, 52, 60, 61, 72 through 75, and 98) or other federal and state requirements (including the state PSD program that remains under approval at 40 CFR § 52.2303).

In accordance with 40 CFR §124.15(b), this PSD Permit becomes effective 30 days after the service of notice of this final decision unless review is requested on the permit pursuant to 40 CFR §124.19.

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Wren Stenger, Director — Date
Multimedia Planning and Permitting Division

Draft for August 7, 2013

DCP Midstream LP (PSD-TX-110557-GHG)
Prevention of Significant Deterioration Permit
For Greenhouse Gas Emissions
Draft Permit Conditions

PROJECT DESCRIPTION

This permit authorizes the construction of two new natural gas liquids (NGL) fractionation trains each with a deisobutanizer (DIB) column in Beaumont, Texas. The Jefferson County NGL Fractionation Plant will be capable of separating a Y-grade NGL feed into liquid products (ethane, propane, normal butane, isobutane, and natural gasoline). The DIB column will be capable of separating isobutane and normal butane from mixed butane stream. The facility will be designed with a nominal capacity of 75,000 barrels per day (bpd) per train and includes amine treating, natural gasoline treating, molecular sieve dehydration utilizing regeneration heaters, hot oil heaters as the primary heat source, refrigerant propylene and wet surface air coolers/condensers (WSAC) for cooling and condensation, a thermal oxidizer (TO) for control of waste gas streams, and a flare. The throughput of an individual train may exceed 75,000 bpd and is dependent on the inlet NGL composition without exceeding the CO_2e emissions estimated in the GHG PSD permit application. Compression for the propylene refrigeration and process heat pumps will be accomplished using compressors powered by electric motors. The hot oil heaters for the process are heated using a natural gas-fired heater for each train. Heat exchangers will be incorporated throughout the process to take advantage of heating and cooling efficiencies. The GHG emissions will be generated by the two hot oil heaters, two regeneration heaters, two thermal oxidizers, engines, and the flare. All other new units at the facility are either a closed system, have only fugitive emissions, or vent to the flare.

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit.

FIN	EPN	Description
HOH1 HOH2	HOH1 HOH2	2 Hot Oil Heaters (Combustion Unit). Each unit has a maximum design heat input rate of 179 MMbtu/hr, and is fired with natural gas.
HTR1 HTR2	HTR1 HTR2	2 Regenerant Heaters (Combustion Units). Each unit has a maximum design heat input rate of 36 MMbtu/hr, and is fired with natural gas.
ENG1	ENG1	Emergency Firewater Pump Engine (Combustion Unit). 500 HP diesel fired engine.
ENG2	ENG2	Emergency Generator Engine (Combustion Unit). 500 HP diesel fired engine.
FLR1	FLR1	Flare (Combustion Unit).
TO1 TO2	TO1 TO2	Thermal Oxidizers (Combustion Units).
TE1 TE2	TE1 TE2	Analyzer Catalytic Oxidizers
FUG1 FUG2	FUG1 FUG2	Process Fugitives

I. GENERAL PERMIT CONDITIONS

A. PERMIT EXPIRATION

As provided in 40 CFR §52.21(r), this PSD Permit shall become invalid if construction:

1. is not commenced (as defined in 40 CFR §52.21(b)(9)) within 18 months after the approval takes effect; or

2. is discontinued for a period of 18 months or more; or

3. is not completed within a reasonable time.

Pursuant to 40 CFR §52.21(r), EPA may extend the 18-month period upon a written satisfactory showing that an extension is justified.

B. PERMIT NOTIFICATION REQUIREMENTS

Permittee shall notify EPA Region 6 in writing or by electronic mail of the:

1. date construction is commenced, postmarked within 30 days of such date;

2. actual date of initial startup, as defined in 40 CFR §60.2, postmarked within 15 days of such date; and

3. date upon which initial performance tests will commence, in accordance with the provisions of Section V, postmarked not less than 30 days prior to such date. Notification may be provided with the submittal of the performance test protocol required pursuant to Condition V.B.

C. FACILITY OPERATION

At all times, including periods of startup, shutdown, and maintenance, Permittee shall, to the extent practicable, maintain and operate the facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA, which may include, but is not limited to, monitoring results, review of operating maintenance procedures and inspection of the facility.

D. MALFUNCTION REPORTING

1. Permittee shall notify EPA by mail within 48 hours following the discovery of any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner, which results in an increase in GHG emissions above the allowable emission limits stated in Section II and III of this permit.

2. Within 10 days of the restoration of normal operations after any failure described in I.D.1., Permittee shall provide a written supplement to the initial notification that includes a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in Section II and III, and the methods utilized to mitigate emissions and restore normal operations.
3. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.

E. RIGHT OF ENTRY

EPA authorized representatives, upon the presentation of credentials, shall be permitted:

1. to enter the premises where the facility is located or where any records are required to be kept under the terms and conditions of this PSD Permit;

2. during normal business hours, to have access to and to copy any records required to be kept under the terms and conditions of this PSD Permit;

3. to inspect any equipment, operation, or method subject to requirements in this PSD Permit; and,

4. to sample materials and emissions from the source(s).

F. TRANSFER OF OWNERSHIP

In the event of any changes in control or ownership of the facilities to be constructed, this PSD Permit shall be binding on all subsequent owners and operators. Permittee shall notify the succeeding owner and operator of the existence of the PSD Permit and its conditions by letter; a copy of the letter shall be forwarded to EPA Region 6 within thirty days of the letter signature.

G. SEVERABILITY

The provisions of this PSD Permit are severable, and, if any provision of the PSD Permit is held invalid, the remainder of this PSD Permit shall not be affected.

H. ADHERENCE TO APPLICATION AND COMPLIANCE WITH OTHER ENVIRONMENTAL LAWS

Permittee shall construct this project in compliance with this PSD Permit, the application on which this permit is based, the TCEQ NSR Permit No. 110557 (when issued) and all other applicable federal, state, and local air quality regulations. This PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

I. ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
BACT	Best Available Control Technology
CAA	Clean Air Act
CC	Carbon Content
CCS	Carbon Capture and Sequestration
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
DIB	Deisobutanizer
dscf	Dry Standard Cubic Foot
EF	Emission Factor
EPN	Emission Point Number
FIN	Facility Identification Number
FR	Federal Register
GHG	Greenhouse Gas
gr	Grains
GWP	Global Warming Potential
HHV	High Heating Value
hr	Hour
LAER	Lowest Achievable Emission Rate
lb	Pound
LDAR	Leak Detection and Repair
MMBtu	Million British Thermal Units
MSS	Maintenance, Start-up and Shutdown
NNSR	Nonattainment New Source Review
N_2O	Nitrous Oxides
NSPS	New Source Performance Standards
PSD	Prevention of Significant Deterioration
QA/QC	Quality Assurance and/or Quality Control
SCF	Standard Cubic Feet
SCR	Selective Catalytic Reduction
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TPY	Tons per Year
USC	United States Code
VOC	Volatile Organic Compound

II. Annual Emission Limits

Annual emissions, in tons per year (TPY) calculated on a 12-month rolling basis, shall not exceed the following:

Table 1. Annual Emission Limits[1]

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
HOH1	HOH1	Hot Oil Heater - Train 1	CO_2	78,422	78,500	Minimum Thermal Efficiency of 85%. See permit condition III.A.1.r.
			CH_4	1.48		
			N_2O	0.15		
HOH2	HOH2	Hot Oil Heater - Train 2	CO_2	78,422	78,500	Minimum Thermal Efficiency of 85%. See permit condition III.A.1.r.
			CH_4	1.48		
			N_2O	0.15		
HTR1	HTR1	Regeneration Heater - Train 1	CO_2	12,959	12,970	Minimum Thermal Efficiency of 80% and Limit of 6,000 hr/yr at Max Firing. See permit conditions III.A.2.i. and III.A.2.u.
			CH_4	0.24		
			N_2O	0.02		
HTR2	HTR2	Regeneration Heater - Train 2	CO_2	12,959	12,970	Minimum Thermal Efficiency of 80% and Limit of 6,000 hr/yr at Max Firing. See permit conditions III.A.2.i. and III.A.2.u.
			CH_4	0.24		
			N_2O	0.02		
FLR1	FLR1	Flare	CO_2	7,215	9,447	Use of Good Combustion Practices. See permit condition III.A.5.
			CH_4	0.91		
			N_2O	7.14		
TO1	TO1	Thermal Oxidizer - Train 1	CO_2	8,820	8,825	Minimum firebox temperature based on performance testing. See permit condition III.A.3.b and III.A.3.h.
			CH_4	0.07		
			N_2O	0.01		
TO2	TO2	Thermal Oxidizer - Train 2	CO_2	8,820	8,825	Minimum firebox temperature based on performance testing. See permit condition III.A.3.b and III.A.3.h.
			CH_4	0.07		
			N_2O	0.01		
ENG1	ENG1	Firewater Pump Engine	CO_2	28.5	29	Good combustion practices, non-emergency operation limited to 100 hrs./year. See permit conditions at III.A.6.
			CH_4	0.02		
			N_2O	No Numerical Limit Established[4]		

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

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling basis.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 21, N_2O = 310
4. The emissions are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
5. Fugitive process emissions from EPNs FUG1 and FUG2 are estimated to be 0.34 TPY of CO_2, 1.92 TPY of CH_4, and 40.7 TPY CO_2e. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
6. The total emissions for CO_2, CH_4, and CO_2e include the PTE for process fugitive emissions of CO_2, CH_4, and CO2e. These totals are given for informational purposes only and do not constitute emission limits.

III. SPECIAL PERMIT CONDITIONS

A. Emission Unit Work Practice Standards, Operational Requirements, and Monitoring

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

    a. Each fractionation train shall be equipped with one hot oil heater.
    b. Permittee shall calculate, on a monthly basis, the amount of CO_2 emitted from combustion in tons/yr using equation C-2a in 40 CFR Part 98 Subpart C, converted to short tons. Compliance shall be based on a 12-month rolling basis.
    c. Permittee shall calculate the CH_4 and N_2O emissions on a 12-month rolling basis. Permittee shall determine compliance with the CH_4 and N_2O emissions limits contained in this section using the default CH_4 and N_2O emission factors contained in Table C-2 and equation C-9a of 40 CFR Part 98 and the measured actual heat input (HHV), converted to short tons.
    d. Permittee shall calculate the CO_2e emissions on a 12-month rolling basis, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on October 30, 2009 (74 FR 56395).
    e. Fuel for the heaters shall be limited to pipeline quality natural gas with a fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf). The fuel gross calorific value (GCV) [high heat value (HHV)] of the fuel shall be determined, at a minimum, semiannually by the procedures contained in 40 CFR Part 98.34(a)(6) and records shall be maintained of the semiannual fuel GCV for a period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in the heaters or shall allow a sample to be taken by EPA for analysis.
    f. The Permittee shall measure and record the fuel flow rate using an operational non-resettable elapsed flow meter or by recording the flow rate data in an electronic format with individual flow measurements being taken no less frequently than once every 15 minutes. Electronic data may be reduced to hourly averages for recordkeeping purposes.
    g. Permittee shall calibrate and perform a preventative maintenance check of the fuel gas flow meters and document annually.
    h. Permittee shall clean the burner tips of each hot oil heater during an annual shutdown if occurring. If a planned outage is not performed, cleaning may be delayed until the next planned outage, not to exceed 5 years from the previous cleaning.
    i. Permittee shall install, operate, and maintain an automated air/fuel control system.
    j. Permittee shall calibrate and perform preventative maintenance on the air/fuel control analyzers once per quarter, at a minimum.

k. Permittee shall utilize insulation materials (e.g. ceramic fiber blankets and Kaolite™) where feasible to reduce heat loss.
l. Permittee shall install, operate, and maintain an O_2 analyzer on each of the hot oil heaters (HOH1 and HOH2).
m. Oxygen analyzers shall continuously monitor and record oxygen concentration in the hot oil heaters (HOH1 and HOH2). It shall reduce the oxygen readings to an averaging period of 15 minutes or less and record it at that frequency.
n. A relative accuracy test audit (RATA) is required once every four quarters in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.1.
o. The oxygen analyzers shall be quality-assured at least quarterly using cylinder gas audits (CGAs) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.2.
p. The oxygen content will be limited to a maximum of 15% O_2.
q. The one-hour maximum firing rate for the hot oil heaters (HOH1 and HOH2) shall not exceed 179 MMBtu/hr per unit. The annual average firing rate shall not exceed 150 MMBtu/hr.
r. A rolling 12-month average firing rate shall be calculated monthly and the one-hour maximum firing rates shall be calculated daily to demonstrate compliance with the firing rates in III.A.1.p.
s. The Permittee shall maintain a minimum overall thermal efficiency of 85% on a 12-month rolling average basis, calculated monthly, for the hot oil heaters (HOH1 and HOH2) excluding periods of start-up, shutdown, and malfunction.
t. The hot oil heaters (HOH1 and HOH2) will be continuously monitored for exhaust temperature, input fuel temperature, and stack oxygen. Thermal efficiency for the hot oil heaters will be calculated monthly from these parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4^{th} ed.) Annex G.
u. The heaters shall not have GHG emissions in excess of the allowed emission rates during periods of startup, shutdown, or maintenance. The fuel firing rates shall not exceed the maximum firing rate.

2. Regeneration Heaters (EPNs: HTR1 and HTR2)

a. Each fractionation train shall be equipped with one regeneration heater.
b. Permittee shall calculate, on a monthly basis, the amount of CO_2 emitted from combustion in tons/yr using equation C-2a in 40 CFR Part 98 Subpart C, converted to short tons. Compliance shall be based on a 12-month rolling basis.
c. Permittee shall calculate the CH_4 and N_2O emissions on a 12-month rolling basis. Permittee shall determine compliance with the CH_4 and N_2O emissions limits contained in this section using the default CH_4 and N_2O emission factors contained in Table C-2 and equation C-9a of 40 CFR Part 98 and the measured actual heat input (HHV), converted to short tons.

d. Permittee shall calculate the CO_2e emissions on a 12-month rolling basis, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on October 30, 2009 (74 FR 56395).
e. Fuel for the heaters shall be limited to pipeline quality natural gas with a fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf). The fuel gross calorific value (GCV) [high heat value (HHV)] of the fuel shall be determined, at a minimum, semiannually by the procedures contained in 40 CFR Part 98.34(a)(6) and records shall be maintained of the semiannual fuel GCV for a period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in the heaters or shall allow a sample to be taken by EPA for analysis.
f. The flow rate of the fuel combusted in natural gas-fired combustion emission units identified in this section shall be measured and recorded using an operational totalizing fuel flow meter at each inlet.
g. Permittee shall calibrate and perform a preventative maintenance check of the fuel gas flow meters and document annually.
h. Permittee shall install and maintain an operational non-resettable elapsed hour meter for the regeneration heaters (HTR1 and HTR2).
i. Each regeneration heater shall be limited to operate 6,000 hours per year at the maximum firing rate.
j. The maximum firing rate for the regeneration heaters (HTR1 and HTR2) shall not exceed 36 MMBtu/hr per unit.
k. Permittee shall monitor the regeneration heaters (HTR1 and HTR2) exhaust oxygen content using portable stack gas analyzers.
l. The exhaust oxygen content of each regeneration heater (HTR1 and HTR2) shall be monitored semi-annually for a period of 15 minutes and recorded at the beginning and end of the 15 minute period. If monitoring indicates an exhaust oxygen content of greater than 15% O_2, then the air /fuel mixture will be manually adjusted and the exhaust monitored again after adjustment to verify the oxygen content does not exceed 15% O_2.
m. Exhaust oxygen content will be limited to a maximum of 15% O_2 based on the semiannual monitoring.
n. Permittee shall utilize insulation materials (e.g. ceramic fiber blankets and Kaolite™) where feasible to reduce heat loss.
o. The Permittee shall maintain a minimum overall thermal efficiency of 80% based on an annual rolling average calculated semiannually using data from the two most recent semiannual stack tests.
p. The regeneration heaters (HTR1 and HTR2) will be monitored for exhaust temperature, input fuel temperature, and stack oxygen during the semiannual stack test. Thermal efficiency for the regeneration heaters will be calculated semiannually

from these parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4th ed.) Annex G.

q. The heaters are not expected to have GHG emissions in excess of the allowed emission rates during periods of startup, shutdown, or maintenance. The fuel firing rates will be below the maximum rate.

3. Thermal Oxidizers (EPNs: TO1 and TO2)

   a. Each fractionation train shall be equipped with one thermal oxidizer.
   b. An initial stack test on the thermal oxidizer shall be conducted to verify compliance with the emission limit specified in Table 1 and to verify the destruction and removal efficiency (DRE) of at least 99.9% for VOC.
   c. For burner combustion, natural gas fuel usage (scf) is recorded using an operational non-resettable elapsed flow meter at the thermal oxidizer.
   d. The flow rate of the waste gas combusted shall be measured and recorded using an operational non-resettable elapsed flow meter at the thermal oxidizer.
   e. Waste gas will be sampled and analyzed on a quarterly basis for composition. The sampled data will be used to calculate GHG emissions to show compliance with the limits specified in Table 1.
   f. Permittee shall calculate CO_2 emissions, on a monthly basis, using equation W-3 in 40 CFR Part 98, Subpart W §98.233(d)(2), converted to mass emissions in short tons.
   g. Periodic maintenance will help maintain the efficiency of the thermal oxidizer and shall be performed at a minimum annually or more often as recommended by the manufacturer specifications.
   h. The Permittee shall maintain the combustion temperature at a minimum of 1,500 ºF until the initial performance testing occurs at which time the minimum temperature will be revised consistent with the minimum required to maintain a 99.9% DRE at all times when processing waste gases in the thermal oxidizer. The results of the initial performance testing must be submitted to EPA for approval.
   i. The Permittee shall install and maintain a temperature recording device with an accuracy of the greater of ±0.75 percent of the temperature being measured expressed in degrees Fahrenheit or ±4.5 ºF. The firebox temperature shall be monitored continuously and recorded on an hourly basis during all times when processing waste gases in the thermal oxidizer.

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

   a. Each fractionation train shall be equipped with one analyzer utilizing catalytic oxidizers (TRACErase™ technology or equivalent technology).

b. The Permittee shall perform preventative maintenance to include catalyst cartridge replacement on an annual basis.
c. The permittee shall not exceed 5,520 scf/yr of waste gas emissions sent to each analyzer catalytic oxidizer for control on a 12-month rolling basis.
d. The Permittee shall keep records of the waste gas flow that is controlled by each analyzer catalytic oxidizer.

5. Flare (EPN: FLR1)

a. Permittee shall install, operate, and maintain a flow rate and composition analyzer to monitor the waste gas combusted by the flare. The flow rate and composition analyzer shall continuously sample the flare gas stream and record the molecular weight and mass flow rate of the flare gas consistent with the stream analyzer frequency.
b. The flare shall be air assisted.
c. Flare shall have a minimum destruction and removal efficiency (DRE) of 98% based on flowrate and gas composition.
d. Permittee must record the inlet waste gas heat input (HHV) in MMBtu/hr during flare operation. The records must include hourly CH_4 emission levels as measured by the in-line gas analyzer (Gas chromatograph or equivalent with inlet gas flowrate) and the calculations based on the actual heat input for the CO_2, N_2O, and CH_4 emissions. These records must be kept for five years following the date of each event.
e. Emissions shall be calculated according to 40 CFR §98.233(n)(4) through (n)(8), converted to short tons.
f. The flare shall be designed and operated in accordance with 40 CFR 60.18 including specifications of minimum heating value of the waste gas, maximum tip velocity, and pilot flame monitoring. An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes.

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

a. The engines shall be diesel fired. Fuel used in the engines will meet the requirements of 40 CFR 80.510(b) regarding sulfur content (15 ppmw maximum) and a minimum Cetane Index of 40 or maximum aromatic content of 35% by volume.
b. The Permittee shall install a non-resettable hour meter prior to start-up of each engine.
c. The emergency firewater pump engine purchased will be certified to meet the applicable emission standards of 40 CFR 60.4205(c).

d. The emergency generator engines purchased will be certified to meet the applicable emission standards of 40 CFR 60.4205(b).
e. The engines may be operated for the purpose of maintenance checks and readiness testing for up to 100 hours per year per engine.
f. The emission limit in Table 1 is based on each emergency generator engine operating 100 hours a year for maintenance and testing.
g. Compliance with the Annual Emission Limit shall be demonstrated on a 12-month total, rolling monthly, calculated in accordance with 40 CFR Part 98 Subpart C §98.33(a)(1)(i).

7. Process Fugitives (EPNs: FUG1 and FUG2)

The Permittee shall implement the TCEQ 28LAER leak detection and repair (LDAR) program for fugitive emissions of methane.

B. Continuous Emissions Monitoring Systems (CEMS)

1. As an alternative to Special Conditions III.A.1.b, III.A.2.b, and III.A.3.f. Permittee may install a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions discharged to the atmosphere, and use these values to show compliance with the annual emission limit in Table 1.
2. Permittee shall ensure that all required CO_2 monitoring system/equipment are installed and all certification tests are completed on or before the earlier of 90 unit operating days or 180 calendar days after the date the unit commences operation.
3. Permittee shall ensure compliance with the specifications and test procedures for CO_2 emission monitoring system at stationary sources, 40 CFR Part 75, or 40 CFR Part 60, Appendix B, Performance Specification numbers 1 through 9, as applicable.
4. Permittee shall meet the appropriate quality assurance requirements specified in 40 CFR Part 60, Appendix F for the CO_2 emission monitoring system.

IV. Recordkeeping and Reporting

1. In order to demonstrate compliance with the GHG emission limits in Table 1, the Permittee will monitor the following parameters and summarize the data on a calendar month basis.

    a. Operating hours for all air emission sources;
    b. The natural gas fuel usage for all combustion sources, using continuous fuel flow monitors (a group of equipment can utilize a common fuel flow meter, as long as actual fuel usage is allocated to the individual equipment based upon actual operating hours and maximum firing rate); and

c. Annual fuel sampling for natural gas, and quarterly sampling of waste gas at a minimum.

2. Permittee shall maintain and keep records of the monitoring results, as well as the repair and maintenance records in implementing the TCEQ 28LAER leak detection and repair program.
3. Permittee shall maintain all records, data, measurements, reports, and documents related to the operation of the facility, including, but not limited to, the following: all records or reports pertaining to significant maintenance performed on any system or device at the facility; duration of startup, shutdown; the initial startup period for the emission units; pollution control units; malfunctions; all records relating to performance tests, calibrations, checks, and monitoring of combustion equipment; duration of an inoperative monitoring device and emission units with the required corresponding emission data; and all other information required by this permit recorded in a permanent form suitable for inspection. The records must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.
4. Permittee shall maintain records of all GHG emission units and CO_2 emission certification tests and monitoring and compliance information required by this permit.
5. Permittee shall maintain records and submit a written report of all excess emissions to EPA semi-annually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator or authorized representative, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. The report is due on the 30th day following the end of each semi-annual period and shall include the following:

   a. Time intervals, data and magnitude of the excess emissions, the nature and cause (if known), corrective actions taken and preventive measures adopted;
   b. Applicable time and date of each period during which the monitoring equipment was inoperative (monitoring down-time);
   c. A statement in the report of a negative declaration; that is,a statement when no excess emissions occurred or when the monitoring equipment has not been inoperative, repaired or adjusted; and
   d. Any failure to conduct any required source testing, monitoring, or other compliance activities.

6. Excess emissions shall be defined as any period in which the facility emissions exceed a maximum emission limit set forth in this permit.
7. Excess emissions indicated by GHG emission source certification testing or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.

8. All records required by this PSD Permit shall be retained and remain accessible for not less than 5 years following the date of such measurements, maintenance, and reporting.

V. **Initial Performance Testing Requirements**:

A. The holder of this permit shall perform an initial stack test to establish the actual quantities of air contaminants being emitted into the atmosphere from emission units HOH1, HOH2, HTR1, HTR2, TO1, and TO2 and to determine the initial compliance with the CO_2 emission limits established in this permit. Sampling shall be conducted in accordance with 40 CFR § 60.8 and EPA Method 3a or 3b, in 40 CFR 60 Appendix B, for the concentration of CO_2 for the heaters.

1. Multiply the CO_2 hourly average emission rate determined under maximum operating test conditions by 8,760 hours for the Hot Oil Heaters (HOH1 and HOH2) and Thermal Oxidizers (TO1 and TO2), and 6,000 hours for the Regeneration Heaters (HTR1 and HTR2).
2. If the above calculated CO_2 emission total does not exceed the tons per year (TPY) specified on Table 1, no compliance strategy needs to be developed.
3. If the above calculated CO_2 emission total exceeds the tons per year (TPY) specified in Table 1, the facility shall;
   a. Document the exceedance in the test report; and
   b. Explain within the report how the facility will assure compliance with the CO_2 emission limit listed in Table 1.

B. The Permittee shall conduct an evaluation of the thermal efficiency of the hot oil heaters (HOH1 and HOH2) and regeneration heaters (HTR1 and HTR2) to verify compliance with minimal thermal efficiency requirements at III.A.1.r.and III.A.2.o. when performing testing as stated in V.A. above. The results of the thermal efficiency evaluation shall be submitted to the EPA within 30 days of testing. Thermal efficiency of the regeneration heaters (HTR1 and HTR2) shall be retested semiannually.

C. Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility, performance tests(s) must be conducted and a written report of the performance testing results furnished to the EPA. Additional sampling may be required by TCEQ or EPA.

D. Permittee shall submit a performance test protocol to EPA no later than 30 days prior to the test to allow review of the test plan and to arrange for an observer to be present at the test. The performance test shall be conducted in accordance with the submitted protocol, and any changes required by EPA.

E. Performance testing must be conducted using flow rates that are comparable to the normal operating flow rates.

F. Fuel sampling for emission unit FLR1 (flare) shall be conducted in accordance with 40 CFR Part 98.

G. Flare compliance determinations shall be made following the requirements in 40 CFR Part 60 sections 60.18(f)(1) through 60.18(f)(4).

H. The Permittee shall perform initial performance demonstration testing of the thermal oxidizers (TO1 and TO2) at the site. The thermal oxidizers shall be operated at the maximum production rate during stack emissions testing. The Permittee shall measure CH_4 concentrations and mass rates in the thermal oxidizer inlet and exhaust streams to demonstrate a minimum destruction efficiency of 99.9% by weight and a minimum combustion chamber temperature required to achieve 99.9% destruction efficiency. The minimum temperature demonstrated must be approved by EPA.

I. The Permittee shall record the combustion chamber temperature and combustion chamber set-point temperature during the performance test. These and any additional operational parameters shall be identified in the test protocol and recorded during testing. Following the performance test, the thermal oxidizers shall be operated at or above the combustion chamber set-point temperature established by the initial performance test until re-established in subsequent performance testing.

J. For the thermal oxidizers, the sampling site and velocity traverse point shall be selected in accordance with EPA Test Method 1or 1A, 40 CFR Part 60. The gas volumetric flow rate shall be measured in accordance with EPA Test Method 2, 2A, 2C, 2D, 2F, 2G, or 19. The dry molecular weight shall be determined in accordance with EPA Test Method 3, 3A or 3B. The stack gas moisture shall be determined in accordance with EPA Test Method 4. These methods must be performed, as applicable, during each test run.

K. Performance tests must be conducted under such conditions to ensure representative performance of the affected facility. The owner or operator must make available to the EPA such records as may be necessary to determine the conditions of the performance tests.

L. The owner or operator must provide the EPA at least 30 days' prior notice of any performance test, except as specified under other subparts, to afford the EPA the opportunity to have an observer present and/or to attend a pre-test meeting. If there is a delay in the original test date, the facility must provide at least 7 days prior notice of the rescheduled date of the performance test.

M. The owner or operator shall provide, or cause to be provided, performance testing facilities as follows:

1. Sampling ports adequate for test methods applicable to this facility,
2. Safe sampling platform(s),
3. Safe access to sampling platform(s), and
4. Utilities for sampling and testing equipment.

N. Unless otherwise specified, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For purposes of determining compliance with an applicable standard, the arithmetic mean of the results of the three runs shall apply.

O. Emissions testing, as outlined above, shall be performed every three years, or more frequently if identified above, to verify continued performance at permitted emission limits.

VI. Agency Notifications

Permittee shall submit GHG permit applications, permit amendments, and other applicable permit information to:

Multimedia Planning and Permitting Division
EPA Region 6
1445 Ross Avenue (6 PD-R)
Dallas, TX 75202
Email: Group R6AirPermits@EPA.gov

Permittee shall submit a copy of all compliance and enforcement correspondence as required by this Approval to Construct to:

Compliance Assurance and Enforcement Division
EPA Region 6
1445 Ross Avenue (6EN)
Dallas, TX 75202