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-101199-GHG
PERMITTEE:	KM Liquids Terminals LLC 1001 Louisiana St, Suite 1000 Houston, TX 77002
FACILITY NAME:	Condensate Splitter Plant Galena Park Terminal
FACILITY LOCATION:	906 Clinton Drive Galena Park, TX 77547

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 KM Liquids Terminals LLC (KMLT) for Greenhouse Gas (GHG) emissions. The Permit applies to the construction of a new condensate splitter plant and modifications to existing equipment at their existing facility located in Galena Park, Texas.

KM Liquids Terminals 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) Non-attainment New Source Review (NNSR) permit No. N158 and minor New Source Review (NSR) permit No. 101199. 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 KMLT 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)(3), this PSD Permit becomes effective immediately upon issuance of this final decision.

Wren Stenger

Wren Stenger, Director
Multimedia Planning and Permitting Division

5/22/13
Date

KM Liquids Terminals LLC (PSD-TX-101199-GHG)
Prevention of Significant Deterioration Permit
For Greenhouse Gas Emissions
Draft Permit Conditions

PROJECT DESCRIPTION

Following the construction authorized by this permit, the facility will add a new condensate splitter plant consisting of two trains at the Galena Park Terminal in Galena Park, Texas. The Galena Park 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 existing facility consists of various storage tanks and associated piping, loading, and control equipment. The condensate splitter plant will be constructed in two 50,000 bbl/day phases. The condensate splitter plant will consist of two trains and will include a stabilization column, a main fractionation column, heaters, flare, and storage tanks. The process will take hydrocarbon condensate material and process it to obtain products suitable for commercial use, which include Y-grade liquids, light naphtha, heavy naphtha, kerosene, and distillate product for sale to customers.

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit.

FIN	EPN	Description
F-101 F-201	F-101 F-201	2 Hot Oil Heaters (Combustion Unit). Each unit has a maximum design heat input rate of 247 MMbtu/hr, and is fired with natural gas.
FL-101	FL-101	Flare (Combustion Unit). Used for control of Maintenance, Startup, and Shutdown (MSS) emissions and for emergency releases.
SD-4-VCU VCU-1A VCU-1B VCU-2A VCU-2B VCU-2C	SD-4-VCU VCU-1A VCU-1B VCU-2A VCU-2B VCU-2C	Marine Vapor Combustion Unit (VCU) (Combustion Unit)
EGEN-1	EGEN-1	Emergency Generator (Combustion Unit). A natural gas fired emergency generator engine used for emergency backup power.
MSS	MSS	Maintenance, Startup, and Shutdown (MSS) (Combustion Units)
FUG	FUG	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 NNSR Permit N158 and minor NSR permit No. 101199, 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
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]		
F-101	F-101	Naphtha Stabilizer Hot Oil Heater - Train 1	CO_2	116,083	116,191	Minimum thermal efficiency of 85%. See permit condition III.B.1.o.
			CH_4	2.2		
			N_2O	0.2		
F-201	F-201	Naphtha Stabilizer Hot Oil Heater - Train 2	CO_2	116,083	116,191	Minimum thermal efficiency of 85%. See permit condition III.B.1.o.
			CH_4	2.2		
			N_2O	0.2		
FL-101	FL-101	Flare	CO_2	78	78	Good combustion practices. See permit condition III.B.2.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
SD4-VCU VCU-1A VCU-1B VCU-2A VCU-2B VCU-2C	SD4-VCU VCU-1A VCU-1B VCU-2A VCU-2B VCU-2C	Marine Loading Vapor Combusting Units	CO_2	3,042	3,051	Maintain a minimum combustion temperature as determined by stack testing. See permit condition III.B.4.i.
			CH_4	0.12		
			N_2O	0.02		
EGEN-1	EGEN-1	Emergency Generator	CO_2	309	309	Limit hours of operation and good combustion practices. See permit condition III.B.5.
			CH_4	0.01		
			N_2O	No Numerical Limit Established[4]		
MSS	MSS	MSS Emissions from Flare and Portable Control Unit	CO_2	7,561	7,561	Good combustion practices. See permit condition III.B.6.
			CH_4	0.01		
			N_2O	No Numerical Limit Established[4]		
019-FUG	019-FUG	Process Fugitive Emissions	CH_4	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Implementation of LDAR Program. See permit condition III.B.3.
Totals[6]			**CO_2**	**243,156**	**CO_2e 243,545**	
			CH_4	**12.3**		
			N_2O	**0.42**		

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 only from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 21, N_2O = 310
4. All values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
5. Fugitive process emissions from EPN 019-FUG are estimated to be 7.8 TPY of CH_4, and 164 TPY 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

KMLT proposes to construct the proposed condensate splitter in two phases. The condensate splitter will consist of two 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. The table below identifies under which phase of construction each emission point will be constructed. Train 1 will be constructed in Phase 1 and Train 2 will be constructed in Phase 2.

Process Equipment	Included in Construction Phase
F-101 Hot Oil Heater Train 1	1
F-201 Hot Oil Heater Train 2	2
FL-101 Flare	1
FUG Fugitives	1 and 2
Tank Truck Loading/Unloading	1 and 2
MSS Maintenance, Startup, and Shutdown	1 and 2
Modification of Marine Vessel VCUs	1

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

1. Hot Oil Heaters (EPNs: F-101 and F-201)

    a. Permittee shall calculate, on a daily basis, the amount of CO_2 emitted from combustion 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.
    b. Permittee shall calculate the CH_4 and N_2O emissions on a 365-day rolling total 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-8 of 40 CFR Part 98 and the measured actual heat input (HHV), converted to short tons.
    c. Permittee 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 published on October 30, 2009 (74 FR 56395).
    d. Fuel for the heaters shall be limited to pipeline quality natural gas and produced off gas. 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.

e. 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.
f. Permittee shall perform cleaning of the burner tips, at a minimum of, annually.
g. Permittee shall install, operate, and maintain an automated air/fuel control system.
h. Permittee shall calibrate and perform preventative maintenance on the air/fuel control analyzers once per quarter, at a minimum.
i. Permittee shall utilize insulation materials (e.g. ceramic fiber blankets and Kaolite™) where feasible to reduce heat loss.
j. Permittee shall install, operate, and maintain an O_2 analyzer on the hot oil heaters (F-101 and F-201).
k. Oxygen analyzers shall continuously monitor and record oxygen concentration in the hot oil heaters (F-101 and F-201). It shall reduce the oxygen readings to an averaging period of 15 minutes or less and record it at that frequency.
l. 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, with the following exception: a relative accuracy test audit is not required once every four quarters (i.e., two successive semiannual CGAs may be conducted).
m. The annual average firing rate shall not exceed 225 MMBtu/hr.
n. A rolling 12-month average firing rates shall be calculated daily to demonstrate compliance with the firing rates in III.B.1.m.
o. 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 (F-101 and F-201) excluding periods of start-up, shutdown, and malfunction.
p. The hot oil heaters (F-101 and F-201) will be continuously monitored 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.
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 and startups will be limited to 12 hours.

2. Flare (EPNs: FL-101)

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 record the molecular weight and mass flow rate of the flare gas.
b. The flare shall be air assisted.

c. The flare shall have a minimum destruction and removal efficiency (DRE) of 98%.based on flowrate and gas composition as specified in 40 CFR Part 98 Subpart W § 98.233(n).
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. 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.

3. Process Fugitives (EPNs: FUG)

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

4. Marine Vessel Loading (EPNs: SD4-VCU, VCU-1A, VCU-1B, VCU-2A, VCU-2B, and VCU-2C)

a. The existing marine loading is equipped with six vapor combustion units (SD4-VCU, VCU-1A, VCU-1B, VCU-2A, VCU-2B, and VCU-2C). GHG emissions from the VCUs result from fuel gas combustion (pipeline quality natural gas) and VOC containing gas combustion (gas from the loading of marine vessels associated with the facilities included in this permit).
b. The vapor combustion unit is designed to combust VOC gases from the loading operations associated with marine vessel.
c. The VCU 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, stack sampling shall be performed at the new operating conditions within 120 days.
d. For burner combustion, natural gas fuel usage (scf) is recorded using an operational non-resettable elapsed flow meter at the VCU.
e. The flow rate of the VOC containing gas combusted shall be measured and recorded using an operational non-resettable elapsed flow meter at the VCU.

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

f. VOC emissions resulting from loading activities shall be calculated using the physical and chemical properties of the material being loaded. The data will be used to calculate GHG emissions to show compliance with the limits specified in Table 1.
g. Permittee shall calculate CO_2 emissions, on a monthly basis, using equation C-1 consistent with 40 CFR Part 98, Subpart C [98.33(a)(1)(i)].
h. Periodic maintenance will help maintain the efficiency of the VCU and shall be performed at a minimum annually or more often as recommended by the manufacturer specifications.
i. The Permittee shall maintain the combustion temperature above the one hour average temperature maintained in the initial stack test, as required by the TCEQ NSR Permit No. 101199, based on the minimum chamber temperature on a 15 minute average. Prior to the stack test, the minimum combustion chamber temperature will be 1,400 ^{o}F. Temperature monitoring of the VCU combustion chamber will ensure proper operation.
j. 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 Celsius or ±2.5ºC.
k. The VCU combustion chamber temperature shall be continuously monitored and recorded when VOC containing gas is directed to the VCU 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.

5. Emergency Generator (EPN: EGEN-1)

a. The Emergency Generator is limited to 500 hours of non-emergency operation per year. Compliance with the 500 hour non-emergency operational requirement is determined on a 12 month rolling basis.
b. The Emergency Generator will utilize pipeline quality natural gas as fuel.
c. The Emergency Generator 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. Permittee shall install and maintain an operational non-resettable elapsed time meter for the Emergency Generator.
e. Permittee shall maintain a file of all records, data measurements, reports and documents related to the operation of the Emergency Generator, 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.5.b; and all other information required by this permit recorded in a permanent form suitable for inspection. The file must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.

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

   a. Vapor Recovery Units (VRU)
      i. A portable vapor recovery unit (VRU) shall be utilized to control MSS emissions associated with vacuum trucks, frac tanks, and any other process equipment that is not connected to the flare or portable vapor combustion unit.
   b. Flare
      i. The flare (FL-101) will be used 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 (vapor recovery unit or vapor combustion unit) provided by a contractor.
      ii. The flare will comply with the conditions of III.B.2. above when controlling MSS emissions.
   c. Vapor Combustion Units (VCU) and Internal Combustion Engines (ICE)
      i. The VCUs/ICEs are portable units owned by a third party contracted to perform services.
      ii. The VCUs/ICEs will be used 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 the process flare (FL-101) or vapor recovery unit.

C. Continuous Emissions Monitoring Systems (CEMS)

1. As an alternative to Special Condition III.B.1.o. 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. If this alternative is adopted, 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
    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 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 F-101, F-201, SD4-VCU, VCU-1A, VCU-1B, VCU-2A, VCU-2B, and VCU-2C 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. For the Hot Oil Heaters calculate the CO_2 hourly average emission rate determined under maximum operating test conditions, convert to lbs of CO_2/MMBtu. Use the following equation to calculate the annual emissions.

$$CO_2\ TPY = 2 * 225 \frac{MMBtu}{hr} * 8{,}760 \frac{hr}{year} * lb \frac{CO_2}{MMBtu}$$

Where:

225 MMBtu/hr = is the design annual average furnace firing rate upon which the emissions in Table 1 were based on.

lb CO_2/MMBtu = calculated from V.A.

2. For the marine loading VCUs calculate the CO_2 hourly average emission rate determined under maximum operating test conditions, convert to lbs of CO_2/MMBtu. Use the following equation to calculate the annual emissions.

$$CO_2\,TPY = 41{,}514\frac{MMBtu}{yr} * lb\frac{CO_2}{MMBtu}$$

Where:

41,514 MMBtu/yr = is the marine loading emissions cap design annual heat input rate upon which the emissions in Table 1 were based on.
lb CO_2/MMBtu = calculated from V.A.

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 (F-101 and F-201) to verify compliance with minimal thermal efficiency requirements at III.B.1.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.

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 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 FL-101 (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 65 sections 65.147(b)(3)(i) through 65.147(b)(3)(iv).

H. The marine vessel vapor combustion will be stack tested under TCEQ Permit No. 101199. Stack testing will establish the minimum combustion chamber temperature for the VCUs. Stack testing will be performed initially and within 120 days of a process flow change. KMLT is to provide EPA with a copy of the stack testing results.

I. 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.

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. 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. Emissions testing, as outlined above, shall be performed within 120 days of a process flow change, 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:

Multi Media 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