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-1388-GHG
PERMITTEE:	CCI Corpus Christi, LLC 811 Main St, Suite 3500 Houston, TX 77002
FACILITY NAME:	Condensate Splitter Facility
FACILITY LOCATION:	4820 E. Navigation Boulevard (Carbon Plant Rd.) Corpus Christi, TX 78402

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 CCI Corpus Christi, LLC (CCI) for Greenhouse Gas (GHG) emissions. The Permit applies to the construction of a new condensate splitter plant and bulk petroleum terminal near Corpus Christi, Texas.

CCI is authorized to construct a new condensate splitter plant 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) PSD permit No. PSD-TX-1388 and minor New Source Review (NSR) permit No. 116072. 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 CCI 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).

________________________________ __________________
Wren Stenger, Director — Date
Multimedia Planning and Permitting Division

CCI Corpus Christi, LLC (PSD-TX-1138-GHG)
Prevention of Significant Deterioration Permit
for Greenhouse Gas Emissions
Draft Permit Conditions

PROJECT DESCRIPTION

Following the construction authorized by this permit, CCI Corpus Christi, LLC (CCI) will construct a new condensate splitter facility and bulk petroleum terminal at a new Greenfield site near Corpus Christi, Texas. When complete, the new facility will consist of raw material storage tanks, two 50,000 barrel per day splitter trains, marine loading facilities, tank truck loading facilities, a flare, a marine vapor combustion unit, and emergency equipment. Each splitter train will have pre-heat and pre-flash drums, a charge heater, an auxiliary boiler to provide process steam, and a fractionation tower. Equipment common to both condensate splitter trains will include: a cooling tower to provide heat regulation of the units; a jet fuel treater to "finish" the diesel product before storage; a wastewater treatment unit to remove volatile organic compounds from wastewater and storm water before discharge to the Neches River; storage tanks to store the various grades of distilled product; and loading equipment necessary for shipping the product off-site. The company proposes to construct the facility in two phases. Phase I will include the condensate splitter with its associated equipment. Phase II will be the bulk terminal operations that will allow the company to gather raw condensate for shipping via marine vessel. The bulk terminal facility is expected to have a 500,000 barrel per day shipping capacity when at full capacity. The facility's emergency equipment include one diesel fired generator and two diesel fired firewater pumps that will be available for use in both Phase I and Phase II operations.

Incoming crude condensate will enter the facility via pipeline, rail, or barge and be stored for use in internal floating roof tanks. Each splitter will be fed crude condensate from the storage tanks and split it into several grades of salable petroleum product, each of which will be stored onsite in dedicated tanks. The condensate will pass through pre-heat and pre-flash drums before being heated in a charge heater and sent to a fractionation tower to distill off the different grades of product. The product slate proposed by CCI includes diesel, jet fuel, naphtha, gas oil and Y-grade liquids. Each product will be stored in dedicated tanks before exiting the site via truck, pipeline or barge. When the bulk terminal portion of the project is operational, the site will off load additional crude condensate from barge and pipeline sources, and store it in six storage tanks before loading it on marine ship vessels for export from the site. The ship and barge loading docks will use the marine vapor combustion unit to control volatile organic emissions from all loading operations.

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit.

FIN	EPN	Description
H-1	340-H1	Charge Preheater 1
H-2	350-H1	Charge Preheater 2
BL-1	240-B1	Boiler 1
BL-2	240-B2	Boiler 2
FL-1	330-FL-1	Flare
FL-MSS	330-FL-1	Flare-MSS
MVCU	150-FL2	Marine Vapor Combustion Unit
EMGEN	EMGEN	Emergency Generator
Multiple FINS	TK-MSS	Tank MSS (RTO emissions from tank degassing)
FW-1	FW-1	Firewater Pump 1
FW-2	FW-2	Firewater Pump 2
FUGS	FUGS	Fugitives
CWT	CWT	Cooling Tower
WWTP	WWTP	Wastewater Treatment Plant

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

The permit holder 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.

C. FACILITY OPERATION

At all times, including periods of startup, shutdown, and maintenance, the permit holder 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. 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. The permit holder shall notify EPA by mail within 48 hours following the discovery of any failure of air pollution control equipment, process equipment, or discovery of a failure of a process to operate in a normal manner, which results in increased 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., the permit holder 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. The permit holder 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

The permit holder shall construct this project in compliance with this PSD Permit, the application requesting this permit, the TCEQ PSD-TX-1388 and minor NSR permit No. 116072, and all other applicable federal, state, and local air quality regulations. This PSD permit does not release the permit holder 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
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
lb	Pound
LDAR	Leak Detection and Repair
MMBtu	Million British Thermal Units
MSS	Maintenance, Start-up and Shutdown
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
SCFH	Standard Cubic Feet per Hour
SCR	Selective Catalytic Reduction
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TPY	Tons per Year
USC	United States Code
VCU	Vapor Combustion Unit
VOC	Volatile Organic Compound
VRU	Vapor Recovery Unit

II. Annual Emission Limits

Annual emissions, in tons per year (TPY) calculated on a 365-day total, rolled daily, 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]		
H-1	340-H1	Charge Preheater 1	CO_2	70,803	70,889	Minimum thermal efficiency of 85%. See permit condition III.B.1.o.
			CH_4	1.47		
			N_2O	0.17		
H-2	350-H1	Charge Preheater 2	CO_2	70,803	70,889	Minimum thermal efficiency of 85%. See permit condition III.B.1.o.
			CH_4	1.47		
			N_2O	0.17		
BL-1	240-B1	Boiler 1	CO_2	16,619	16,640	Minimum thermal efficiency of 85%. See permit condition III.B.2.f.
			CH_4	0.34		
			N_2O	0.04		
BL-2	240-B2	Boiler 2	CO_2	16,619	16,640	Minimum thermal efficiency of 85%. See permit condition III.B.2.f.
			CH_4	0.34		
			N_2O	0.04		
FL-1	330-FL-1	Flare	CO_2	2,165	2,316	Good combustion practices. See permit condition III.B.4.
			CH_4	5.99		
			N_2O	No Numerical Limit Established[4]		
FL-MSS	330-FL-1	Flare-MSS	CO_2	368	369	Good combustion practices. See permit condition III.B.4.
			CH_4	0.04		
			N_2O	No Numerical Limit Established[4]		
MVCU	150-FL2	Marine Vapor Combustion Unit	CO_2	29,023	29,116	Good combustion practices. See permit condition III.B.3.
			CH_4	1.12		
			N_2O	0.22		
EMGEN	EMGEN	Emergency Generator	CO_2	122	123	Limit hours of operation and good combustion practices. See permit condition III.B.6.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
TK-MSS	Multiple FINS	Tank MSS (RTO emissions from tank degassing)	CO_2	37	37	Good combustion practices. See permit condition III.B.7.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
FW-1	FW-1	Firewater Pump 1	CO_2	41	41	Limit hours of operation and good combustion practices. See permit condition III.B.6.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
FW-2	FW-2	Firewater Pump 2	CO_2	41	41	Limit hours of operation and good
			CH_4	No Numerical Limit Established[4]		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
			N_2O	No Numerical Limit Established[4]		combustion practices. See permit condition III.B.6.
FUGS	FUGS	Fugitives	CH_4	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Implementation of LDAR Program. See permit condition III.B.3.
CWT	CWT	Cooling Tower	CH_4	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Implementation of LDAR Program. See permit condition III.B.8.
WWTP	WWTP	Wastewater Treatment Plant	CH_4	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Minimize VOC emissions. See permit condition III.B.9.
Totals[6]			**CO_2**	**206,641**	**CO_2e 207,771**	
			CH_4	**38**		
			N_2O	**0.64**		

1. Compliance with the annual emission limits (tons per year) is based on a 365-day total, rolled daily.
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 = 25 N_2O = 298
4. All values indicated as “No Numerical Limit Established” are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
5. Fugitive process emissions from EPN FUGS are estimated to be 15.9 TPY of CH_4, and 398 TPY CO_2e. Cooling Tower emissions from EPN CWT are estimated to be 1.84 TPY of CH_4 and 46 TPY CO_2e. Wastewater Treatment Plant emissions from EPN WWTP are estimated to be 9.04 TPY of CH_4 and 226TPY CO_2e.
6. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. These totals are given for informational purposes only and do not constitute emission limits.

III. SPECIAL PERMIT CONDITIONS

A. Phased Construction

This permit, when issued, allows CCI Corpus Christi (CCI), to construct a new 100,000 barrels per day (bbl/day) condensate splitter plant and bulk petroleum facility at its location in Nueces County, Texas. The company has proposed a two-phased approach to construction, separating the construction of a condensate splitter plant from the proposed bulk petroleum terminal operations. CCI will construct each phase concurrently with some shared equipment between the two phases. Phase I will be construction of the Condensate Splitter trains with associated equipment; phase II will be construction of the bulk terminal facility and loading operations.

Process Equipment	Included in Construction Phase
H-1 and H-2, Charge Heaters 1 and 2	I
BL-1 and BL-2, Auxiliary Boilers 1 and 2	I
FL-1 Flare	1 and II
FUG Fugitives	I and II
MVCU, Marine Vapor Combustion Unit	II
Emergency generator and Firewater Pump Engines, EMGEN, FW-1 and FW-2	I and II
MSS Maintenance, Startup, and Shutdown	I and II
Cooling Water Tower, CWT	I
Wastewater Treatment Plant, WWTP	I
Tank MSS (RTO emissions from tank degassing), TK-MSS	I and II

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

1. **Charge Heaters (EPNs: H-1 and H-2)**

   a. The permit holder shall calculate, on a daily basis, the amount of CO_2 emitted from the charge heaters (H-1 and H-2) in tons/yr using equation C-5 in 40 CFR Part 98, Subpart C, converted to short tons. Compliance shall be determined based on a 365-day rolling total basis. The permit holder will calculate CO2 emissions based on the proportion of natural gas and process gas combusted in the auxiliary boilers and the measured actual heat input (HHV) of each fuel.

   b. The permit holder shall calculate the CH_4 and N_2O emissions from the charge heaters (H-1 and H-2) on a 365-day rolling total basis. The permit holder 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-8 of 40 CFR Part 98 and the measured actual heat input (HHV), converted to short tons.

c. The permit holder shall calculate the CO_2e emissions on a 365-day rolling total 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 amended on November 29, 2013 (78 FR 71903).
d. Fuel for the heaters shall be limited to pipeline quality natural gas and a maximum 5% process gas. The fuel gross calorific value (GCV) [high heat value (HHV)] of the fuel shall be determined, at a minimum, quarterly by the procedures contained in 40 CFR 98.34(a)(6) and records shall be maintained of the semiannual fuel GCV for a period of five years. Upon request, the permit holder shall provide a sample and/or analysis of the fuel fired in the heaters or shall allow appropriate sampling of the heater fuel stream by EPA.
e. The permit holder shall measure and record the flow rate of the fuel combusted in the charge heaters (H-1 and H-2) using an operational totalizing fuel flow meter at each fuel inlet.
f. The permit holder shall perform cleaning of the heater's burner tips annually, at a minimum.
g. The permit holder shall install, operate, and maintain an automated air/fuel control system in the charge heaters (H-1 and H-2).
h. The permit holder shall calibrate and perform preventative maintenance on the air/fuel control analyzers once per quarter, at a minimum.
i. The permit holder shall utilize insulation materials (e.g. ceramic fiber blankets and Kaolite™) where feasible to reduce heat loss.
j. The permit holder shall install, operate, and maintain an O_2 analyzer on the charge heaters (H-1 and H-2).
k. Oxygen analyzers shall continuously monitor and record oxygen concentration in the charge heaters (H-1 and H-2). The permit holder shall reduce the oxygen readings to an averaging period of 6 minutes or less and record it at that frequency.
l. 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.
m. 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.
n. The annual average firing rate shall not exceed 137.4 MMBtu/hr/heater.
o. The permit holder shall be calculate a rolling 12-month average firing rate daily to demonstrate compliance with the firing rates in III.B.1.m.
p. The permit holder shall maintain a minimum overall thermal efficiency of 85% on a 12-month rolling average basis, calculated monthly, for the charge heaters (H-1 and H-2) excluding periods of start-up, shutdown, and malfunction.

q. The permit holder shall continuously monitor the charge heaters (H-1 and H-2) for exhaust temperature, input fuel temperature, and stack oxygen. Thermal efficiency for emission units will be calculated for each operating hour from these parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4^{th} ed.) Annex G.

r. 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 will be below the maximum rate and startups will be limited to 12 hours.

2. **Auxiliary Boilers (EPNs: BL-1 and BL-2)**

a. Fuel for the boilers shall be limited to pipeline quality natural gas and a maximum 5% process gas. The fuel gross calorific value (GCV) [high heat value (HHV)] of the fuel shall be determined, at a minimum, quarterly by the procedures contained in 40 CFR 98.34(a)(6) and records shall be maintained of the semiannual fuel GCV for a period of five years. Upon request, the permit holder shall provide a sample and/or analysis of the fuel fired in the heaters or shall allow appropriate sampling of the heater fuel stream by EPA.

b. The permit holder shall be measure and record the flow rate of the fuel combusted in the Auxiliary Boilers (BL-1 and BL-2) using an operational totalizing fuel flow meter at each fuel inlet.

c. The average annual firing rate for each Auxiliary Boiler shall not exceed 32.2 MMBtu/hr, calculated on a 12-month rolling average.

d. The permit holder shall be calculate a rolling 12-month average firing rate daily to demonstrate compliance with the firing rates in III.B.2.c.

e. The permit holder shall maintain a minimum overall thermal efficiency of 85% on a 12-month rolling average basis, calculated monthly, for the Auxiliary Boilers (BL-1 and BL-2), excluding periods of start-up, shutdown, and malfunction.

f. The permit holder shall continuously monitor the Auxiliary Boilers' (BL-1 and BL-2) exhaust temperature, input fuel temperature, and stack oxygen. Thermal efficiency for emission units will be calculated for each operating hour from these parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4th ed.) Annex G.

g. The permit holder shall measure and record the fuel flow rate using an inline flow meter and automatically record the data with a data acquisition and handling system.

h. The permit holder shall calibrate and perform preventative maintenance check of the fuel gas flow meters and document annually.

i. The permit holder shall measure and record the composition of the fuel gas firing each boiler.

j. The permit holder shall perform cleaning of the burner tips annually, at a minimum.

k. The permit holder shall perform cleaning of the convection section tubes annually, at a minimum.

l. The permit holder shall be calculate a rolling 12-month fuel usage record, including fuel composition, average hourly firing rate and the one-hour maximum firing rate, to demonstrate compliance with the conditions III.2. a., b., c., and d, above.
m. The permit holder shall install, operate and maintain an automated air/fuel control system.
n. The permit holder shall calibrate and perform preventative maintenance on the air/fuel control analyzers once per quarter, at a minimum.
o. The permit holder shall install, operate and maintain an O_2 analyzer on each boiler (BL-1 and BL-2).
p. Oxygen analyzers shall continuously monitor and record oxygen concentration in each boiler (BL-1 and BL-2). The permit holder shall reduce the oxygen readings to an averaging period of 6 minutes or less and record it at that frequency.
q. 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.
r. 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.
s. The permit holder shall calculate, on a daily basis, the amount of CO_2 emitted from the boilers (BL-1 and BL-2) in tons/yr using equation C-5 in 40 CFR Part 98, Subpart C, converted to short tons. Compliance shall be based on a 365-day rolling total basis. The permit holder will calculate CO2 emissions based on the proportion of natural gas and process gas combusted in the auxiliary boilers and the measured actual heat input (HHV) of each fuel.
t. The permit holder shall calculate the CH_4 and N_2O emissions on a 12-month rolling total basis. The permit holder shall determine compliance with the CH_4 and N_2O emissions limits contained in this permit 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.
u. The permit holder shall calculate the CO_2e emissions on a 12-month rolling total 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 amended on November 29, 2013 (78 FR 71903).

3. **Marine Vapor Combustion Unit (EPN: MVCU**)

a. The marine loading facilities will be equipped with a marine vapor combustion unit (MVCU).
b. The permit shall design the MVCU to combust VOC gases from the loading operations associated with marine vessels, including barges and marine shipping.
c. The MVCU shall have an initial stack test to verify the proper combustion chamber temperature to ensure a destruction and removal efficiency (DRE) of at least 99.8% for methane. During subsequent operations, if the waste gas flow rate

to the vapor combustor is greater than that recorded during the test period, the permit holder shall perform stack sampling at the new operating conditions within 120 days.

d. The permit holder shall be record natural gas fuel usage (in scf) for each burner using an operational non-resettable elapsed flow meter at the MVCU.
e. The permit holder shall measure and record the flow rate of the VOC containing gas combusted at the MVCU using an operational non-resettable elapsed flow meter.
f. The permit holder shall be calculate the VOC emissions resulting from loading activities using the physical and chemical properties of the material loaded. The permit holder shall use the data to calculate GHG emissions and show compliance with the limits specified in Table 1.
g. The permit holder shall calculate CO_2 emissions, on a monthly basis, using equation C-1 consistent with 40 CFR 98.33(a)(1)(i).
h. The permit holder shall perform periodic maintenance on the MVCU annually, at a minimum, or more often as recommended by the manufacturer specifications.
i. The permit holder shall maintain the combustion temperature above the one-hour average temperature maintained in the initial stack test. Prior to the stack test, the minimum combustion chamber temperature will be 1,400 ºF. Temperature monitoring of the MVCU combustion chamber will ensure proper operation.
j. The permit holder shall install and maintain a temperature recording device with an accuracy of the greater of ±0.75 percent of the temperature measured expressed in degrees Celsius or ±2.5ºC.
k. The permit holder shall continuously monitor and record the MVCU combustion chamber temperature when VOC containing gas vents to the MVCU from marine vessel loading activities. The temperature measurement devices shall reduce the temperature readings to an averaging period of 15 minutes or less and record it at that frequency.

4. **Flare (EPN: FL-1)**

a. The flare shall have a minimum destruction and removal efficiency (DRE) of 99% for methane based on flow rate and gas composition measurements as specified in 40 CFR Part 98, Subpart W, including 40 CFR § 98.233(n).
b. The flare shall only combust pipeline natural gas in the pilots during normal operations.
c. CO_2 emissions are calculated using equation Y-1 found in 40 CFR Part 98, Subpart Y, including 40 CFR § 98.253(b)(1)(ii)(A). CH_4 and N_2O emissions are calculated using equations Y-4 and Y-5 as found in 40 CFR Part 98, Subpart Y.
d. 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 or an approved alternate. An infrared monitor is equivalent to a thermocouple for flame monitoring purposes.

e. The on-line gas chromatograph (GC) analyzer shall have an on stream time of 95% on a semi-annual basis.

5. **Process Fugitives (EPN: FUG**)

The permit holder shall implement the TCEQ 28VHP leak detection and repair (LDAR) program for fugitive emissions of VOC as a surrogate for methane.[1]

6. **Emergency Generator and Firewater Pump Engines (EPNs: EMGEN, FW-1 and FW-2)**

   a. Emergency Generator and Firewater Pump engines are limited to 100 hours of non-emergency operation per year per engine. Compliance with the 100-hour non-emergency operational requirement is determined on a 12-month rolling basis.
   b. The engines will utilize No. 2 diesel as fuel.
   c. The engines shall meet the applicable monitoring and recordkeeping requirements as required in 40 CFR Part 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
   d. The permit holder shall install and maintain an operational non-resettable elapsed time meter for each engine.
   e. The permit holder shall maintain a file of all records, data measurements, reports and documents related to the operation of the engines, including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records relating to performance tests and monitoring of the emergency generator; natural gas usage, documents from the fuel supplier certifying the HHV of the fuel, and hours of operation required in Special Condition III.B.6.a; and all other information required by this permit recorded in a permanent form suitable for inspection. The permit holder must be retain the file for not less than five years following the date of such measurements, maintenance, reports, and/or records.

7. **Maintenance, Startup, and Shutdown (MSS) Activities (EPN: MSS)**

   a. Regenerative Thermal Oxidizer (RTO)
      i. The permit holder shall utilize a portable RTO to control MSS emissions associated with vacuum trucks, frac tanks, and any other process equipment not connected to the flare.

[1] The boilerplate special conditions for the TCEQ 28VHP LDAR program are available at http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/bpc_rev28vhp.pdf. These conditions will be included in the TCEQ issued NSR permit.

b. Flare
    i. The permit holder will use the flare (FL-1) to control MSS emissions from process unit turnarounds, storage tanks, process equipment, piping, air movers, vacuum trucks, and frac tanks when these emissions are not routed to a portable control device.
    ii. The flare will comply with the conditions of III.B.4, above, when controlling MSS emissions.

8. **Cooling Water Tower (EPN: CWT)**
    a. The permit holder will implement a Leak Detection and Repair Program consistent with the requirements of 40 CFR Part 63, Subpart F.
    b. Specifically, the permit holder shall comply with 40 CFR § 63.104 (c) through 63.104 (f).
        i. The permit holder shall monitor for the presence of total organic compounds or total organic carbon in the cooling water.

9. **Wastewater Treatment Plant**
    a. All process wastewater will be treated in an enclosed aerobic biologic treatment tank.
    b. The following equipment will be enclosed or appropriately sealed to prevent VOC emissions to the atmosphere:
        i. All wastewater and storm water sewers;
        ii. Each process drain, junction box, vent pipe, manhole, lift station;
        iii. Each oil-water separator.
    c. The oil-water separator vent must be routed to a control device.
    d. The permit holder will comply with 40 CFR Part 63, Subpart G standards for control of wastewater emissions.

C. Continuous Emissions Monitoring Systems (CEMS)

1. As an alternative to Special Condition III.B.1.a and III.B.2.t, the permit holder 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. If the permit holder adopts this alternative, the permit holder shall ensure that all required equipment is installed and all certification tests be completed on or before the earliest of 90 unit operating days or 180 calendar days after the date the unit commences operation.
3. The permit holder 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. The permit holder 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

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

    1. Operating hours for all air emission sources;
    2. Records of the fuel consumed by each source;
    3. The fuel usage for all combustion sources using continuous fuel flow monitors, (a computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer); and
    4. Semi-annual fuel sampling of natural gas, quarterly fuel sampling of recovered process fuel gas, or other frequencies as allowed by 40 CFR Part 98 Subpart C, including 40 C.F.R. § 98.34(b)(3).

B. The permit holder shall maintain and keep records of the monitoring results, as well as the repair and maintenance records in implementing the TCEQ 28VHP leak detection and repair program.

C. The permit holder 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 maintenance performed on any system or device at the facility; duration of startups and shutdowns; 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 permit holder must retain records for not less than five years following the date of such measurements, maintenance, reports, and/or records.

D. The permit holder shall maintain records of all GHG emission units and CO_2 emission certification tests and monitoring and compliance information required by this permit.

E. The permit holder shall maintain records and submit a written report of all excess emissions to EPA semi-annually, except when an applicable subpart requires more frequent reporting by or the Administrator, or authorized representative, on a case-by-case basis, determines more frequent reporting is necessary to 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:

    1. Time intervals, data and magnitude of the excess emissions, the nature and cause (if known), corrective actions taken, and preventive measures adopted;

2. Applicable time and date of each period during which the monitoring equipment was inoperative (monitoring down-time);
3. A statement in the report of a negative declaration, i.e., a statement when no excess emissions occurred or when the monitoring equipment has not been inoperative, repaired or adjusted;
4. Any failure to conduct any required source testing, monitoring or other compliance activities; and
5. Any violation of limitations on operation, including but not limited to restrictions on hours of operation of the emergency generator or fire pump.

F. Excess emissions means any period in which the facility emissions exceed a maximum emission limit set forth in this permit, a malfunction of an emission unit listed in the equipment list occurs that results in excess GHG emissions, or any other unauthorized GHG emissions occur.

G. 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.

H. 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 permit holder shall perform stack sampling and other testing to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the stacks of the Charge Heaters (H-1 and H-2), Auxiliary Boilers (BL-1and BL-2), Marine Vapor Combustor Unit (MVCU) and Flare (FL-1) 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 for the concentration of CO_2.

1. Multiply the CO_2 hourly average emission rate determined under maximum operating test conditions by 8,760 hours.
2. If the CO_2 emissions total calculated in V.A.1., above, 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 emissions 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 permit holder shall conduct an evaluation of the thermal efficiency of Charge Heater (H-1 and H-2), and the Auxiliary Boilers (BL-1 and BL-2) to verify compliance with minimal thermal efficiency requirements at III.B.1.o. and III.B.2.f, when performing testing as stated in V.A. above. The permit holder shall submit the results of the thermal efficiency evaluation to the EPA within 30 days of testing.

C. Within 60 days after achieving the maximum production rate at which the affected facility will operate, but not later than 180 days after initial startup of the facility, the permit holder must conduct performance test(s) and furnish a written report of the performance testing results to the EPA. EPA may require additional sampling.

D. The permit holder 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 permit holder shall conduct the performance test in accordance with the submitted protocol, and any changes required by EPA.

E. The permit holder shall conduct performance testing using flow rates that are comparable to the normal operating flow rates.

F. The permit holder shall conduct fuel sampling for the flare (FL-1) in accordance with 40 CFR Part 98.

G. Flare compliance determinations shall be made following the requirements in 40 CFR 65.147(b)(3)(i) through 65.147(b)(3)(iv).

H. The MVCU will be stack tested under TCEQ Permit No. 116072. Stack testing will establish the minimum combustion chamber temperature for the MVCU. The permit holder shall perform stack testing initially, and within 120 days of a process flow change. CCI is to provide EPA with a copy of the stack testing results.

I. The permit holder shall conduct performance tests under 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.

J. 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.

K. 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.

L. Unless otherwise specified, each performance test shall consist of three separate runs using the applicable test method. The permit holder shall conduct each run 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.

M. The permit holder shall conduct emissions testing, as outlined above, within 120 days of a process flow change, to verify continued performance at permitted emission limits.

N. The permit holder shall conduct emissions testing, as outlined above, every five years, plus or minus 6 months, of when the previous performance test was performed, or within 180 days after the issuance of a permit renewal, whichever comes later, to verify continued performance at permitted emission limits.

VI. Agency Notifications

The permit holder 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

The permit holder 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