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-1354-GHG
PERMITTEE:	M & G Resins USA, L.L.C. 450 Gears Rd Ste 240 Houston, Texas 77067-4513
FACILITY NAME:	Utility Plant
FACILITY LOCATION:	7001 Joe Fulton International Trade Corridor, Suite 200, Corpus Christi, Texas 78409

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 M & G Resins USA, L.L.C. (M&G Resins) for Greenhouse Gas (GHG) emissions. The Permit for the Utility Plant applies to the construction of a plant, as part of a larger new major stationary source located in Nueces County, Texas, that consists of (1) a combined heat and power plant option or (2) three boilers with no power production option.

M&G Resins is authorized to construct a new utility plant as described herein, in accordance with the permit application (and plans submitted with the permit application), the federal PSD regulations at 40 CFR § 52.21, and other terms and conditions set forth in this PSD permit in conjunction with the corresponding Texas Commission on Environmental Quality (TCEQ) PSD permit No. PSD-TX-1354. 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 M&G Resins 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 immediately upon issuance of this final decision.

Wren Stenger

Wren Stenger, Director
Multimedia Planning and Permitting Division

11/18/14
Date

M&G Resins USA, L.L.C. (PSD-TX-1354-GHG)
Prevention of Significant Deterioration Permit
For Greenhouse Gas Emissions
Permit Conditions

PROJECT DESCRIPTION

M&G Resins USA, L.L.C. (M&G Resins) is proposing the construction of a new Utility Plant that will either be composed of a Combined Heat and Power (CHP) Plant (Option 1) or three auxiliary boilers with no power production (Option 2). The equipment will support the new collocated PET Plant, an M&G Resins manufacturing facility comprised of a new polyethylene terephthalate (PET) unit and a new terephthalic acid (PTA) unit located in Corpus Christi, Nueces County, Texas. The Utility Plant will provide steam to the M&G Resins plant. Power will also be supplied by the CHP plant, if constructed.

The new CHP plant (Option 1) will generate approximately 49 megawatts (MW) of gross electrical power in addition to high and low pressure steam for use in the PET plant. Power generating equipment, as well as ancillary equipment, is listed below:

- One General Electric LM6000 natural gas-fired combustion turbine equipped with lean pre-mix low-NO_x combustors
- One heat recovery steam generator (HRSG) with 263 million British thermal units per hour (MMBtu/hr) natural gas-fired duct burner system containing a selective catalytic reduction system (SCR)
- One 445 MMBtu/hr natural gas-fired boiler (Auxiliary Boiler A1)
- One 250 MMBtu/hr natural gas-fired boiler (Auxiliary Boiler B)
- Natural gas venting
- Natural gas piping and metering

The three Auxiliary Boilers (Option 2) will produce high and low pressure steam for use in the PET plant. Boilers, as well as ancillary equipment, are listed below:

- One 445 MMBtu/hr natural gas-fired boiler (Auxiliary Boiler A1)
- One 445 MMBtu/hr natural gas-fired boiler (Auxiliary Boiler A2)
- One 250 MMBtu/hr natural gas-fired boiler (Auxiliary Boiler B)
- Natural gas venting
- Natural gas piping and metering

EQUIPMENT LIST

The following equipment is subject to this GHG PSD permit.

Option 1 (CHP Facility) Equipment

FIN	EPN	Description
CTG	CTG	Natural Gas-Fired General Electric LM6000 Combustion Turbine. The unit has a nominal base-load gross electric power output of approximately 49 MW vented to a 263 MMBtu/hr duct-fired HRSG for steam generation (Combustion Unit). The Combustion Unit is
AUXBLRA1	AUXBLRA1	Natural Gas-Fired Boiler. The unit has a maximum heat input capacity of 445 MMBtu/hr.
AUXBLRB	AUXBLRB	Limited-use Natural Gas-Fired Boiler. The unit has a maximum heat input capacity of 250 MMBtu/hr.
NG-FUG	NG-FUG	Natural Gas Piping and Metering Equipment Leak Components.
MSS-FUG	MSS-FUG	Natural Gas Venting related to Turbine Startup and Shutdown and Equipment Maintenance.

Option 2 (Three Auxiliary Boilers) Equipment

FIN	EPN	Description
AUXBLRA1	AUXBLRA1	Natural Gas-Fired Boiler. The unit has a maximum heat input capacity of 445 MMBtu/hr.
AUXBLRA2	AUXBLRA2	Natural Gas-Fired Boiler. The unit has a maximum heat input capacity of 445 MMBtu/hr.
AUXBLRB	AUXBLRB	Limited-use Natural Gas-Fired Boiler. The unit has a maximum heat input capacity of 250 MMBtu/hr.
NG-FUG	NG-FUG	Natural Gas Piping and Metering Equipment Leak Components.
MSS-FUG	MSS-FUG	Natural Gas Venting related to Equipment Maintenance.

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 VI, 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 VI.C.

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 Sections II and III of this permit.

2. Within 10 days of the restoration of normal operations after any failure described in condition 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 PSD Permit PSD-TX-1354 (when issued) and all other applicable federal, state, and local air quality regulations. This PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

I. ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
BACT	Best Available Control Technology
CAA	Clean Air Act
CC	Carbon Content
CCS	Carbon Capture and Sequestration
CHP	Combined Heat and Power
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
HRSG	Heat Recovery Steam Generator
HHV	High Heating Value
hr	Hour
lb	Pound
LDAR	Leak Detection and Repair
MMBtu	Million British Thermal Units
MSS	Maintenance, Start-up and Shutdown
N_2O	Nitrous Oxides
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 average shall not exceed the following:

Table 1A. Annual Emission Limits (Option 1)[1]

FIN	EPN	Description	GHG Mass Basis		TPY $CO_2e^{2,3}$	BACT Requirements
				TPY[2]		
CTG	CTG	General Electric LM6000 CT with 263 MMBtu/hr Duct Burner and HRSG	CO_2	363,652	364,027	Minimum Thermal Efficiency of 60% (LHV basis). See Special Condition III.C.1. and 2.
			CH_4	6.86		
			N_2O	0.69		
AUXBLRA1	AUXBLRA1	Auxiliary Boiler A1	CO_2	247,281	247,537	Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2.
			CH_4	4.66		
			N_2O	0.47		
AUXBLRB	AUXBLRB	Auxiliary Boiler B	CO_2	127,992	128,125	Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2.
			CH_4	2.41		
			N_2O	0.24		
NG-FUG	NG-FUG	Natural Gas Fugitives	CH_4	No Emission Limit Established[4]	No Emission Limit Established[4]	Implementation of AVO monitoring program. See Special Condition III.F.1. and 2.
MSS-FUG	MSS-FUG	MSS Natural Gas Venting	CH_4	No Emission Limit Established[4]	No Emission Limit Established[4]	Implementation of AVO monitoring program. See Special Condition III.G.1. and 2.
Totals[5]			**CO_2**	**738,926**	**CO_2e 740,199**	
			CH_4	**34**		
			N_2O	**1**		

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 = 25, N_2O = 298, SF_6=22,800
4. Fugitive process emissions from EPNs NG-FUG and MSS-FUG are estimated to be 20 TPY of CH_4, and 511 CO_{2e}. The emission limit will be a design/work practice standard as specified in the permit.
5. 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.

Table 1B. Annual Emission Limits (Option 2)[1]

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
AUXBLRA1	AUXBLRA1	Auxiliary Boiler A1	CO_2	247,281	247,537	Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2.
			CH_4	4.66		
			N_2O	0.47		
AUXBLRA2	AUXBLRA2	Auxiliary Boiler A2	CO_2	247,281	247,537	Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2.
			CH_4	4.66		
			N_2O	0.47		
AUXBLRB	AUXBLRB	Auxiliary Boiler B	CO_2	127,992	128,125	Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2.
			CH_4	2.41		
			N_2O	0.24		
NG-FUG	NG-FUG	Natural Gas Fugitives	CH_4	No Emission Limit Established[4]	No Emission Limit Established[4]	Implementation of AVO monitoring program. See Special Condition III.F.1. and 2.
MSS-FUG	MSS-FUG	MSS Natural Gas Venting	CH_4	No Emission Limit Established[4]	No Emission Limit Established[4]	Implementation of AVO monitoring program. See Special Condition III.G.1. and 2.
Totals[5]			**CO_2**	**622,555**	**CO_2e**	
			CH_4	**32**		
			N_2O	**1**	**623,708**	

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 = 25, N_2O = 298, SF_6=22,800
4. Fugitive process emissions from EPNs NG-FUG and MSS-FUG are estimated to be 20 TPY of CH_4, and 511 CO_{2e}. The emission limit will be a design/work practice standard as specified in the permit.
5. 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. Construction Limitations

1. Permittee shall only construct and operate the emission units in either Option 1 or Option 2. No combination of the two options is allowed. Within 120 days of making the selection of which Option to implement, but in any case, no later than 180 days prior to startup, the permit holder must submit a permit application to the permitting authority to administratively amend the permit to remove the relevant provisions from the permit related to the option not selected.

B. Combined Heat and Power Plant (Option 1 EPN: CTG) Work Practice Standards, Operational Requirements, and Monitoring:

1. Permittee shall limit fuel to the combustion turbine (CT) and duct burner (DB) to pipeline quality natural gas with a fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf). The 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. The carbon content of the natural gas fuel shall be obtained by semiannual testing per 40 CFR§98.34(b)(3)(ii)(A). Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in the 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 for both the CT and DB; 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 CT and DB shall be measured with a flow meter and automatically recorded using an operational data acquisition and handling system.

5. Natural gas flow meters shall be calibrated in accordance with 40 CFR§98.34(b)(1).

6. 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.

7. The emission limits established in Table 1A include emissions associated with MSS Activities.

10. Permittee shall monitor and record the following parameters daily:
    a. CT fuel input – volumetric measurement of fuel flow converted into mass (lb/hr) and energy flow (MMBtu/hr);
    b. DB fuel input – volumetric measurement of fuel flow converted into mass (lb/hr) and energy flow (MMBtu/hr);
    c. Gross hourly energy output of CT (kwh);
    d. Hourly steam flow rate (lb/hr);
    e. Hourly steam enthalpy (MMBtu/lb);
    f. Hourly feedwater flow rate (lb/hr);
    g. Hourly feedwater enthalpy (MMBtu/lb);
    h. CHP plant thermal efficiency %;

11. CHP plant thermal efficiency shall be calculated using the inputs from Special Condition No. 10 and the following equation:

Thermal efficiency = [(d x e) - (f x g) + c x 0.00341443] / [(a + b) x LHV of fuel] x 100%

Where

f	=	Hourly feedwater flow rate (lb/hr);
g	=	Hourly feedwater enthalpy (MMBtu/lb);
d	=	Hourly steam flow rate (lb/hr);
e	=	Hourly steam enthalpy (MMBtu/lb);
c	=	Gross hourly energy output of CT (kwh);
a	=	CT fuel input – volumetric measurement of fuel flow converted into mass (lb/hr) and energy flow (MMBtu/hr);
b	=	DB fuel input – volumetric measurement of fuel flow converted into mass (lb/hr) and energy flow (MMBtu/hr);
LHV	=	Lower heating value of fuel.

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), 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 November 29, 2013 (78 FR 71948). The record shall be updated by the last day of the following month.

C. Combined Heat and Power Plant (Option 1 EPN: CTG) BACT Emission Limits:

1. On or after the date of initial startup, Permittee shall maintain a minimum thermal efficiency for the CHP plant of 60% on a 12-month rolling average. To determine this BACT emission limit, Permittee shall calculate the limit based on the measured hourly thermal efficiency. The calculated hourly rate is averaged monthly.

2. 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 also determine the emissions rate based on the relevant methods from 40 CFR Part 98 Subpart C § 98.33(a)(3)(iii). To verify compliance with the BACT emission limit, the Permittee shall calculate the limit based on the measured hourly thermal efficiency of the CHP plant. 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.

3. 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. Auxiliary Boilers (Option 1 EPNs: AUXBLRA1 and AUXBLRB or Option 2 EPNs: AUXBLRA1, AUXBLRA2, and AUXBLRB) Work Practice Standards, Operational Requirements, and Monitoring:

1. Boilers shall combust only pipeline quality natural gas.

2. Permittee shall measure and automatically record the fuel flow rate using an operational data acquisition and handling system.

3. Permittee shall calibrate and perform a preventative 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 AUXBLRA1 and AUXBLRA2 shall not exceed 445 MMBtu/hr (HHV).

7. The maximum firing rate for the AUXBLRB shall not exceed 250 MMBtu/hr (HHV).

8. The one-hour maximum firing rates shall be calculated daily to demonstrate compliance with the firing rates in Special Condition III.D.6. and 7. The rolling 12-month basis shall be calculated monthly for Special Condition III.D.7.

9. Permittee shall install, operate, and maintain an automated air/fuel control system.

10. Permittee shall calibrate and perform preventative maintenance on the air/fuel control analyzers, at a minimum, annually.

11. Permittee shall calculate the amount of CO_2 (mass basis) emitted for the boilers 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), 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 November, 29,2013 (78 FR 71948). The record shall be updated by the last day of the following month.

E. Auxiliary Boilers (Option 1 EPNs: AUXBLRA1 and AUXBLRB or Option 2 EPNs: AUXBLRA1, AUXBLRA2, and AUXBLRB) BACT Emission Limits:

1. The Permittee shall maintain a minimum overall thermal efficiency of 77% (LHV) or greater on a 12-month rolling average basis, calculated monthly, for each boiler (AUXBLRA1, AUXBLRA2, and AUXBLRB).

2. Auxiliary boiler thermal efficiency (AUXBLRA1, AUXBLRA2, and AUXBLRB) shall be calculated using the following equation:

   Thermal efficiency = [(a x b) - (c x d)] / [e x LHV of fuel] x 100%

   Where

a	=	Hourly steam flow rate (lb/hr);
b	=	Hourly steam enthalpy (MMBtu/lb);
c	=	Hourly feedwater flow rate (lb/hr);
d	=	Hourly feedwater enthalpy (MMBtu/lb);
e	=	Boiler fuel input – volumetric measurement of fuel flow converted into mass (lb/hr) and energy flow (MMBtu/hr);
LHV	=	Lower heating value of fuel.

F. Natural Gas Piping and Metering Equipment Leak Components (EPN: NG-FUG) Work Practice Standards, Operational Requirements, and Monitoring

1. The Permittee shall implement an audio/visual/olfactory (AVO) monitoring program to monitor for leaks.

2. AVO monitoring shall be performed on a weekly basis.

3. 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, the date and time that assessments were made and documentation of repairs attempted and achieved, including when the component was restored to proper operation.

G. Natural Gas Piping and Metering Equipment Leak Components (EPN: MSS-FUG) Work Practice Standards, Operational Requirements, and Monitoring

1. The Permittee shall implement work practices that minimize venting of any greenhouse gas from any fuel supply system during de-inventory of such system for maintenance, startup, shutdown, or repair purposes. Such practices may include but are not limited to minimizing the run of piping required to be de-inventoried to that which must be de-inventoried to achieve the needed safe conditions necessary to affect repairs or maintenance activities.

Venting to atmosphere is not permitted when such vented emissions could safely be routed to their ordinary control device, if any.

2. Documentation of the steps taken to minimize the volume of gas vented, including the best estimate of speciation of the gas vented and a good engineering practice based estimate of the quantity of GHG gas so vented. Such documentation shall be made for each such venting event.

3. The Permittee shall maintain a file of all records, data measurements, reports and documents related to venting to atmosphere of natural gas and other GHG containing fuel system feed lines, other GHG containing lines authorized by this permit, and components, including, but not limited to, the following: all records or reports pertaining to the reason the venting event was required, any maintenance performed or repairs affected, the duration of the event, an estimate of the quantity of CO_2e vented during the event, and the date and time of restoration to proper operation.

H. Continuous Emissions Monitoring Systems (CEMS)

1. As an alternative to Special Conditions III.B.12 and III.D.11, 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 1A or 1B, the Permittee will monitor the following parameters and summarize the data on a calendar month basis.

   a. The natural gas fuel usage rate (scf) for all combustion sources, using non-resettable elapsed fuel flow monitors; and

   b. Monthly fuel sampling.

2. 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

3. Permittee shall maintain records of all CO_2 emission certification tests and monitoring and compliance information required by this permit.

4. 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 30^{th} 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.

5. Excess emissions shall be defined as any period in which the facility emissions exceed a maximum emission limit set forth in this permit.

6. Excess emissions indicated by GHG emission source testing as required by Special Condition V, Performance Testing, or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.

7. All records required in Special Condition III.G related to maintenance, startup, and shutdown related venting of GHG to atmosphere, including, based on the records kept, a rolling 12-month total estimate of the CO_2e emissions thus vented.

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. PERFORMANCE TESTING

1. 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/Duct Burner Unit (EPN: CTG), and the Auxiliary Boilers (EPNs: AUXBLRA1, AUXBLRA2, and AUXBLRB) to determine the initial compliance with the CO_2 emission limits established in this permit. In addition to complying with the relevant stack test requirements of 40 CFR §60.8, the following methods, found in 40 CFR Part 60 Appendix A unless otherwise noted, shall be used:
   a. Method 1—Sample and Velocity Traverses for Stationary Sources.
   b. Method 2—Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube).
   c. Method 3b or 3C—Determination of Carbon Dioxide, Methane, Nitrogen, and Oxygen From Stationary Sources.
   d. Method 4—Determination of Moisture Content in Stack Gases. Sampling shall be conducted in accordance with 40 CFR § 60.8 and EPA Method 3a or 3b for the concentration of CO_2.

2. The Permittee shall multiply the CO_2 hourly average emission rate determined under maximum operating test conditions by 8,760 hours for comparison to the units' CO_2 emission limit (TPY) in Table 1.

3. 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.

4. 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.

5. 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.

6. 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.

7. Fuel sampling for emission units CTG, AUXBLRA1, AUXBLRA2, and AUXBLRB shall be conducted in accordance with 40 CFR Part 75 and Part 98.

8. 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.

9. 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.

10. 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.

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

    a. Sampling ports adequate for test methods applicable to this facility,

    b. Safe sampling platform(s),

    c. Safe access to sampling platform(s), and

    d. Utilities for sampling and testing equipment.

12. 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.

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 (6PD-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