AMENDED
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-1292-GHG
PERMITTEE:	Occidental Chemical Corporation P.O. Box CC Ingleside, TX 78362
FACILITY NAME:	Ingleside Chemical Plant
FACILITY LOCATION:	4133 Hwy 361 Gregory, TX 78359

Pursuant to the provisions of the Clean Air Act (CAA), Subchapter I, Part C (42 U.S.C. § 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 an amended *Prevention of Significant Deterioration* (PSD) permit to the Occidental Chemical Corporation (OxyChem) for Greenhouse Gas (GHG) emissions. The Permit authorizes the construction of a new natural gas liquids (NGL) fractionation plant at the existing Ingleside Chemical Plant located in Gregory, Texas. This amended PSD Permit revises the PSD permit issued to OxyChem on January 10, 2014, with the revisions applicable immediately.

OxyChem is authorized to construct a new NGL fractionation plant at the existing chemical plant as described herein, in accordance with the permit application and accompanying plans, 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-1292. 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 CAA. This PSD Permit does not relieve OxyChem 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

4/16/14

Date

Occidental Chemical Corporation
Ingleside Chemical Plant (PSD-TX-1292-GHG)
Prevention of Significant Deterioration Permit
For Greenhouse Gas Emissions
Final Permit Conditions

PROJECT DESCRIPTION

Pursuant to the provisions of this permit, the facility will construct a new NGL fractionation plant at the existing Ingleside Chemical Plant in San Patricio County, Texas. The NGL fractionation plant will receive NGL by pipeline and will fractionate these liquids into commercial grade products (ethane, propane, butanes, and natural gasoline), which will be stored on-site (except for ethane, which will be routed to the pipeline without storage), and then transferred to markets by various means, including pipeline, tank trucks, rail cars, and barges. The new NGL fractionation plant will process approximately 87,000 barrels per day.

Process facilities receive NGL by pipeline and separate these liquids by distillation into four products: ethane, propane, mixed butanes, and natural gasoline (higher molecular weight hydrocarbons in the NGL after ethane, propane and butanes are removed). Distillation concentrates sulfur compounds found in the NGL feed in the mixed butanes and natural gasoline fractions. A dedicated process unit converts these sulfur compounds to disulfide oil to be blended with the natural gasoline.

Each distillation process in the NGL fractionation facility operates under pressure. Each distillation process includes a fractionation column, a reboiler to provide heat for the distillation of liquids, and a means to condense the vaporized fraction. The fractionation columns of the NGL fractionation facility use steam to supply heat to the process. Steam is supplied from both an adjacent existing natural gas fired cogeneration unit and from new steam generation facilities installed with the NGL plant. Reboilers are used on each fractionation column to exchange heat from steam with the process fluids. Steam from the thermal oxidizers and the existing cogeneration units provide heat to the reboiler, which is a non-combusting unit with no GHG emissions. The reboiler is used to vaporize process fluids in the bottom of a fractionation column. Cooling and condensing for the fractionators is supplied from re-circulating propane refrigerant and re-circulating cooling water, both supplied from new facilities to be installed at the NGL fractionation site.

Carbon dioxide and other acid gases present in the NGL feed are extracted by a re-circulating amine stream. Vent gases from regeneration of these amines are routed to a thermal oxidizer for destruction of organic compounds. Water and some aromatic hydrocarbons in the NGL feed are extracted by a re-circulating glycol stream. Vent gases from regeneration of glycol are also routed to a thermal oxidizer for destruction of organic compounds. Small amounts of liquid waste created in the re-circulating amine and glycol streams are removed by filters and are discarded as solid wastes along with the filter media.

Sulfur-containing organic compounds present in the NGL feed are concentrated by fractionation into the materials fed to the debutanizer. Sulfur compounds present in the overhead product (mixed butanes) and bottom product (natural gasoline) from the debutanizer are converted to disulfide oils that are blended with the natural gasoline. These conversion/extraction processes create vapor discharges that are routed to the thermal oxidizers and sulfide-rich aqueous caustic streams. These sulfide-rich caustic streams are treated to convert sulfides to disulfides and then regenerated to remove the disulfide oil after which the regenerated caustic stream is recycled to butane and gasoline sulfur removal units. A small stream of sulfide caustic will be periodically removed as a liquid waste stream, which will be disposed of off-site in accordance with applicable requirements.

Stored liquid products are transferred to markets by pipeline, by tanker truck, by rail car and by barge. Propane, butane, and natural gasoline products that do not meet specifications are stored temporarily on-site until they can be reprocessed. All non-pressurized storage tanks at the site handling VOC materials with a vapor pressure greater than 0.5 psia are vented to the thermal oxidizers for control. Also, non-pressurized loading vapors from barge, rail car, and truck loading will be controlled by the thermal oxidizers.

Process wastewater from NGL fractionators and product storage, transfer, and loading facilities is collected and transferred in closed systems to a wastewater storage tank. Collected wastewater is steam-stripped to remove organic compounds with the overhead vapor routed to the thermal oxidizer. The stripped wastewater is pumped to a biological treatment system at the existing plant. Vapors from process wastewater collection drain tanks, separator vents, and the spent caustic oxidizer vent are routed to the thermal oxidizers.

Fugitive emissions of greenhouse gas (GHG) pollutants, including CO_2 and methane, may result from piping equipment leaks. The piping components that may leak include valves, flanges, pump seals, etc. OxyChem will implement the TCEQ 28MID Leak Detection and Repair (LDAR) program for the Ingleside Chemical Plant site.

The site has two existing cogeneration units (CG-1 and CG-2). The existing cogeneration units are not being modified. They are permitted by TCEQ under permit Nos. 35335 and PSD-TX-880. The cogeneration units will provide steam and energy to the new NGL fractionation facility. Currently, the excess energy produced by the cogeneration plants is sent to the grid. The cogeneration units will not have an increase in their currently permitted firing rates.

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit.

Emission Unit Id. No.	Description
NGL-1 NGL-2	Two Thermal Oxidizers (Combustion Units) for control of waste gas streams and to supply process heat.
NGL-3	Flare (Combustion Unit) used for emergency situations
NGL-4	NGL Cooling Tower
NGL-5	NGL Process Area Fugitives
NGL-10	Emergency Generator Engine (Combustion Unit) 1,200 HP diesel-fired
NGL-11 NGL-12 NGL-13 NGL-14	Four Firewater Pump Engines (Combustion Units) 500 HP each, diesel-fired

I. GENERAL PERMIT CONDITIONS

A. PERMIT EXPIRATION

As provided in 40 CFR § 52.21(r)(2), 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)(2), 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.C.

C. FACILITY OPERATION

At all times, including periods of startup, shutdown, and maintenance (SSM), Permittee shall 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 of the discovery of any failure of air pollution control equipment, process equipment, or a process to operate in a normal manner that results in an increase in GHG emissions above the allowable emission limits stated in Section II of this permit.

2. Within 10 days of the restoration of normal operations after any failure described in Section 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 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 and operate this project in compliance with this PSD Permit, the application on which this permit is based, the TCEQ PSD Permit PSD-TX-1292 (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 CAA.

I. ACRONYMS AND ABBREVIATIONS

BACT	Best Available Control Technology
bbl	Barrel
Btu	British Thermal Unit
CAA	Clean Air Act
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CGA	Cylinder Gas Audit
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
DRE	Destruction and Removal Efficiency
dscf	Dry Standard Cubic Foot
EPN	Emission Point Number
FR	Federal Register
GHG	Greenhouse Gas
gr	Grains
HHV	High Heating Value
hp	Horsepower
Hr	Hour
IFR	Internal Floating Roof
LDAR	Leak Detection and Repair
LHV	Lower Heating Value
Lb	Pound
MMBtu	Million British Thermal Units
MMSCFD	Million Standard Cubic Feet per Day
MSS	Maintenance, Start-up and Shutdown
NGL	Natural Gas Liquids
N_2O	Nitrous Oxides
NSPS	New Source Performance Standards
PSD	Prevention of Significant Deterioration
QA/QC	Quality Assurance and/or Quality Control
RATA	Relative Accuracy Test Audit
SCFH	Standard Cubic Feet per Hour
SCR	Selective Catalytic Reduction
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TO	Thermal Oxidizer
TPY	Tons per Year
USC	United States Code

II. Annual Facility Emission Limits

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

Table 1. Facility Emission Limits[1]

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
NGL-1	NGL-1	Thermal Oxidizer	CO_2	41,450	41,579	Minimum firebox temperature of 1,400 °F with Flue gas exhaust < 550°F on a 365-day rolling average basis. See permit condition III.A.1.h. - i.
			CH_4	1.6		
			N_2O	0.3		
NGL-2	NGL-2	Thermal Oxidizer	CO_2	41,450	41,579	Minimum firebox temperature of 1,400 °F with Flue gas exhaust < 550°F on a 365-day rolling average basis. See permit condition III.A.1.h. - i.
			CH_4	1.6		
			N_2O	0.3		
NGL-3	NGL-3	NGL Emergency Flare	CO_2	1,000	1,000	Flare will meet the requirements of 40 CFR 60.18. See permit condition III.A.2.g.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
NGL-4	NGL-4	NGL Cooling Tower	CO_2	208	208	Monitor the feed water and make-up water. See permit condition III.A.3.b. through d.
NGL-5	NGL-5	NGL Process Area Fugitives	CO_2	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Implementation of LDAR Program. See permit condition III.A.4.c.
			CH_4	No Numerical Limit Established[5]		
NGL-10	NGL-10	Emergency Generator Engine	CO_2	34	34	Good combustion practices. See permit conditions III.A.5.b. and III.A.5.d - f.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
NGL-11 NGL-12 NGL-13 NGL-14	NGL-11 NGL-12 NGL-13 NGL-14	Firewater Pump Engines	CO_2	16[6]	64[6]	Good combustion practices. See permit conditions III.A.5.c. through f.
			CH_4	No Numerical Limit Established[4,6]		
			N_2O	No Numerical Limit Established[4,6]		
Totals[7]			**CO_2**	**84,206**	**CO_2e 84,473**	
			CH_4	**3.6**		
			N_2O	**0.6**		

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, including MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298
4. No numerical limit is established as the estimated 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 EPN NGL-5 are estimated to be 0.43 TPY CO_2, 0.36 TPY of CH_4 and 9.4 TPY CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
6. The GHG mass basis TPY value is for each firewater pump engine. The CO_2e TPY limit is for all 4 combined.
7. 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. Emission Unit Work Practice Standards, Operational Requirements, and Monitoring

1. Thermal Oxidizers (NGL-1 and NGL-2)

a. The thermal oxidizer shall be designed to combust non-condensable waste gases from the NGL fractionation process and shall have a maximum fuel rating of 60 MMBtu/hr when firing natural gas and waste gas.
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) shall be monitored and recorded by the Distributive Control System (DCS) and a data historian will maintain the data.
d. The flow rate of the oxidizer flue gas shall be measured and recorded by the DCS.
e. Oxidizer flue gas shall be sampled and analyzed on a quarterly basis for composition. The sampled data will be used to calculate GHG emissions to demonstrate 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)].
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 1,400 ºF at all times when processing waste gases in the thermal oxidizer. 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.
i. The thermal oxidizer exhaust gas temperature monitored at the exhaust stack shall be limited to less than 550ºF on a 365-day rolling average basis. The thermal oxidizers' exhaust temperature shall be continuously monitored and recorded when waste gas is directed to the thermal oxidizers. The temperature measurement devices shall reduce the temperature readings to an averaging period of 6 minutes or less and record it at that frequency.
j. Flow and temperature measurement devices shall be calibrated, at a minimum, on a biannual basis.
k. The Permittee shall install and operate oxygen analyzers on the exhaust stack to continuously monitor and record oxygen concentration when waste gas is directed to the thermal oxidizers. Oxygen readings shall be reduced to an averaging period of 6 minutes or less and recorded 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.

2. NGL Emergency Flare (NGL-3)

a. The flare shall have a minimum destruction and removal efficiency (DRE) of 98% based on flowrate and gas composition measurements as specified in 40 CFR Part 98 Subpart W § 98.233(n).
b. The flare shall be designed and operated for emergency use and for periods of time when both thermal oxidizers are out of service for inspection and maintenance.
c. The flare shall only combust pipeline natural gas in the pilots during normal operations. The only emissions authorized by this permit are the combustion of natural gas during normal operation.
d. The Permittee shall record the time, date, and duration of each emission event and each thermal oxidizer maintenance event as described in condition III.A.2.b. These records must be kept for five years following the date of each event.
e. The flare shall be equipped with a flare gas flow meter and temperature monitor. Flow and temperature measurement devices shall be calibrated, at a minimum, on a biannual basis.
f. CO_2 emissions shall be calculated using equation Y-1 in 40 CFR Part 98 Subpart Y, §98.253(b)(1)(ii)(A). CH_4 and N_2O emissions shall be calculated using equations Y-4 and Y-5 in 40 CFR Part 98 Subpart Y. As an alternative to the carbon content monitored required in 98.253(b)(1)(ii)(A), carbon content determined by engineering estimates, as allowed in paragraph (iii)(A) may be used with equation Y-3.
g. 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 considered equivalent to a thermocouple for flame monitoring purposes.

3. Cooling Tower (NGL-4)

a. The cooling tower water supply shall be equipped with continuous pH and conductivity monitoring systems.
b. The pH analyzer shall be calibrated on a weekly basis using 3 points. The calibration slope shall be 90% or greater and corrected for temperature. Failure to maintain an appropriate slope shall require the replacement of the pH probe or membrane.
c. The conductivity meter shall be calibrated on a weekly basis using at least 2 calibration points bracketing the expected value for the cooling tower feed water. It shall measure the specific conductivity in µS/cm.

d. Laboratory instruments shall be utilized when the on-line analyzers are out of service.
e. The Permittee shall, on a monthly basis, test the cooling tower make-up water for alkalinity following Method 2320B from the *Standard Methods for the Examination of Water and Wastewater*. The bicarbonate value from this analysis will be used to calculate CO_2 emissions from the cooling tower using the following equations.

$$HCO_3\ loading\left(\frac{lb}{hr}\right) = Makeup\ Water\left(\frac{lb}{hr}\right) \times bicarbonate\ (ppm)$$

$$CO_2\left(\frac{lb}{hr}\right) = HCO_3\left(\frac{lb}{hr}\right) \times 44\ \times \left(\frac{1}{61}\right)$$

Where:
44 = Molecular Weight of CO_2
61 = Molecular Weight of HCO_3

$$CO_2\,TPM\ = CO_2\left(\frac{lb}{hr}\right) \times 2{,}000\,\frac{lb}{ton} \times xx\ hr/month$$

f. Compliance with the Annual Emission Limit shall be demonstrated on a 12-month total, rolling monthly.

4. NGL Process Area Fugitives (NGL-5)

a. The Permittee shall install rupture discs beneath relief valves discharging to the atmosphere, where feasible.
b. The Permittee shall install barrier seal systems on pumps and compressors in VOC service, where feasible.
c. The Permittee shall implement the TCEQ 28MID Leak Detection and Repair (LDAR) program for fugitive emissions of methane.

5. Emergency Generator Engine (NGL-10) and Firewater Pump Engines (NGL-11, NGL-12, NGL-13, and NGL-14)

a. Each emergency engine shall be diesel fired and meet the requirements of 40 CFR Part 60 Subpart IIII.
b. The emergency generator shall have a power output not to exceed 1,200 HP.
c. The firewater pump engines shall each have a power output not to exceed 500 HP.
d. The Permittee shall change the oil and filter every 500 hours of operation or annually, whichever occurs first.
e. The Permittee shall inspect all hoses and belts every 500 hours of operation or annually, whichever occurs first and replace worn parts as needed.

f. The Permittee shall inspect the air cleaner every 1,000 hours of operation or annually, whichever occurs first and replace worn parts as needed.
g. The emission limits in Table 1 are based on each emergency engine operating 52 hours a year for maintenance and testing, excluding initial stack testing.
h. 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)(2)(i).

B. Continuous Emissions Monitoring Systems (CEMS)

1. As an alternative to Special Condition III.A.1.i, the 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. The 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. The 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 Requirements

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

a. Operating hours for all air emission units;
b. The natural gas fuel usage for all combustion units, 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, quarterly fuel sampling of waste gas.

B. The Permitee shall implement the TCEQ 28MID leak detection and repair (LDAR) program and keep records of the monitoring results, as well as the repair and maintenance records.
C. At least once per quarter, the Permittee will obtain an updated analysis of the vent gases exhausted from the thermal oxidizers. This analysis will be considered to be

representative of the vent gas streams for the quarter during which it was taken and will be used to estimate the thermal oxidizer emissions.

D. For each calendar month, the Permittee will calculate the 12 month rolling GHG emission rates for comparison to the emission limits in Table 1.

E. The Permittee shall also maintain site-specific procedures for best/optimum maintenance practices and vendor-recommended operating procedures and O&M manuals for all air emission units. These procedures must be maintained on-site.

F. The Permittee shall maintain a file of 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; the occurrence and duration of any startup, shutdown, or malfunction, annual tuning of heaters; all records relating to performance tests and monitoring of combustion equipment; calibrations, checks, duration of any periods during which a monitoring device is inoperative, and corresponding emission measurements; 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.

G. The 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:

    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; that is; a statement when no excess emissions occurred or when the monitoring equipment has not been inoperative, repaired or adjusted; and
    4. Any failure to conduct any required source testing, monitoring, or other compliance activities.

H. Excess emissions shall be defined as any period in which the facility emission exceeds an emission limit set forth in this permit.

I. 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.

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

V. **Performance Testing Requirements**:

A. The holder of this permit shall perform an initial stack test to establish the actual quantities of CO2 being emitted into the atmosphere from emission units NGL-1 and NGL-2, 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 for the concentration of CO_2 for the thermal oxidizers.

   1. Multiply the CO_2 hourly average emission rate determined under maximum operating test conditions by 8,760 hours.
   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. 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.

C. 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.

D. Performance testing must be conducted using a maximum rate of operation.

E. Fuel sampling for emission units NGL-1 and NGL-2 shall be conducted in accordance with 40 CFR Part 98 Subpart C.

F. The Permittee shall perform initial performance demonstration testing of the thermal oxidizers 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 at a minimum combustion chamber temperature of 1,300 °F.

G. 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 used to demonstrate compliance, and at all times greater than 1,300 °F.

H. 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.

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

J. The Permittee 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 Permittee 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.

M. During subsequent operations, if the maximum hourly production rate is greater than that recorded during the initial test period, stack sampling shall be performed at the new operating conditions within 120 days, 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: 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