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-1302-GHG
PERMITTEE:	Freeport LNG Development, L.P. 333 Clay Street, Suite 5050 Houston, TX 77002
FACILITY NAME:	Freeport LNG Liquefaction Project
PRETREATMENT FACILITY LOCATION:	CR 690, approximately 0.25 miles north of the intersection of CR690 and CR891 Freeport, TX 77541
LIQUEFACTION PLANT LOCATION:	1500 Lamar Street Quintana, TX 77541

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 Freeport LNG Development, L.P. (Freeport LNG) for Greenhouse Gas (GHG) emissions. The Permit for the Freeport LNG Liquefaction Project applies to the construction of a natural gas liquefaction plant contiguous to Freeport LNG's existing Liquefied Natural Gas Terminal facility on Quintana Island and a natural gas pretreatment facility to be located approximately 3.5 miles from the Quintana Island Terminal, both in Brazoria County, Texas.

Freeport LNG is authorized to construct a new liquefaction plant and pretreatment facility 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-1302 and Nonattainment New Source Review (NNSR) permit No. N170 for the Pretreatment Facility and permit No. PSD-TX-1282 and N150 for the Liquefaction Plant. 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 Freeport LNG of the responsibility to comply with any other applicable provisions of the CAA (including applicable implementing regulations in 40 CFR Parts 51, 52, 60, 61, 72 through 75, and 98) or other federal and state requirements (including the state PSD program that remains under approval at 40 CFR § 52.2303).

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

____________________________________ ___________________

Wren Stenger, Director
Multimedia Planning and Permitting Division

Date

Freeport LNG Development, L.P. (PSD-TX-1302-GHG)
Prevention of Significant Deterioration Permit
For Greenhouse Gas Emissions
Draft Permit Conditions

PROJECT DESCRIPTION

Freeport LNG is proposing to add liquefaction infrastructure to its existing Quintana Island Terminal to provide export capacity of a nominal 13.2 million tons per annum (mtpa) of liquefied natural gas (LNG), which equates to processing a nominal 2.2 billion standard cubic feet per day (BSCFD) of pipeline quality natural gas. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Development's existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide (CO_2), sulfur compounds, water, mercury, and heavy hydrocarbons. The pretreated natural gas will then be delivered to the Liquefaction Plant through Freeport LNG's existing 42-inch gas pipeline. At the Liquefaction Plant, the pretreated natural gas will be liquefied and then stored in the LNG storage tanks. LNG will be exported from the terminal by ships arriving via marine transit through the Port Freeport channel.

The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNG's existing 42-inch natural gas pipeline route. The Pretreatment Facility will be comprised of three natural gas pre-treatment systems, five heating medium heaters, three thermal oxidizers, a Natural Gas Liquids removal unit, an emergency ground flare system, a combustion turbine/heat recovery system, five diesel fuel-fired emergency electrical generators, one diesel fuel-fired emergency air compressor engine, one diesel fuel-fired firewater pump system, and additional electrical compression units and connecting laterals for natural gas supply to the Liquefaction Plant.

The Pretreatment Facility includes a heating medium system that is integrated with power production. The heating medium is circulated from the combustion turbine waste heat exchangers to heaters in the amine units, molecular sieve dehydration system, and heavies removal unit. Treated gas from the Pretreatment Facility will be sent via pipeline to the proposed Liquefaction Plant at the Quintana Island Terminal location.

The main components of the Liquefaction Plant will be three liquefaction trains (Train 1, Train 2, and Train 3), each capable of producing a nominal 4.4 million tons per annum (mtpa) of LNG. All three trains and their supporting facilities will be located to the southwest of the existing liquefaction storage and vaporization facilities. In addition to the three liquefaction trains, peripheral aboveground infrastructure will include an emergency ground flare, six diesel fuel-fired emergency electrical generators, one diesel fuel-fired emergency air compressor engine, an emergency firewater unit including two diesel fuel-fired firewater pump engines, an electrical substation, refrigerant and utility storage units, pipe racks and pipes, sumps and associated LNG troughs, a control room, and a maintenance building.

EQUIPMENT LIST

The following equipment is subject to this GHG PSD permit.

Pretreatment Facility Equipment

FIN	EPN	Description
CT	CT	Natural Gas-Fired General Electric 7EA Combustion Turbine (Combustion Unit). The unit has a nominal base-load gross electric power output of approximately 87 MW vented to a heat exchanger for waste heat recovery. The combustion turbine is equipped with selective catalytic reduction (SCR) exhausting through a single flue gas stack.
65B-81A 65B-81B 65B-81C 65B-81D 65B-81E	65B-81A 65B-81B 65B-81C 65B-81D 65B-81E	5 Heating Medium Heaters (Combustion Unit). Each unit has a maximum design heat input rate of 130 MMBtu/hr (HHV), and is fired with natural gas, boil off gas (BOG), or a natural gas/BOG blend. Emissions are combined into an emissions cap (HTRCAP).
AU1/TO1 AU2/TO2 AU3/TO3	TO1 TO2 TO3	3 Regenerative Thermal Oxidizers (Combustion Units).
PTFFLARE	PTFFLARE	1 Emergency Ground Flare (Combustion Units).
PTFFWP	PTFFWP	1 Fire Water Pump (Combustion Units). 660 horsepower (hp) Diesel Fuel-Fired Fire Water Pump limited to 100 hours of operation per year for non-emergency activities.
PTFEG-1 PTFEG-2 PTFEG-3 PTFEG-4 PTFEG-5	PTFEG-1 PTFEG-2 PTFEG-3 PTFEG-4 PTFEG-5	5 Emergency Generators (Combustion Units). 755 horsepower (hp) Diesel Fuel-Fired Emergency Generators limited to 50 hours of operation per year for non-emergency activities for each unit.
PTFEAC-1	PTFEAC-1	1 Emergency Air Compressor Engine (Combustion Unit). 300 horsepower (hp) Diesel Fuel-Fired engine limited to 50 hours of operation per year for non-emergency activities.
FUG-PTSF6	FUG-PTSF6	SF_6 Insulated Electrical Equipment (i.e., circuit breakers) with 978 pounds SF_6 capacity.
FUG-TREAT	FUG-TREAT	Process Fugitives.

Liquefaction Plant Equipment

FIN	EPN	Description
LIQFLARE	LIQFLARE	1 Emergency Ground Flare (Combustion Unit).
LIQFWP-1 LIQFWP-2	LIQFWP-1 LIQFWP-2	2 Fire Water Pumps (Combustion Units). 660 horsepower (hp) Diesel Fuel-Fired Fire Water Pumps limited to 100 hours of operation per year for non-emergency activities for each unit.
LIQEG-1 LIQEG-2 LIQEG-3 LIQEG-4 LIQEG-5	LIQEG-1 LIQEG-2 LIQEG-3 LIQEG-4 LIQEG-5	5 Emergency Generators (Combustion Units). 755 horsepower (hp) Diesel Fuel-Fired Emergency Generators limited to 50 hours of operation per year for non-emergency activities for each unit.
LIQEG-6	LIQEG-6	1 Emergency Generator (Combustion Unit). 400 horsepower (hp) Diesel Fuel-Fired Emergency Generator limited to 50 hours of operation per year for non-emergency activities.

FIN	EPN	Description
LIQEAC-1	LIQEAC-1	1 Emergency Air Compressor Engine (Combustion Unit). 300 horsepower (hp) Diesel Fuel-Fired Engine limited to 50 hours of operation per year for non-emergency activities for each unit.
FUG-LIQSF6	FUG-LIQSF6	SF_6 Insulated Electrical Equipment (i.e., circuit breakers) with 5,683 pounds SF_6 capacity.
FUG-LIQ	FUG-LIQ	Process Fugitives.

I. GENERAL PERMIT CONDITIONS

1) 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.

2) 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 Special Condition V.C.

3) 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.

4) **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 Special Condition I.4.1., 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.

5) **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).

6) **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.

7) **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.

8) 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 PSD Permits PSD-TX-1302 and PSD-TX-1282 and NNSR Permits N150 and N170 (when issued) and all other applicable federal, state, and local air quality regulations. This PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

9) ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
BACT	Best Available Control Technology
BOG	Boil-off Gas
BSCFD	Billion Standard Cubic Feet per Day
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
CT	Combustion Turbine
DLNB	Dry Low-NO_x Burner
dscf	Dry Standard Cubic Foot
EF	Emission Factor
EPN	Emission Point Number
FIN	Facility Identification Number
Fc	Carbon Dioxide-Based Fuel Factor
FR	Federal Register
GCV	Gross Calorific Value
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
LNG	Liquid Natural Gas
MMBtu	Million British Thermal Units
MSS	Maintenance, Start-up and Shutdown
mtpa	Million Tons per Annum
NNSR	Nonattainment New Source Review
N_2O	Nitrous Oxides
NO_x	Nitrogen 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
SF_6	Sulfur Hexafluoride
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TPY	Tons per Year
USC	United States Code
VOC	Volatile Organic Compound

II. Annual Emission Limits

Annual emissions, in tons per year (TPY) on a 12-month, rolling total, 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]		
CT	CT	Combustion Turbine/Waste Heat Recovery (Pretreatment Facility)	CO_2	561,118	561,669	738 lbs CO_2/MWh (based on gross CT energy output and equivalent energy produced) on a 365-day rolling average. See Special Condition III.C.1.
			CH_4	10.6		
			N_2O	1.06		
65B-81A 65B-81B 65B-81C 65B-81D 65B-81E	65B-81A 65B-81B 65B-81C 65B-81D 65B-81E	Heating Medium Heaters[4] (Pretreatment Facility)	CO_2	79,968	80,046	117 lb CO_2e/MMBtu (HHV) for each heater. Minimum Thermal Efficiency of 80% (LHV basis). See Special Condition III.E.1. and 2.
			CH_4	1.5		
			N_2O	0.15		
AU1/TO1	TO1	Amine Unit / Regenerative Thermal Oxidizer 1 (Pretreatment Facility)	CO_2	301,338	301,339	Good Combustion and Operating Practices. See Special Condition III.F.
			CH_4	0.05		
			N_2O	No Emission Limit Established[5]		
AU2/TO2	TO2	Amine Unit / Regenerative Thermal Oxidizer 2 (Pretreatment Facility)	CO_2	301,338	301,339	Good Combustion and Operating Practices. See Special Condition III.F.
			CH_4	0.05		
			N_2O	No Emission Limit Established[5]		
AU3/TO3	TO3	Amine Unit / Regenerative Thermal Oxidizer 3 (Pretreatment Facility)	CO_2	301,338	301,339	Good Combustion and Operating Practices. See Special Condition III.F.
			CH_4	0.05		
			N_2O	No Emission Limit Established[5]		
PTFFLARE	PTFFLARE	Ground Flare (Pretreatment Facility)	CO_2	2,208	2,212	Vent gas releases to flare limited to no more than 3 MMscf/yr on a 12-month rolling total. See Special Condition III.G.3.
			CH_4	0.06		
			N_2O	0.01		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
PTFFWP	PTFFWP	Fire Water Pump (Pretreatment Facility)	CO_2	38	38	Limit operation to no more than 100 hours on a 12-month rolling total. See Special Condition III.H.2.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
PTFEG-1	PTFEG-1	Emergency Generator 1 (Pretreatment Facility)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
PTFEG-2	PTFEG-2	Emergency Generator 2 (Pretreatment Facility)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
PTFEG-3	PTFEG-3	Emergency Generator 3 (Pretreatment Facility)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
PTFEG-4	PTFEG-4	Emergency Generator 4 (Pretreatment Facility)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
PTFEG-5	PTFEG-5	Emergency Generator 5 (Pretreatment Facility)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
PTFEAC-1	PTFEAC-1	Emergency Air Compressor Engine (Pretreatment Facility)	CO_2	9	9	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
LIQFWP-1	LFWP-1	Fire Water Pump (Liquefaction Plant)	CO_2	38	38	Limit operation to no more than 100 hours on a 12-month rolling total. See Special Condition III.H.2.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
LIQFWP-2	LFWP-2	Fire Water Pump (Liquefaction Plant)	CO_2	38	38	Limit operation to no more than 100 hours on a 12-month rolling total. See Special Condition III.H.2.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
LIQEG-1	LIQEG-1	Emergency Generator 1 (Liquefaction Plant)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
LIQEG-2	LIQEG-2	Emergency Generator 2 (Liquefaction Plant)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
LIQEG-3	LIQEG-3	Emergency Generator 3 (Liquefaction Plant)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
LIQEG-4	LIQEG-4	Emergency Generator 4 - Liquefaction (Liquefaction Plant)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
LIQEG-5	LIQEG-5	Emergency Generator 5 (Liquefaction Plant)	CO_2	22	22	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
LIQEG-6	LIQEG-6	Emergency Generator 6 - Liquefaction (Liquefaction Plant)	CO_2	11	11	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
LIQEAC-1	LIQEAC-1	Emergency Air Compressor Engine (Liquefaction Facility)	CO_2	9	9	Limit operation to no more than 50 hours on a 12-month rolling total. See Special Condition III.H.3.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
LIQFLARE	LIQFLARE	Emergency Ground Flare (Liquefaction Plant)	CO_2	11,512	11,523	Vent gas releases to flare limited to no more than 167 MMscf/yr on a 12-month rolling total. See Special Condition III.G.4.
			CH_4	0.22		
			N_2O	0.02		
FUG-PTFSF6 FUG-LIQSF6	FUG-PTFSF6 FUG-LIQSF6	Circuit Breakers (Liquefaction Plant)	SF_6	No Emission Limit Established[6]	No Emission Limit Established[6]	Implementation of LDAR program using infrared camera. See Special Condition III.I.5.
FUG-TREAT and FUG-LIQ	FUG-TREAT and FUG-LIQ	Fugitive Process Emissions (Pretreatment and Liquefaction)	CH_4	No Emission Limit Established[7]	No Emission Limit Established[7]	Implementation of LDAR and AVO monitoring program. See Special Condition III.I.1. and 2.
Totals[8]			**CO_2**	**1,559,209**	**CO_2e 1,561,445**	
			CH_4	**74.5**		
			N_2O	**1.2**		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month, rolling total.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 21, N_2O = 310, SF6=23,900
4. The 5 heaters have an emissions cap.
5. Values are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
6. SF_6 fugitive emissions from EPN FUG-PTFSF6 are estimated to be 0.002 TPY of SF_6 and 47.8 TPY of CO_2e. SF_6 fugitive emissions from EPN FUG-LIQSF6 are estimated to be 0.01 TPY of SF_6 and 239 TPY of CO_2e. The emission limit for EPNs FUG-PTSF6 and FUG-LIQSF6 will be a design/work practice standard as specified in the permit.
7. Fugitive process emissions from EPNs FUG-TREAT and FUG-LIQ are estimated to be 62 TPY of CH_4, and 1,306 TPY CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
8. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. Total emissions are for information only and do not constitute an emission limit.

III. SPECIAL PERMIT CONDITIONS

A. Sitewide Energy Efficiency Requirements

Permittee shall utilize only electric motor primary drivers for the Liquefaction Project. The Permittee shall construct each liquefaction train to have an accompanying natural gas pretreatment unit. Each pretreatment unit shall have the capacity, but is not limited to the capacity, to treat natural gas for one liquefaction train.

B. Combustion Turbine (EPN: CT) Work Practice Standards, Operational Requirements, and Monitoring at Pretreatment Facility:

1. Permittee shall limit fuel to the combustion turbine (CT) to pipeline quality natural gas, boil-off gas (BOG), or BOG supplemented with pipeline quality natural gas with a fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf). The gross calorific value of the fuel shall be determined monthly by the procedures contained in 40 CFR Part 98 and records shall be maintained of the monthly fuel gross calorific value for a period of five years.
2. Natural gas quality fuels with the carbon content will be obtained by semiannual testing per 40 CFR§98.34(b)(3)(A). Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in the combustion turbine (CT) at the time of the request, or shall allow a sample to be taken by EPA for analysis.
3. Permittee shall monitor fuel gas flow continuously; determine fuel higher heating value whenever there is a fuel change or monthly, whichever is less; and calculate the total daily heat input.
4. The flow rate of the fuel combusted in the combustion turbine, identified as CT, shall be measured and recorded using an operational non-resettable elapsed flow meter.
5. Natural gas/boil-off gas flow meter shall be calibrated in accordance with 40 CFR§98.34(b)(1).
6. Flow meters shall meet the specification in 40 CFR 60 Appendix B Spec. 6.
7. All flow meters shall meet the Quality Assurance Specifications in 40 CFR Appendix F.
8. In accordance with 40 CFR Part 60, the Permittee shall ensure that all required fuel flow meters are installed, a periodic schedule for GCV fuel sampling is initiated and all certification tests are completed on or before the earlier of 90 unit operating days or 180 calendar days after the date the affected combustion unit commences commercial operation.
9. Permittee shall measure and record the energy output (MWh [based on adjusted gross CT energy output and equivalent energy produced]) on an hourly basis.
10. The emission limits established in Table 1 include emissions associated with MSS activities.

11. Permittee shall monitor and record the following parameters daily:
    a. Inlet air flow, temperature, pressure, and humidity;
    b. CT fuel input – volumetric measurement of fuel flow converted into mass (lb/hr) and energy flow (MMBtu/hr);
    c. Combustion temperature;
    d. Exhaust temperature;
    e. Gross hourly energy output (Mwh);
    f. CT plant thermal efficiency %;
    g. Gas turbine electrical output, MW;
    h. Chilled water supply and return temperatures; and
    i. Energy input to the chillers.
12. Permittee shall determine the hourly CO_2 emission rate in accordance with 40 CFR Part 98 Subpart C § 98.33(a)(3)(iii).
13. Permittee shall calculate the CH_4 and N_2O emissions on a 12-month rolling basis to be updated by the last day of the following month. 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 HHV (for natural gas and/or boil-off gas), converted to short tons.
14. Permittee shall calculate the CO_2e emissions on a 12-month rolling basis, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on October 30, 2009 (74 FR 56395). The record shall be updated by the last day of the following month.

C. Combustion Turbine (EPN: CT) BACT Emission Limits at Pretreatment Facility:

1. On or after the date of initial startup, Permittee shall not discharge or cause the discharge of emissions from the Combustion Turbine /Waste Heat Recovery Units (CT) into the atmosphere in excess of 738 lbs CO_2/MWh (based on gross CT energy output and equivalent energy produced) on a 365-day rolling average. To determine this BACT emission limit, Permittee shall calculate the limit based on the measured hourly energy output (MWh [based on adjusted gross CT energy output and equivalent energy produced]) and CO_2 emissions as calculated in Special Permit Condition III.B.12. above. The calculated hourly rate is averaged daily.
2. Permittee shall not exceed a Combustion Turbine average heat rate of 5,210 Btu/kWh (LHV, adjusted gross CT energy heat rate with compliance margin) on a 12 month rolling average. To determine this limit, Permittee shall calculate the average heat rate on a hourly basis using the fuel flow rate, fuel HHV,and the measured hourly energy output (kwh [based on adjusted gross CT energy output and equivalent energy produced])). The calculated hourly heat rate is averaged monthly.

3. Within 180 days of the date of initial startup of the combustion turbine, the Permittee shall perform an initial emission test for CO_2 and use emission factors from 40 CFR Part 98. To verify compliance with the BACT emission limit, the Permittee shall calculate the limit based on the measured hourly energy output (MWh [based on adjusted gross CT energy output and equivalent energy produced]) when the CT is operating above 90% of its design capacity, and the results shall be corrected to ISO conditions (59^{o}F, 14.7 psia, and 67% humidity). If the CT does not meet the BACT emissions limit, the Permittee may continue operation of the CT in order to perform necessary corrective actions and to continue plant operations. Once corrective actions have been made, the Permittee will schedule a follow-on emissions test and will make appropriate notifications to the EPA.
4. On or after initial performance testing, Permittee shall use the combustion turbines, and waste heat recovery units energy efficiency processes, work practices and designs as represented in the permit application.

D. Heating Medium Heaters (EPNs: 65B-81A, 65B-81B, 65B-81C, 65B-81D, and 65B-81E) Work Practice Standards, Operational Requirements, and Monitoring at the Pretreatment Facility:

1. Heaters shall combust only pipeline quality natural gas, BOG, or a natural gas/BOG mixture.
2. Permittee shall measure and record the fuel flow rate using an operational non-resettable elapsed flow meter.
3. Permittee shall calibrate and perform a preventative a maintenance check of the fuel gas flow meters and document annually.
4. Permittee shall perform a preventative maintenance check of oxygen control analyzers and document annually.
5. Permittee shall perform maintenance of the burners, at a minimum of, annually.
6. The maximum firing rate for the heaters shall not exceed 130 MMBtu/hr (HHV) per unit.
7. The one-hour maximum firing rates shall be calculated daily to demonstrate compliance with the firing rates in Special Condition III.D.6.
8. Permittee shall install, operate, and maintain an automated air/fuel control system.
9. Permittee shall calibrate and perform preventative maintenance on the air/fuel control analyzers, at a minimum, annually.
10. The heaters must comply with the CO_2e emissions cap in Table 1.
11. Permittee shall calculate the amount of CO_2 (mass basis) emitted for the heaters in tons per year (tpy) on a 12-month rolling total based on metered fuel consumption and using the Tier III methodology in accordance with 40 CFR Part 98 Subpart C § 98.33(a)(3)(iii).
12. Permittee shall calculate the CH_4 and N_2O emissions on a 12-month rolling basis to be updated by the last day of the following month. 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 HHV (for natural gas and/or boil-off gas), converted to short tons.

13. Permittee shall calculate the CO_2e emissions on a 12-month rolling basis, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on October 30, 2009 (74 FR 56395). The record shall be updated by the last day of the following month.

E. Heating Medium Heaters (EPNs: 65B-81A, 65B-81B, 65B-81C, 65B-81D, and 65B-81E) BACT Emission Limits at Pretreatment Facility:

1. The heaters shall meet a BACT limit of 117 lb CO_2e/MMBtu for each heater on a 12-month rolling average basis.
2. The Permittee shall maintain a minimum overall thermal efficiency of 80% (LHV) or greater on a 12-month rolling average basis, calculated monthly, for the heaters (65B-81A, 65B-81B, 65B-81C, 65B-81D, and 65B-81E).
3. The heaters (65B-81A, 65B-81B, 65B-81C, 65B-81D, and 65B-81E) will be continuously monitored for exhaust temperature, input fuel temperature, and stack oxygen. Thermal efficiency for heaters will be calculated monthly from these parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4^{th} ed.) Annex G.

F. Regenerative Thermal Oxidizers (EPNs: TO1, TO2, and TO3) Work Practice Standards, Operational Requirements, and Monitoring at the Pretreatment Facility

1. Each of the three natural gas pre-treatment train amine units (AU1, AU2, and AU3) shall be equipped with a regenerative thermal oxidizer (TO1, TO2, and TO3). Each regenerative thermal oxidizer shall combust low-VOC concentration waste gas from the amine units. The maximum heat input rate to each regenerative thermal oxidizer combustion burner shall not exceed 5 MMBtu/hr when firing natural gas, BOG, or a natural gas/BOG blend.
2. Each regenerative thermal oxidizer shall have an initial stack test, to verify destruction and removal efficiency (DRE) for VOC of 99% or an outlet concentration of 10 ppmv VOC, as propane, corrected to 3% O2 whichever limit is more stringent.
3. For combustion burner fuel flow shall be recorded using an operational non-resettable elapsed flow meter at each thermal oxidizer.
4. The flow rate of the fuel gas (natural gas, BOG or natural gas/BOG blend to the regenerative thermal oxidizer burner) and waste gas flow rate to each thermal oxidizer shall be measured and recorded separately using an operational non-resettable elapsed flow meter at each regenerative thermal oxidizer. Waste gas will be sampled and analyzed on a quarterly basis for composition. The sampled data will be

used to calculate GHG emissions to show compliance with the limits specified in Table 1.

5. Permitee shall calculate CO_2 emissions to show compliance with the limits specified in Table 1, on a monthly basis, using the measured waste gas flow rate and equation W-3 in 40 CFR Part 98, Subpart W [98.233(d)(2)] for the vent gas stream from the amine units.
6. Periodic maintenance shall be performed to maintain the efficiency of the regenerative thermal oxidizer at a minimum annually or as recommended by manufacturer specifications.
7. The Permittee shall maintain the combustion temperature at a minimum of 1,525 ºF (on a rolling 3-hour block average basis) at all times when processing waste gas from the amine units in the regenerative thermal oxidizer. Temperature monitoring of the regenerative thermal oxidizer will ensure proper operation. The Permittee shall install a temperature sensor with a measurement sensitivity of 5 degrees Fahrenheit or 1.0 percent of the temperature value, whichever is larger, expressed in degrees Farenheight.

G. Flares (EPN: PTFFLARE (Pretreatment Facility) and EPN: LIQFLARE (Liquefaction Plant)) Work Practice Standards, Operational Requirements, and Monitoring

1. Flares 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 § 98.233(n).
2. Flares (PTFFLARE and LIQFLARE) are intermittent use flares, not continuous process flares. Emission Units, PTFFLARE and LIQFLARE, shall only combust pilot gas as a continuous stream.
3. Both flares are pressure-assisted. BACT for the Pretreatment Flare (PTFFLARE) will be to limit maintenance startup and shutdown vent gas releases to the flare to no more than 3 MMscf/yr based on a rolling 12-month rolling total.
4. BACT for the Liquefaction Flare (LIQFLARE) will be to limit maintenance startup and shutdown vent gas releases to the flare to no more than 167 MMscf/yr based on a rolling 12-month rolling total.
5. Permittee must record the time, date, volume of gas sent to flare in cubic feet and duration of each MSS event. The records must include hourly CH_4 emission levels as measured by the in-line gas analyzer (Gas chromatograph or equivalent with volumetric gas flow rate) and the calculations based on the actual volumetric flow for the CO_2, N_2O, and CH_4 emissions during each MSS event. These records must be kept for five years following the date of each event.
6. Permittee must record the fuel heat input rate (HHV) in MMBtu/hr to the flare pilots 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 volumetric stack gas flow rate) 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.

7. Each 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.

H. Fire Water Pumps (EPN: PTFFWP (Pretreatment Facility) and EPN: LIQFWP-1 and LIQFWP-2 (Liquefaction Plant)) and Emergency Generators (EPNs: PTFEG-1, PTFEG-2, PTFEG-3, PTFEG-4, and PTFEG-5 (Pretreatment Facility) and EPNs: LIQEG-1, LIQEG-2, LIQEG-3, LIQEG-4 , LIQEG-5, and LIQEG-6 (Liquefaction Plant)) Emergency Air Compressors (EPN: PTFEAC-1 (Pretreatment Facility) and EPN: LIQEAC-1 (Liquefaction Plant))Work Practice Standards, Operational Requirements, and Monitoring

1. The Diesel Fired Fire Water Pumps (PTFFWP, LIQFWP-1, and LIQFWP-2), Diesel Fired Emergency Generators (PTFEG-1, PTFEG-2, PTFEG-3, PTFEG-4, PTFEG-5 LIQEG-1, LIQEG-2, LIQEG-3, LIQEG-4, LIQEG-5, and LIQEG-6), and Emergency Air Compressors (PTFEAC-1 and LIQEAC-1) are authorized to fire diesel fuel containing no more than 0.0015 percent sulfur by weight. Upon request, Permittee shall provide a sample and/or an analysis of the fuel-fired in the emission units (PTFFWP, LIQFWP-1, LIQFWP-2, PTFEG-1, PTFEG-2, PTFEG-3, PTFEG-4, PTFEG-5, LIQEG-1, LIQEG-2, LIQEG-3, LIQEG-4, LIQEG-5, LIQEG-6, PTFEAC-1, and LIQEAC-1) or shall allow a sample to be taken by EPA for analysis to demonstrate the percent sulfur of the fuel.
2. The Diesel Fired Fire Water Pumps (PTFFWP, LIQFWP-1, and LIQFWP-2) are limited to 100 hours of non-emergency operation per year, based on a rolling 12-month total, for each unit.
3. The Diesel Fired Emergency Generators (PTFEG-1, PTFEG-2, PTFEG-3, PTFEG-4, PTFEG-5 LIQEG-1, LIQEG-2, LIQEG-3, LIQEG-4, LIQEG-5, and LIQEG-6) and Emergency Air Compressors (PTFEAC-1 and LIQEAC-1) are limited to 50 hours of non-emergency operation per year, based on a rolling 12-month total, for each unit.
4. The Fire Water Pumps shall have a rating of no more than 660 hp.
5. Emergency Generators (PTFEG-1, PTFEG-2, PTFEG-3, PTFEG-4, PTFEG-5 LIQEG-1, LIQEG-2, LIQEG-3, LIQEG-4, and LIQEG-5) will have a rating of no more than 755 hp.
6. Emergency Generator LIQEG-6 will have a rating of no greater than a 400 hp .
7. Emergency Air Compressors (PTFEAC-1 and LIQEAC-1) will have a rating of no greater than 300 hp.
8. The Diesel Fired Fire Water Pumps, Diesel Fired Emergency Generators, and Emergency Air Compressors shall meet the monitoring and recordkeeping

requirements as required in 40 CFR Part 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

9. Permittee shall install and maintain an operational non-resettable elapsed run time meter for the Diesel Fired Fire Water Pumps, Diesel Fired Emergency Generators, and Emergency Air Compressors.
10. Permittee shall maintain a file of all records, data measurements, reports and documents related to the operation of the Diesel Fired Fire Water Pumps, Diesel Fired Emergency Generators, and Emergency Air Compressors including, but not limited to, the following:
    a) all records or reports pertaining to maintenance performed;
    b) for each diesel fuel oil delivery, documents from the fuel supplier certifying compliance with the fuel sulfur content limit of Special Condition III.H.1.;
    c) hours of operation; and
    d) any other information required by this permit recorded in a permanent form suitable for inspection.
11. The file must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.
12. Compliance with the Annual Emission Limit shall be demonstrated on a 12-month total, rolling monthly, calculated in accordance with 40 CFR Part 98, Subpart C, § 98.33(a)(1)(i).

I. Fugitive Emission Sources (EPNs: FUG-TREAT, FUG-LIQ, FUG-PTFSF6, and FUG-LIQSF6) at the Pretreatment Facility and Liquefaction Plant Work Practice Standards, Operational Requirements, and Monitoring

1. The Permittee shall implement the TCEQ 28MID leak detection and repair (LDAR) program for fugitive emissions of methane.
2. The Permittee shall implement an audio/visual/olfactory (AVO) monitoring program to monitor for leaks in between instrument monitoring required by III.I.1.
3. AVO monitoring shall be performed on a weekly basis.
4. For emission unit FUG-PTSF6 and FUG-LIQSF6, SF_6 emissions shall be calculated annually (calendar year) in accordance with the mass balance approach provided in equation DD-1 of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use, 40 CFR Part 98, Subpart DD.
5. The Permittee shall monitor for leaks of SF6 on a monthly basis using an infrared camera.
6. Permittee shall not exceed 19 new 163 lb (6 at the Pretreatment Facility and 13 at the Liquefaction Plant) and 27 new 132 lb (Liquefaction Plant) enclosed-pressure SF_6 circuit breakers with leak detection.
7. The Permittee shall maintain a file of all records, data measurements, reports and documents related to the fugitive emission sources including , but not limited to, the following: all records or reports pertaining to maintenance performed, all records

relating to compliance with the Monitoring and Quality Assurance and Quality Control (QA/QC) procedures outlined in 40 CFR 98.304.

J. Continuous Emissions Monitoring Systems (CEMS)

1. As an alternative to Special Conditions III.B.12., III.D.11., and III.F.5. Permittee may install a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions discharged to the atmosphere, and use these values to show compliance with the annual emission limit in Table 1.
2. Permittee shall ensure that all required CO_2 monitoring system/equipment are installed and all certification tests are completed on or before the earlier of 90 unit operating days or 180 calendar days after the date the unit commences operation.
3. Permittee shall ensure compliance with the specifications and test procedures for CO_2 emission monitoring system at stationary sources, 40 CFR Part 98, or 40 CFR Part 60, Appendix B, Performance Specification numbers 1 through 9, as applicable.

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 affected emergency generator engines, emergency compressor engines, and firewater pump engines;
   b. The natural gas fuel and boil off gas usage rate (scf) for all combustion sources, using non-resettable elapsed fuel flow monitors; and
   c. Monthly fuel sampling for fuel gas (BOG), quarterly fuel sampling of waste gas.

2. Permittee 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.
3. Permittee shall maintain all records, data, measurements, reports, and documents related to the operation of the affected combustion units, including, but not limited to, the following: all records or reports pertaining to significant maintenance performed on any affected combustion unit; duration of maintenance, startup, shutdown events and the initial startup period for the affected combustion units; malfunctions that may result in excess GHG emissions; all records relating to performance tests, calibrations, checks, and monitoring of affected combustion equipment; duration of an inoperative monitoring devices and affected combustion 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 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 testing as required by Special Condition V 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 Permittee 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 Combustion Turbine/Waste Heat Recovery Units (CT), Heating Medium Heaters (65B-81A, 65B-81B, 65B-81C, 65B-81D, and 65B-81E), and Thermal Oxidizers (TO1, TO2, and TO3) 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. The Permittee shall multiply the CO_2 hourly average emission rate determined under maximum operating test conditions by 8,760 hours except for the five Heating Medium Heaters (65B-81A, 65B-81B, 65B-81C, 65B-81D, and 65B-81E). For the five Heating Medium Heaters (65B-81A, 65B-81B, 65B-81C, 65B-81D, and 65B-81E), a composite average CO_2 emission rate of all five heaters (based on the CO_2

hourly average emission rate determined for each heater) shall be multiplied by 26,952 hours of operation per year for all 5 heaters combined for comparison to the heaters' CO_2 emission limit (TPY) in Table 1.

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 potential to exceed 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 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. Fuel sampling for emission units CT, 65B-81A, 65B-81B, 65B-81C, 65B-81D, and 65B-81E, shall be conducted in accordance with 40 CFR Part 75 and Part 98.

E. The combustion turbine shall be tested at or above 90% of maximum load operation. The permit holder shall present at the pretest meeting the manner in which stack sampling will be executed in order to demonstrate compliance with the emissions limits contained in Section II.

F. 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.

G. 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.

H. 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.

I. 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.

J. Emissions testing, as outlined above, shall be performed 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

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

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

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

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