

US EPA ARCHIVE DOCUMENT

Statement of Basis

Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the M&G Resins USA LLC, PET and PTA Units (PET Plant) Permit Number: PSD-TX-1352-GHG

This document serves as the statement of basis (SOB) for the above-referenced draft permit, as required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

In February 2013, two separate companies, M&G Resins USA LLC (M&G Resins), and NRG Development Company, Inc. (NRG) each notified the EPA and the Texas Commission on Environmental Quality (TCEQ) by way of Prevention of Significant Deterioration (PSD) permit application submittals that they were planning to develop a common greenfield location near Corpus Christi, Nueces County, Texas into a new chemical process plant with a utility support facility that will together constitute a major stationary source for new source review purposes. See 40 CFR 52.21(b)(5), (6). M&G Resins planned to build a new polyethylene terephthalate (PET) resin manufacturing complex (the PET Plant) while NRG intended to build a collocated combined heat and power utility plant (the Utility Plant) to exclusively serve the steam and electrical demands of M&G Resins' PET plant. The entire project bears the label "Project Jumbo." In March of 2014, M&G Resins acquired ownership of the Utility Plant from NRG and revised the Utility Plant permit application to authorize two optional plant configurations: Option 1: the construction of the combined heat and power plant as originally proposed by NRG, or Option 2: the construction of boiler facilities to provide steam but not to provide power. The company would be obligated to select only one of the two mutually exclusive options under which to construct and operate. Notably, in either configuration, the Utility Plant would not be regulated under the proposed action, "Greenhouse Gas Emissions from New Stationary Sources: Generating Units", (79 FR 1430, January 8, 2014), because it would not meet the applicability criteria set forth in that proposal.¹

While these two plants, the PET plant and the Utility Plant, together constitute a single stationary source for PSD purposes, the applicant requests that the applicable requirements for the Best Available Control Technology (BACT) be addressed through separate proposed PSD permits. Consistent with the state-submitted PSD permit applications, TCEQ is similarly proposing separate PSD permits to address all non-GHG pollutants. This SOB addresses the PSD requirements and associated terms and conditions for GHG emissions from emissions units at the proposed PET Plant. GHG emissions from the Utility plant are addressed via the separately proposed PSD permit PSD-TX-1354-GHG and its supporting statement of basis. While the analysis of Carbon Capture and Storage (CCS) considers the major emitting units for the site as whole (as part of a logical grouping of emission units), this SOB otherwise conducts a BACT review only for the emissions attributable

¹ Specifically, the company represents that under Option 1, it will not meet the criteria of the proposed (79 FR 1430) 40 CFR § 60.4305(c)(5), which reads "(5) Was constructed for the purpose of supplying, and supplies, one-third or more of its potential electric output and delivers more than 219,000 MWh net-electrical output to a utility distribution system on a 3 year rolling average basis."

to PET Plant emissions units and operations. The SOB for the proposed Utility plant PSD permit should be consulted for the full BACT review that applies to Utility plant emissions and emissions units.

The TCEQ is currently developing the combined PSD and minor source permit (PSD-TX-1354/108819) for criteria pollutants from the proposed Utility Plant, and PSD-TX-1352/108446 references the authorizations sought for criteria pollutants from the proposed PET Plant.

After reviewing the PET Plant application, EPA Region 6 has prepared the following statement of basis and a draft air permit to apply GHG PSD requirements to the construction of the PET Plant.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit for the PET Plant. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant will comply with the requirements.

EPA Region 6 concludes that M&G's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by M&G, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

M&G Resins USA, LLC. a wholly owned subsidiary of M&G USA Corporation
The PET Plant
450 Gears Rd. Suite 240
Houston, TX 77067

Physical Address: 7001 Joe Fulton Intl Trade Corridor, Suite 100
Corpus Christi, TX 78409

Contact:
Mauro Fenoglio
Global Manufacturing Director, PET Resin Division
M&G Resins USA, LLC
(281) 874-8074

III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the GHGs (75 FR 25178, promulgating 40 CFR § 52.2305).

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Brad Toups
Air Permitting Section (6PD-R)
(214) 665- 7258

IV. Facility Location

The M&G PET and Utility Plants are collocated in Nueces County, Texas. The address for the PET plant will be:

7001 Joe Fulton Intl Trade Corridor, Suite 100, Corpus Christi, Texas 78409

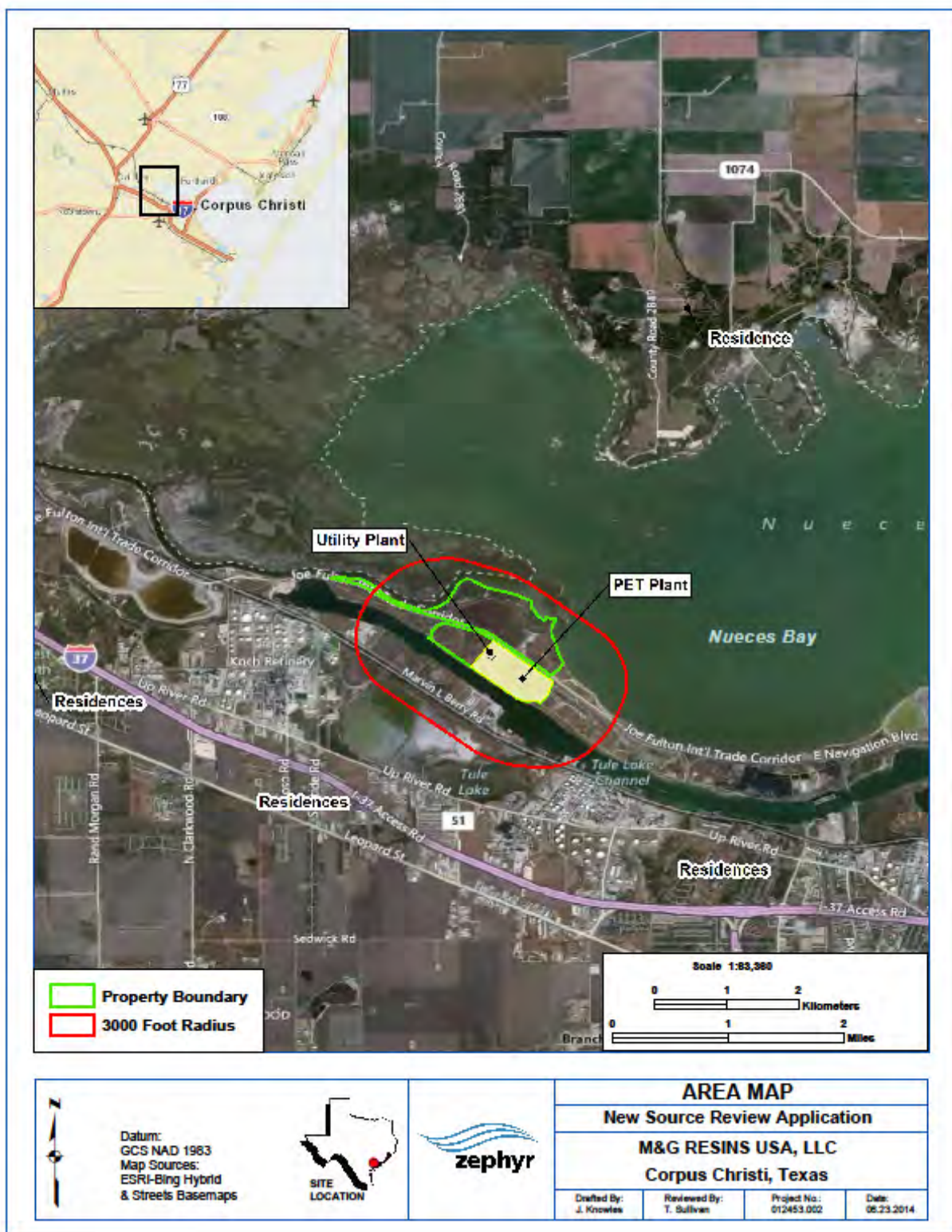
The geographic coordinates for this facility are as follows:

Latitude: 27° 50' 7.8899" North
Longitude: - 97° 29' 38.0256" West

Nueces County is currently designated attainment/unclassifiable for all criteria pollutants. The nearest Class I area, at a distance of more than 870 kilometers, is Breton National Wildlife Refuge.

Figure 1 on the next page illustrates the facility location, and identifies the relative position of the proposed PET Plant and the proposed Utility Plant.

Figure 1. M&G PET Plant and Utility Plant Location



V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA Region 6 implements a GHG PSD FIP for the State of Texas under the provisions of 40 CFR 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305. On June 23, 2014, the United States Supreme Court issued a decision addressing the application of stationary source permitting requirements to greenhouse gases (GHGs). *Utility Air Regulatory Group (UARG) v. Environmental Protection Agency* (EPA) (No. 12-1146). The Supreme Court said that the EPA may not treat greenhouse gases as an air pollutant for purposes of determining whether a source is a major source required to obtain a Prevention of Significant Deterioration (PSD) or title V permit. However, the Court also said that the EPA could continue to require that PSD permits, otherwise required based on emissions of conventional pollutants, contain limitations on GHG emissions based on the application of Best Available Control Technology (BACT). Pending further EPA engagement in the ongoing judicial process before the District of Columbia Circuit Court of Appeals, the EPA is proposing to issue this permit consistent with EPA's understanding of the Court's decision.

The source will constitute a new major source because the facility (a chemical process plant under 40 CFR 52.21(b)(1)(i)(a) with an accompanying support facility) has the potential to emit more than 100 tons per year of CO and VOC. (The applicant has estimated approximately 350 tpy VOC, and greater than 500 tpy CO for the entire project.) In this case, the applicant represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, will determine the project is subject to PSD review for these pollutants as well as any other regulated NSR pollutants determined to equal or exceed the rates set forth in 40 CFR 52.21(b)(23).

The applicant also estimates that this same project emits or has the potential to emit in excess of 1,000,000 tpy CO_{2e} of GHGs, which well exceeds the 75,000 ton per year CO_{2e} threshold in EPA regulations. 40 C.F.R §52.21(b)(49)(iv); see also, PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011) at 12-13. Since the Supreme Court recognized EPA's authority to limit application of BACT to sources that emit GHGs in greater than *de minimis* amounts, EPA believes it may apply the 75,000 tons per year threshold in existing regulations at this time to determine whether BACT applies to GHGs at this facility.

Accordingly, this project continues to require a PSD permit that includes limitations on GHG emissions based on application of BACT. The Supreme Court's decision does not limit the FIP authority and responsibility of Region 6 with regard to this particular permitting action. Accordingly, under the circumstances of this project, the TCEQ will issue the non-GHG portion of the permit and EPA will issue the GHG portion.

EPA Region 6 proposes to follow the policies and practices reflected in EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011). For the reasons described in that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA believes that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the project has regulated NSR pollutants that are non-GHG pollutants, which are addressed by the PSD permit to be issued by TCEQ.

VI. Project/Process Description

The proposed GHG PSD permit, if finalized, will allow M&G to construct the new PET plant, which will consist of a terephthalic acid (PTA) unit that provides feedstock to a polyethylene terephthalate (PET) unit. The new PET plant will be located at M&G's site as previously described.

The PET plant sources account for approximately 37-42% of the sitewide GHG emissions.

The Utility Plant will account for between 58 and 63% of the sitewide emissions, based on the final selection of Option 1 (generate electricity and steam in the Utility Plant) or Option 2 (purchase electricity and generate steam in the Utility Plant). The estimated sitewide emissions are as follows:

GHG ¹	Sitewide Total GHG with Utility Plant Option 1			Sitewide Total GHG with Utility Plant Option 2		
	PET Plant	Utility Plant	Total	PET Plant	Utility Plant	Total
CO₂	432,946	738,926	1,171,872	432,946	622,555	1,055,501
CH₄	193	34	227	193	32	225
N₂O	2	1	3	2	1	3
CO₂e	438,367	740,074	1,178,441	438,367	623,653	1,062,020
% of Total →	37.20%	62.80%		41.28%	58.72%	

¹. CO₂e emissions are calculated by multiplying the mass emissions rate of each GHG constituent by the global warming potential value, as published in 40 CFR Part 98. The current values are CO₂=1, CH₄=25, and N₂O=298.

While Option 2 if chosen would have the lower GHG emissions for the site, Option 2 would require power purchased from the grid. Power generation offsite would also create GHG emissions, but those emissions would not be accounted for in this project as it is not possible to identify the particular location where the necessary electrical generation would take place for use by the facility.

While the above table depicts GHG emissions sitewide, Table 1a, below, shows the estimated emissions for the PET plant broken down by emissions unit, while Tables 1b and 1c show the GHG emissions for the two options for the Utility Plant.

Table 1a. M&G PET Plant Annual Emissions and BACT Summary							CO ₂ Mass Emissions		
FIN	EPN	Description	GHG Mass Basis		TPY CO ₂ e	BACT Requirements	of Site		of Plant
			GHG	TPY					
E7-A	E7-A	Heat Transfer Fluid (HTF) Heater-On Nat.Gas	CO ₂	72,622	72,622	Limit the exhaust gas temperature from the HTF Heaters to 320°F. See permit condition III.A.6	300,069		290,488
			CH ₄	1.37	34.25		25.6%	of Opt 1	67.1%
			N ₂ O	0.14	41.72		28.4%	of Opt 2	
E7-B	E7-B	Heat Transfer Fluid (HTF) Heater-On Nat.Gas	CO ₂	72,622	72,622	Limit the exhaust gas temperature from the HTF Heaters to 320°F. See permit condition III.A.6			
			CH ₄	1.37	34.25				
			N ₂ O	0.14	41.72				
E7-C	E7-C	Heat Transfer Fluid (HTF) Heater-On Nat.Gas	CO ₂	72,622	72,622	Limit the exhaust gas temperature from the HTF Heaters to 320°F. See permit condition III.A.6			
			CH ₄	1.37	34.25				
			N ₂ O	0.14	41.72				
E7-D	E7-D	Heat Transfer Fluid (HTF) Heater-On Nat.Gas	CO ₂	72,622	72,622	Limit the exhaust gas temperature from the HTF Heaters to 320°F. See permit condition III.A.6			
			CH ₄	1.37	34.25				
			N ₂ O	0.14	41.72				
E7-A to D ¹	E7-A to D	Heat Transfer Fluid (HTF) Heaters-On Fuel Gas (3)	CO ₂	9,581	9,581	Limit the exhaust gas temperature from the HTF Heaters to 320°F. See permit condition III.A.6			
			CH ₄	0.21	5.13				
			N ₂ O	0.02	6.26				
E1 ³	E1	Regenerative Thermal Oxidizer 1 (RTO1)-On Waste Gas (4)	CO ₂	54,495	54,495	Maintain a minimum combustion temperature as determined by initial compliance testing. See permit condition III.C.	127,196		108,990
			CH ₄	83	2,075		10.9%	of Opt 1	25.2%
			N ₂ O	0.54	160.92		12.1%	of Opt 2	
		Regenerative Thermal Oxidizer 1 (RTO1)-On Nat.Gas	CO ₂	9,103	9,103	Maintain a minimum combustion temperature as determined by initial compliance testing. See permit condition III.C.			
			CH ₄	0.17	4.25				
			N ₂ O	0.02	5.96				
E2 ³	E2	Regenerative Thermal Oxidizer 2 (RTO2)-On WasteGas (4)	CO ₂	54,495	54,495	Maintain a minimum combustion temperature as determined by initial compliance testing. See permit condition III.C.			
			CH ₄	83	2,075				
			N ₂ O	0.54	160.92				
		Regenerative Thermal Oxidizer 2 (RTO2)-On Nat.Gas	CO ₂	9,103	9,103	Maintain a minimum combustion temperature as determined by initial compliance testing. See permit condition III.C.			
			CH ₄	0.17	4.25				
			N ₂ O	0.02	5.96				
FLARE ²	FLARE	Biogas Flare-Flaring Biogas and including nat gas pilot	CO ₂	8,942	8,942	Good combustion and maintenance practices. See permit condition III.B	8,942		8,942
			CH ₄	13.60	340.00		0.8%	of Opt 1	2.1%
			N ₂ O	0.09	26.52		0.8%	of Opt 2	
		Biogas Flare-On Nat.Gas for flare pilot	CO ₂	31	31	Good combustion and maintenance practices. See permit condition III.B			
			CH ₄	5.89E-04	0.01				
			N ₂ O	5.89E-05	0.02				
E85-A	E85-A	Emergency Diesel Generator	CO ₂	2,577	2,577	Low annual capacity factor and annual routine maintenance as prescribed by NSPS. See permit condition III.D.	5,650		5,650
			CH ₄	0.1	2.5		0.5%	of Opt 1	1.3%
			N ₂ O	0.02	5.96		0.5%	of Opt 2	
E85-B	E85-B	Emergency Diesel Generator	CO ₂	2,577	2,577	Low annual capacity factor and annual routine maintenance as prescribed by NSPS. See permit condition III.D.			
			CH ₄	0.1	2.5				
			N ₂ O	0.02	5.96				
E87-A	E87-A	Fire Water Pump Diesel Generator	CO ₂	248	248	Low annual capacity factor and annual routine maintenance as prescribed by NSPS. See permit condition III.E.	689		689
			CH ₄	0.01	0.25		0.1%	of Opt 1	0.2%
			N ₂ O	0.002	0.596		0.1%	of Opt 2	
E87-B	E87-B	Fire Water Pump Diesel Generator	CO ₂	248	248	Low annual capacity factor and annual routine maintenance as prescribed by NSPS. See permit condition III.E.			
			CH ₄	0.01	0.25				
			N ₂ O	0.002	0.596				
FUGPTA	FUGPTA	Combined Plant Fugitives	CO ₂	0.72	0.72	Implementation of LDAR/AVO program. See permit condition III.F.	193		193
FUGPET	FUGPET		CH ₄	20.27	506.75		0.0%	of Opt 1	0.0%
Totals			CO ₂	432,946	CO ₂ e				
			CH ₄	193	438,273				
			N ₂ O	2					

Notes:

- Biogas is normally routed to any of the four heaters simultaneously, or to the flare, but not to both the flare and heaters concurrently. The emissions for the heaters include the maximum contribution of bio gas which offsets heater natural gas use.
- Waste gas may be routed to the flare, but if so, won't be routed to any heater. Monitoring provisions assure compliance. Therefore, the Biogas Flaring is omitted from the total.
- RTOs use natural gas for startup and supplementally as needed to maintain proper operating temperature but the heating value necessary to properly operate the RTO normally is supplied by the waste gas being treated by the RTO, therefore the emissions attributable to waste gas include the natural gas supplementally fired.
- Natural Gas can and will be fired concurrently with waste gas in the RTO to maintain proper operating conditions.

Table 1b M&G Project Jumbo GHG Emissions- Utility Plant									
Utility Plant: Option 1									
FIN	EPN	Description	GHG Mass Basis		TPY CO ₂ e	BACT Requirements	CO ₂ Mass Emissions		
			GHG	TPY ²			of Site		of Plant
CTG	CTG	General Electric LM6000 CT with 245 MMBtu/hr Duct Burner and HRSG	CO ₂	363,652	363,652	Minimum Thermal Efficiency of 60% (LHV basis). See Special Condition III.E.1. and 2.	363,652		363,652
			CH ₄	6.86	171.50		31.0%		49.2%
			N ₂ O	0.69	205.62				
AUXBLRA1	AUXBLRA1	Auxiliary Boiler A1	CO ₂	247,281	247,281	Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2.	247,281		247,281
			CH ₄	4.66	116.50		21.1%		33.5%
			N ₂ O	0.47	140.06				
AUXBLRB	AUXBLRB	Auxiliary Boiler B	CO ₂	127,992	127,992	Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2.	127,992		127,992
			CH ₄	2.41	60.25		10.9%		17.3%
			N ₂ O	0.24	71.52				
NG-FUG	NG-FUG	Natural Gas Fugitives	CO ₂	1	1	Implementation of AVO monitoring program. See Special Condition III.I.1. and 2.			
			CH ₄	20.27	506.75				
			N ₂ O						
MSS-FUG	MSS-FUG	MSS Natural Gas Venting	CO ₂	0	0	Implementation of AVO monitoring program. See Special Condition III.I.1. and 2.			
			CH ₄	0.106	2.65				
			N ₂ O						
Totals			CO ₂	738,926	CO ₂ e	62.8% of sitewide emissions			
			CH ₄	34.3	740,201				
			N ₂ O	1.4					

Table 1c M&G Project Jumbo GHG Emissions- Utility Plant									
Utility Plant: Option 2									
FIN	EPN	Description	GHG Mass Basis		TPY CO ₂ e	BACT Requirements	CO ₂ Mass Emissions		
			GHG	TPY ²			of Site		of Plant
AUXBLRA1	AUXBLRA1	Auxiliary Boiler A1	CO ₂	247,281	247,281	Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2.	494,562		494,562
			CH ₄	4.66	116.50		46.9%		79.4%
			N ₂ O	0.47	140.06				
AUXBLRA2	AUXBLRA2	Auxiliary Boiler A2	CO ₂	247,281	247,281	Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2.			
			CH ₄	4.66	116.50				
			N ₂ O	0.47	140.06				
AUXBLRB	AUXBLRB	Auxiliary Boiler B	CO ₂	127,992	127,992	Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2.	127,992		127,992
			CH ₄	2.41	60.25		12.1%		20.6%
			N ₂ O	0.24	71.52				
NG-FUG	NG-FUG	Natural Gas Fugitives	CO ₂	1	1	Implementation of AVO monitoring program. See Special Condition III.I.1. and 2.			
			CH ₄	20.27	506.75				
			N ₂ O						
MSS-FUG	MSS-FUG	MSS Natural Gas Venting	CO ₂	0	0	Implementation of AVO monitoring program. See Special Condition III.I.1. and 2.			
			CH ₄	0.106	2.65				
			N ₂ O						
Totals			CO ₂	622,555	CO ₂ e	58.7% of sitewide emissions			
			CH ₄	32.1	623,709				
			N ₂ O	1.2					

As discussed previously, this SOB addresses the emissions units that are part of the PET Plant. The Utility Plant authorization basis and requirements are found in the proposed Utility Plant permit. The Utility Plant emissions are provided here to give a complete picture of emissions from Project Jumbo, which is the combination of the PET and Utility plants.

A detailed discussion of the PET plant processes are provided in the Section 3 of the permit application² and are reiterated here so that the sources and emissions points of GHG are better

² M&G Resins PET GHG PSD Permit Application dated Feb 28 2013.pdf available here:
<http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/m-g-resins-projectjumbo-app.pdf>

understood, as much energy reuse is part of the design, and this energy reuse is in the form of waste gases from the various parts of the process from which energy is extracted.

VI.A. PET Plant Processes

The major processes that make up the PET Plant include:

1. Raw and finished material receiving, handling, storage, and shipping
2. PTA Production Unit Processes
3. PET Production Unit Processes
4. Shared Processes: Heat Transfer Fluid Heaters, Wastewater Treatment system, and Cooling Tower system.

At the conclusion of this section (Section VI), we will provide a summary of the GHG emitting sources and processes.

1. Raw and finished material receiving, handling, storage, and shipping

There are no direct GHG emissions from any of these processes, other than fugitive equipment leaks from piping components. The materials handling to and from the plant include the following:

Tank Farm: The tank farm will include the following tanks:

- 2 tanks for Ethylene Glycol (EG)
- 5 tanks for p-xylene
- 1 DEG tank
- 1 acetic acid tank
- 1 caustic storage tank
- Aqueous ammonia storage - used in the SCR NO_x control of the 4 heaters

The tank farm will be provided with a water scrubber for the treatment of gaseous emission from the tanks during normal operation. Similarly to all the other scrubbers of the plant, the liquid stream from the tank farm scrubber is sent to the wastewater plant for further treatment.

Dock: The plant will access a dock that will be owned and operated by the Port of Corpus Christi Authority. Current plans include receipt of raw material from the barges at the dock. No loading of barges is planned.

Rail Yard: The rail yard serving M&G plants will be provided with:

- 3 unloading stations for PTA which will be used only in case of unavailability of PTA from the M&G PTA production plant. Unloading will be closed loop with nitrogen conveying.
- 1 unloading station for isophthalic acid (IPA). Unloading will be closed loop with nitrogen conveying.
- 2 unloading stations for internal PET handling operations (off specs, rework material).
- 2 shipping silos for PTA and a rail car loading air filter system.
- 5 shipping silos for PET and a rail car loading air filter system.
- 3 additional silos for internal PET handling operation (off specs, rework material).
- Unloading stations for liquid diethylene glycol (DEG), Acetic Acid and monoethylene glycol (MEG).

Inbound and Outbound: Regarding the receipt of raw materials and chemicals at the site:

- P-xylene will be received by ship/barge.
- Acetic acid arrives mainly by rail (a truck unloading station is also provided).
- Ethylene glycol will be received by barge (a backup rail car unloading station is also provided).
- IPA will be received by rail and pneumatically conveyed to the PET unit production process (a backup container unloading station is also provided).
- DEG arrives mainly by rail (a backup truck unloading station is also provided).
- Other raw materials will arrive at site by truck or container.

Conveying Air: PET chips are conveyed within the plant units and to/from the rail yard using a network of pneumatic conveying systems. For this purpose, ambient air is filtered and then pressurized at the desired value using oil-free, water cooled centrifugal compressors.

The sales product silos operate deduster systems in the loading lines below each silo to remove fines from the product during loading operations. Air is blown counter current to the falling product to mobilize fines (dust) and transport it to the deduster bag houses for control. The dedusters are part of normal loading operations to assure the product meets the low dust content specifications. The dedusting operation is not always needed for the off-spec silo loading operations.

Conveying Nitrogen: As will be described below, PTA and IPA powders are conveyed within the plant units and to/from rail yard using a network of pneumatic conveying systems operated with nitrogen. These systems resemble the ones used for the PET, however, unlike conveying air, nitrogen used for conveying is not vented to the atmosphere. For this reason, after conveying and separation of PTA/IPA dusts, nitrogen is filtered, cooled and recycled back to the compressors in a closed loop.

2. PTA Unit Process Description

The terephthalic acid (PTA) process uses para-xylene and air as major feedstock for producing PTA. PTA is a primary raw material used to produce PET (polyethylene terephthalate) in M&G's proposed downstream PET unit. The proposed PTA process consists of the following process systems:

- a. Process Air and Off-gas
- b. Crude PTA production
- c. Digestion
- d. Crystallizer
- e. Flash Cooling
- f. Filtration and Drying
- g. Vacuum Unit

Specifically, the PTA process consists of the following GHG emitting emission units: two RTOs where the organic volatile compounds and residual carbon monoxide (CO) in the waste gas stream are oxidized to carbon dioxide and an associated waste gas scrubber system to convert residual bromine-containing species (methyl bromide) in the off gas (waste gas) before it is vented to the atmosphere (EPNs: E1 and E2), and fugitives (EPN: FUGPTA)

a. PTA Unit Process Air, Off-gas and Crude PTA Production processes

The PTA oxidizer serves as the primary reactor for converting p-xylene to PTA. Air from the main air compressor is injected to provide reaction oxygen and agitation, while p-xylene is fed to the reactor from one of the floating roof tanks located in the tank farm.

After the feed p-xylene and the air from the main compressor react in the oxidizer and post oxidizer to produce PTA, the exiting vapors stream is sent to the base of the water removal column (WRC). The WRC is the primary means of water removal from the PTA process. The oxidation reactions in the oxidizer are exothermic and the heat of reaction vaporizes acetic acid, water and low boiling compounds. This vapor, along with nitrogen, unreacted oxygen and lesser amounts of carbon monoxide and carbon dioxide, is fed to the WRC where water is separated from the acetic acid.

The hot vapor exiting the water removal column is superheated in off gas preheater and then routed to the expander for energy recovery. The expander, together with a steam turbine, drives the main air compressor and a power generator for the plant.

The WRC overhead vapor is finally cooled down and condensed such that it can be pumped back to the top of the column as reflux. The WRC non-condensable overhead vapor is sent to the off-gas treatment unit [(system of two RTOs where the organic volatile compounds and residual carbon monoxide (CO) in the waste gas stream are oxidized to form carbon dioxide (CO₂)]. The main purpose of regenerative thermal oxidation is to destroy CO and hydrocarbons. In addition, an associated waste gas scrubber system is designed to convert residual bromine-containing species (methyl bromide) in the off gas (waste gas) before it is vented to the atmosphere (EPNs: E1, E2).

In addition to the primary feed from the oxidizers, the WRC will receive digester and crystallizer off-gases (a high pressure vaporized mixture of acetic acid and water) used to increase the enthalpy input to the WRC, thereby increasing acetic acid/water fractionating capacity.

During normal operations, the heat release of the waste off gas fed to the RTO is sufficient for the RTO to operate auto thermally, i.e. supplementary heat input is not required. Should the off gas heat release periodically decrease, natural gas will be supplied to the RTOs to sustain proper firebox temperature.

b. PTA Unit Digestion process

The post oxidizer slurry underflow (water column underflow) is pumped to the digester where the reactions of partially oxidized products of p-xylene (i.e., p-toluic acid and 4-carboxybenzaldehyde (4-CBA)) to terephthalic acid result in a higher overall conversion. Hot acetic acid vapor, from the acid vaporizer is injected to the digester to maintain the temperature and pressure. The acetic acid vapor is injected directly into the digester to raise the temperature of the slurry to promote dissolution and re-crystallization of the PTA. The excess underflow is cooled in a train of heat exchangers and steam generators for energy recovery.

c. PTA Unit Crystallizer process

Following the post digester the slurry is crystallized at oxidation pressure in the crystallizer. The crystallizer is agitated to maintain a solids suspension. The off-gas from the crystallizer is vented back to the respective WRCs.

d. PTA Unit Filtering and Drying process

After crystallization, the product slurry is flash-cooled and sent to the PTA filters which separate the PTA from the acetic acid/catalyst liquid. The wet PTA cake is kicked off the filter into the respective PTA dryers, which are heated by steam. No air is introduced to this drying system.

The dried PTA powder falls from the drier discharge while vaporized acetic acid is removed through the (dryer) filter vent scrubber system. Overheads from the scrubbing system are routed to the RTOs (EPNs: E1, E2). A stream from the filtering and drying section containing solid wastes is sent to the wastewater treatment plant (WWTP).

From the dryer, solid PTA is pneumatically conveyed to silos and from there either to the PET plant or to the PTA silos located in the rail yard for further loading into railcars and carriage by rail. An off-spec silo located in the PTA unit process area is used to store off-spec material for further re-processing. All the pneumatic transport systems of the PTA unit are operated using nitrogen in a closed loop.

e. PTA Unit Processes: GHG Emissions

The feed streams to the RTOs include the WRC non-condensable overhead vapor, and emissions from the digestion and crystallization process and are the primary source of GHG from the PTA process, with the balance of GHG being from natural gas pipe fugitive emissions. The combined streams fed to the RTO for destruction is comprised primarily of nitrogen (84.4 wt %), water (10.3 wt %), oxygen (3.5 wt %), CO₂ (1.2 wt %), and methyl bromide (0.02 wt %). The exhaust stream from each RTO is expected to be primarily nitrogen (83%), water (12%), oxygen (3.5%), and CO₂ (2%). As stated previously, while the heating value of the waste streams treated by the RTO are sufficient in most cases to keep the RTOs operating without supplemental fuel, the RTOs are fired or supplemented with natural gas in order to maintain the destruction efficiency needed to control the VOC and CO in the waste stream, which is the purpose of the RTOs. CO₂e emissions from the RTOs comprise approximately 10-12% of the CO₂e emissions from the site.

3. PET Unit Description

The new PET Unit will produce PET using PTA and ethylene glycol (EG) as primary feedstocks and the following other additives: catalyst, diethylene glycol (DEG), inhibitor (phosphoric acid), FeP (iron phosphide), toner and isophthalic acid (IPA). The PET production process consists of two main process units: a continuous polymerization (CP) unit and a solid state polymerization (SSP) unit, some shared units such as the Heat Transfer Fluid Heaters and the wastewater treatment system, and some raw and finished material handling processes.

Neither the CP nor the SSP process units emit GHG directly, but their operation is described in detail in order to demonstrate how energy efficiency is practiced within these units and how various waste gas streams are routed for thermal destruction, typically within the heat

transfer fluid heaters, which does result in GHG emissions. The PET Unit consists of the CP Unit and the SSP Unit as follows:

- a. PET Unit CP processes include:
 1. Additive and feedstock preparation
 2. Esterification
 3. Prepolymerization
 4. Polymerization
 5. Filtration and cutting
 6. Scrap Recovery
 7. Vacuum Unit process
- b. PET Unit SSP processes include:
 1. Pre-crystallization and crystallization
 2. Solid state polymerization reaction
 3. Cooling process and product handling
 4. Gas Treatment Unit (GTU)

Each of the above processes are described here.

- a. PET Unit CP Processes.
 1. Additive and feedstock preparation process. In this unit, the main feedstock materials, PTA and EG are mixed together to produce a slurry which is then fed to the following esterification unit. This system includes the equipment required for the additive preparation. Except for DEG, all additives need to be premixed with EG, which takes place in a series of independent preparation/mix vessels (one for each additive) and one or more feeding vessels.
 2. Esterification process. In the esterification unit, the PTA contained in the slurry coming from the feedstock preparation unit is preheated for the reaction with EG in the esterifier by increasing the temperature of the slurry in a heat exchanger using HTF (heat transfer fluid).

The reaction between PTA and EG yields an oligomer (short-chain polymer) and water as products of the reaction. Water is removed from the system in a tray column. The column bottoms are sent to the OSC and then on to the WWTP. The water-free oligomer is transferred to the prepolymerization unit described below. It should be noted that downstream of this point in the process, the process stream is divided into two parallel independent lines (CP lines 1 and 2, and SSP lines 1 and 2).

Following the esterification unit, each of the two CP lines is comprised of one prepolymerizer, one polymerization reactor (Finisher) and one set of filtering and cutting machines.

Process vents from the column are collected, along with other process vents coming from the Vacuum Pump Unit described below, and bubbled into a seal pot (esterifier seal pot) equipped with a scrubber. The vapor stream from the scrubber is directed to the HTF process heaters (EPNs E7A-D), as part of the combustion air, for thermal destruction of organics contained herein, from which GHG emissions originate, and

by doing so, slightly reduce the amount of natural gas required to be used in the HTF heaters, as described in the "Process Heaters" section below.

3. Prepolymerization process. In the prepolymerization unit, the esterification reaction started in the previous unit is completed and the polymerization reaction starts to form the prepolymer (a precursor of the final desired polymer). The unit is comprised of a heat exchanger and a reactor equipped with special internals and heating jacket.

Before entering the prepolymerization unit, additives prepared in the feedstock and additive preparation unit, are introduced with the oligomer stream (from the esterification unit). From the prepolymerization onward, all equipment is maintained under vacuum conditions which are required to promote the reaction and to remove the reaction side products.

Vacuum is maintained through a system of ethylene glycol vapor ejectors followed by a vacuum pump in common for all equipment of a CP line. In the prepolymerization unit, sealing against atmosphere of equipment working under vacuum is guaranteed through barometric legs terminating into a vessel (one per line), conventionally called "hot wells". The hot wells contain ethylene glycol which is maintained under level control at ambient conditions.

4. Polymerization process. In the polymerization unit, the polymerization reaction is completed in the reactor (Finisher) working under vacuum. Just as in the prepolymerization unit, in the polymerization unit, sealing against atmosphere of equipment working under vacuum is guaranteed through barometric legs terminating into a vessel (one per line) containing ethylene glycol. These vessels are conventionally called cold wells; however they operate at ambient conditions under level control.
5. Filtration and Chip Formation process. Normally, molten polymer from the finisher is divided and pumped to a set of filters and chip making machines where chips of polymer are formed. During instances of generating off-spec material or during periods of SSP line outage, the molten polymer is routed to air coolers and thence to the off-spec silo. In the chip making machines, chips of amorphous PET (also called base resin) are formed by simultaneous cutting and quenching of molten polymer strands with water.

The chip making machine is also equipped with a centrifugal air dryer for the separation of the bulk of water used during the chip formation and final drying of chip. From the dryer, chips are then fed to a classifier for the removal of oversized material and pneumatically conveyed to the intermediate storage (amorphous) silos. Amorphous PET chips stored in silos are the feedstock for the SSP unit.

6. Scrap Recovery process. This unit is designed to recover scraps coming from the PET production plant (both from CP and SSP) and further recycling in the process.
7. Vacuum Unit process. Vacuum conditions in each CP line are maintained through a system of ethylene glycol vapor jet ejectors with three inter-condensers and a liquid ring vacuum pump. Vapor streams from the liquid ring pump bubble into the

esterifier seal pot as described above. Ejectors will be operated with ethylene glycol vapor as motive fluid. There will be a total of 2 independent vacuum systems: one per CP line. Sealing against atmosphere of inter-condensers working under vacuum is guaranteed through barometric legs terminating into a vessel (one per line), called a "glycol seal tank", which contains ethylene glycol. The glycol seal tank is integrated in the ethylene glycol distribution system within the CP unit (as well as the hot and cold wells described above) and is under level control.

b. PET Unit SSP Processes.

In the Solid State Post-Poly-Condensation (SSP) unit the molecular weight of PET amorphous chips is increased and byproducts (mainly water, EG and acetaldehyde) are removed in order to make a final polymer mechanically and chemically suitable for the end user. The process is performed by precrystallization, crystallization and SSP reaction steps.

Byproduct organic compounds released during the crystallization and solid state polymerization are conveyed from reactors by nitrogen inert gas. Then, the inert gas goes to the Gas Treatment Unit (GTU) where byproducts are oxidized in the presence of a catalytic bed. The water vapors released during reactions and catalytic oxidation are subsequently condensed and absorbed in drying molecular sieved driers, while the clean gas is returned back to the process.

1. Pre-Crystallization and Crystallization process. Amorphous PET chips at ambient temperature are conveyed from the intermediate PET amorphous silos to the pre-crystallization unit which comprises of a fluid bed heater. In this unit, chips are heated using hot air as heating and fluidizing media. The air coming out from the bed passes through multi-cyclones and a filter for the removal of PET fines. The clean air is then circulated back (in closed loop) to the fluid bed heater while powders recovered from multicyclones and filter are recovered and re-processed.

Liquid HTF (in the form of Therminoll 66 or equivalent) is used to heat the fluidization air. A portion of the filtered air is continuously purged from the closed circulation loop and sent to HTF process heaters (EPNs E7-A thru D) to avoid accumulation of undesired contaminants released during heat of amorphous PET chips.

The semi-crystallized product coming out of this bed enters then into another fluid bed: the crystallizer. In this second fluid bed, the partially crystallized product reaches a certain degree of crystallization and reaches the temperature required for the following solid state reaction in the SSP reactor.

The process gas for the crystallizer is nitrogen and not air anymore. The fluidizing nitrogen leaving the fluid bed passes through multi-cyclones and a filter. Then, it is heated and sent back to the crystallizer in closed loop. Part of this gas is continuously purged from the closed circulation loop and sent to the GTU (Gas Treatment Unit) for removal of by-products. This purge avoids the build-up of undesired contaminants released during the crystallization process and the following solid state polymerization.

After removal of by-products, the clean gas leaving the GTU is then heated up, sent to the SSP reaction unit, where it is used to remove by-products herein produced and finally sent back into the closed loop of the crystallizer. A continuous make-up of nitrogen from outside the unit is provided to compensate unavoidable nitrogen losses of the closed loops. Chips leaving the crystallizer enter then the SSP reactor.

2. Solid State Polymerization Reaction process. This section is comprised of a horizontal inclined rotating cylinder (SSP reactor) in which inert gas is flowing counter-currently with respect to the flow direction of the chips. The main reaction taking place in the SSP reactor is the polycondensation of PET polymer chains, leading to increased PET molecular weight, up to the desired level. Some side reactions, similar to the ones occurring in the crystallization steps, take place in the SSP reactor. The removal of these volatile reaction by-products is accomplished with nitrogen inert gas coming from the GTU, as described in the previous section.
3. Cooling process and product handling. After polycondensation in the SSP reactor, chips are cooled in a fluidized bed that is operated with air. The cooled chips are finally pneumatically conveyed with air to a pair of quality evaluation silos for each SSP line and from here to the SSP (product) silos located in the rail yard for further loading into railcars. On demand, a portion of chips can be also sent to a bagging unit equipped with buffer storage and a bagging machine. In the bagging unit, chips are charged into bags, which in turn are loaded into trucks.
4. Gas Treatment Unit (GTU). In this section of the plant, a portion of nitrogen from the crystallizer loop is treated to remove the entrained hydrocarbons and moisture. The gas is heated and sent to a catalytic bed reactor, where oxidation of volatile organic compounds coming from the crystallization and SSP reaction units takes place.

The oxidation reaction water, along with the water coming from the crystallization and SSP reaction units is adsorbed on molecular sieve type driers. The adsorbent material is then regenerated by a flow of hot, dry inert gas, and the water is separated from this gas by condensation. The unit is made of two molecular sieve fixed beds, operating in "sweep" mode: one under operation and one under regeneration.

After removal of by-products, the clean gas leaving the GTU is then heated up, sent to the SSP reaction unit, where it is used to remove by-products therein produced and finally sent back into the closed loop of the crystallizer. A continuous make-up of nitrogen from outside the unit is provided to compensate for unavoidable nitrogen losses of the closed loops.

4. PET Unit Shared Processes

There are some processes that are shared or made use of by several of the process units described above. These shared processes include:

- a. Heat Transfer Fluid heaters
- b. Wastewater treatment
- c. Cooling towers and blowdown treatment

These shared processes are described as follows:

- a. Process Heaters and Heat Transfer Fluid (HTF) Distribution Systems (EPNs: E7-A thru E7-D). The heat input required by the CP and SSP units is provided through Dowtherm A (or equivalent) heat transfer fluid which is vaporized in four process heaters (EPN: E7 A-D). The heaters will fire natural gas as well as methane-rich biogas collected from the waste water treatment plant during normal operations. In addition, the heaters will also combust vapors from the organic stripping column (OSC) as well as vapors from the esterification unit seal pot.

The HTF (in the form of Dowtherm A or equivalent) is stored in an atmospheric storage tank vessel in the CP unit. Users located in the CP unit utilize Dowtherm A directly, either as vapor or condensed hot liquid, which is distributed through a dedicated system. Non-condensables of HTF distribution system are removed through a liquid ring vacuum pump.

In the SSP unit, whenever heat is required, it is given through another heat transfer fluid (Therminoll 66 or equivalent) in liquid phase. The Therminoll 66 circulating to/from SSP users is heated in a heat exchanger using condensing Dowtherm A at higher temperature and distributed to SSP unit users with a separate HTF system independent from the primary system operated with Dowtherm.

Before venting to the atmosphere, the heat of the hot flue gases leaving the HTF heaters is recovered to generate low pressure steam used within the PET plant. Low pressure steam is used to remove part of the organics contained in the waste waters coming from the PET plant by stripping, in the OSC. Stripped organics are then sent back to HTF heaters for thermal destruction. The stripped waste water stream is sent to the WWTP.

- b. Wastewater Treatment Plant (WWTP). Wastewater from the PET and PTA units and other areas of the complex are collected and combined in a mixed equalization tank. Once equalized, the wastewater is pumped to an anaerobic system where the resident biomass will effectively remove the bulk of the organics and produce methane gas. The gas will be collected and recovered for use as fuel gas in the process heaters (EPNs: E7A-D). During periods of heater maintenance or plant turnaround and when excess biogas is produced, biogas will be flared in a low pressure flare (EPN: Flare) located at the WWTP.

The wastewater will flow to an aerobic mixed bed biological reactor where the remaining organics are reduced by aerobic bacteria that exist as a fixed film on free-floating plastic media. The tank is aerated with medium bubble diffusers utilizing blower air. This air provides both the oxygen necessary for biological degradation as well as the energy for mixing.

- c. Cooling Towers and Blowdown Treatment. The site will be equipped with a cooling tower comprised of 10 modules, which will supply cooling water to both the PET plant and the Utility Plant. A continuous make-up with treated water coming from the treated water storage tank is used to replace losses of the cooling tower system (drift and evaporation losses and brine reject from the cooling tower blow down treatment unit).

VI. B. PET Plant Design/Equipment Considerations

Overall Energy-Efficient Design Philosophy

To minimize GHG emissions, M&G is incorporating design and equipment selection approaches in the proposed PET plant design that will result in reduced energy use and conservation of materials. This design strategy will also lower operating costs in the entire plant and at upstream electric generation sources. Some examples of the type of energy efficiency design features that are included in the PET plant design are described in this section below.

Process Design Selection

There are several technologies available for the manufacture of PET. M&G is proposing to select a PET process that features a single-step esterification in the continuous process (CP unit). This technology eliminates a second esterification step found in traditional CP units in PET plants and reduces the total energy required during the esterification unit operation by reducing the number of heated vessels, which minimizes the quantity of ambient heat losses.

M&G is also proposing to construct a solid state process (SSP) unit that eliminates the precrystallization and crystallization steps found in traditional SSP units. By eliminating these unit operations at the front end of the SSP process, the overall SSP unit throughput can be increased by up to threefold (as compared to a traditional SSP unit) which corresponds to significant energy (heat and electricity) savings.

Waste Energy Recovery

The PTA unit will have two turbo expanders that receive hot vapor from the water removal columns. The expanders drive each main PTA unit air compressor via steam turbine and feed power generators for the PTA unit. The electricity produced is sufficient to meet approximately 50% (+or – 5%) of the total plant electricity demand under 100% operating conditions.

Electrical Equipment Selection

The PET plant design specifies that all new, high-efficiency electrical equipment be installed for the efficient conversion of electrical energy into mechanical energy, thus minimizing the amount of electrical energy needed and associated emissions of GHGs at upstream generation sources (e.g., combined cycle gas turbine).

Energy-saving motors will be installed on all applicable compressors. Capacity control will be installed to reduce electric energy consumption while running the compressor at a lower load. Variable speed controllers will be installed for blowers, compressors and pumps to optimize electricity consumption.

VI. C. PET Plant GHG Sources Summary

Biogas Recovery and Reuse

M&G will collect methane-rich (67 mole %) biogas generated from the WWTP to be used as fuel in the four HTF heaters (EPNs E7-A thru –D). This approach will minimize potential GHG emissions associated with the continuous venting of biogas. It will also reduce the amount of imported fuel (natural gas) supplied to the plant. The biogas may need to be flared periodically through the low pressure flare (EPN: Flare). Instances of flaring will include certain operating scenarios such as heater maintenance or startup, or plant turnaround. The

flare will be equipped with a natural gas pilot. Flaring of the biogas stream results in emissions of GHGs, as does the natural gas consumption needed to maintain the flare pilot flame.

Heat Transfer Fluid (HTF) Heaters (EPNs: E7-A through E7-D)

The HTF Heaters are fired primarily with natural gas, however the following process streams are fired as fuel gases in the heaters to recover residual heating value and decrease overall natural gas usage: biogas stream (from the waste water treatment plant), Organic Stripping Column (OSC) stream, and the Esterification Column (EC) stream. These fuel gas streams can be routed to any one of the heaters at any time. The HTF heaters are responsible for 28% of the GHG emissions at the site.

Regenerative Thermal Oxidizers (RTOs) (EPNs: E1 & E2)

The RTOs will abate VOC and CO emissions from various process streams in the PTA unit. The RTOs will emit GHGs as a result of waste gas and fuel gas combustion (EPNs: E1, E2), and the waste gas stream ordinarily is expected to have a sufficient heat content such that supplemental natural gas fuel use will be minimized. The RTOs will achieve 98-99 % VOC destruction and removal efficiency as described in the non-GHG state/ PSD permit application submitted to the TCEQ by M&G Resins. The destruction efficiency of methane is 99%. The RTO exhaust stream includes GHG contributions from the reactor process and from the oxidation of carbon containing species in the RTO.

As stated previously, both RTOs will supplementally fire natural gas as fuel to keep the units at proper VOC destruction temperature. The RTO low CO₂ concentration exhaust stream (approximately 2%) accounts for about 10% of the CO₂ emissions from the site.

Emergency Generator Engines (EPNs: ENG-1, ENG-2) and the Emergency Firewater Pump Engines (EPNs: ENG-3, ENG-4)

The emergency generator engines and the emergency firewater pump engines combust diesel fuel and are sources of GHG emissions. The emergency engines will be limited during non-emergency operating hours to testing and readiness checks as it is subject to 40 CFR Part 60 Subpart IIII.

Piping Fugitives (EPNs: PTAFUG and PETFUG)

Natural gas, biogas and other process streams contain GHGs and they get emitted from piping system components as fugitives. Natural gas is delivered to the site via pipeline and will be metered and piped to the RTOs and heaters. Biogas will be collected at the WWTP and routed to the heaters. Fugitive GHG emissions from the piping components will include emissions of methane (CH₄) and carbon dioxide (CO₂).

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit were conducted in accordance with EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines the steps for conducting a "top-down" BACT analysis. Those steps are listed below.

- (1) Identify all potentially available control options;
- (2) Eliminate technically infeasible control options;
- (3) Rank remaining control technologies;
- (4) Evaluate the most effective controls and document the results; and,
- (5) Select BACT.

VIII. Applicable Emission Units and BACT Discussion

The majority of the contribution of GHGs associated with the project is from combustion sources (i.e., heat transfer fluid heaters, biogas flare, regenerative thermal oxidizers, emergency diesel generators and fire water pump diesel engines from the PET Plant, and the gas turbines and boilers from the Utility Plant). The site has some fugitive emissions from piping components which contribute an insignificant amount of GHGs (see Table 1a, above). These stationary combustion sources primarily emit products of combustion including carbon dioxide (CO₂) at a volumetric flow rate of from 2 (heaters and RTOs) to approximately 8% (boilers), and small amounts of nitrous oxide (N₂O) and methane (CH₄). Carbon dioxide accounts for approximately 99.5% of the CO₂e emissions at the entire site (all but approximately 6,600 tpy CO₂e of the worst case sitewide total of 1,178,441 tpy CO₂e), therefore this BACT analysis addresses primarily CO₂ emissions control.

As described above, and stated in Table 1 above, the PET plant accounts for approximately 37-41% of the sitewide GHG emissions. As stated previously, the following GHG sources are part of the PET Plant, which is the scope of this GHG PSD permit:

- Heat Transfer Fluid (HTF) Heaters 1-4 (EPNs: E7-A, E7-B, E7-C, E7-D)
- Biogas Flare (EPN: Flare)
- Regenerative Thermal Oxidizers (RTOs) 1 and 2 (EPNs: E1, E2)
- Emergency Diesel Generators 1 and 2 (EPNs: E85-A, E85-B)
- Fire Water Pump Diesel Engines 1 and 2 (EPNs: E87-A, E87-B)
- Plant Fugitives (EPNs: FUGPTA and FUGPET)

The following sources are *not* part of this permit, but contribute approximately 58-63% of the GHG emissions from the site. These sources, collectively named the "Utility Plant", are a collocated support facility to the PET Plant. The Utility Plant is comprised of either a combined heat and power facility (under Option 1) or a steam plant (under Option 2). The Utility Plant is to be authorized in the proposed GHG permit PSD-TX-1354-GHG and is fully described in the associated statement of basis for that proposed PSD permit. These sources are briefly described here because they will be taken into account in evaluating carbon capture and sequestration as an add-on GHG control option for this site. The sources include:

- Natural gas fired 49 MW GE LM6000 with HRSG combustion turbine (EPN: CTG, Part of Option 1)

- 445 MMbtu/hr natural gas fired Auxiliary Boiler A1 (EPN: AUXBLR A1, Part of Option 1 and Option 2)
- 445 MMbtu/hr natural gas fired Auxiliary Boiler A2 (EPN: AUXBLR A2, Part of Option 2)
- 250 MMbtu/hr natural gas fired Auxiliary Boiler B1 (EPN: AUXBLR B1, Part of Option 1 and Option 2).
- Fugitive Equipment leak related emissions from natural gas fuel piping components (EPN: NG-FUG, Part of Option 1 and Option 2)
- Fugitive emissions from natural gas fuel line blowdowns related to maintenance, startup, and shutdown (EPN: MSS-FUG, Part of Option 1 and Option 2)

BACT Analysis for Heat Transfer Fluid (HTF) Heaters (EPNs: E7-A, E7-B, E7-C, E7-D)

The heat transfer fluid (HTF) heaters accounts for approximately 67% of the CO₂ emissions from the PET plant and 28% of the site-wide CO₂ emissions. Fired primarily by natural gas, but also co-firing waste gas (either directly as fuel (biogas) or as part of combustion air (waste gas)), the heaters have a stack effluent CO₂ content of approximately 2%.

Step 1: Identify All Available Control Technologies

1. Carbon Capture and Storage (CCS) – CCS is an available add-on control technology that is applicable for all of the site's combustion units. Comparatively, CO₂ emissions contribute the most volume (greater than 99%) to the overall emissions; therefore, additional analysis is not required for CH₄ and N₂O.
2. Efficient Combustion Operation, and Maintenance – The use of oxygen trim control to assist in maintaining optimal combustion operating conditions. Ongoing maintenance includes periodic heater tune ups to assure that the burners operate at maximum efficiency and periodic maintenance on heat transfer surfaces to assure ongoing efficient heat transfer.
3. Waste Heat Recovery – The use of economizers on the heater exhaust stack will capture heat from the exhaust stream and use it to produce low pressure steam for use in the process.
4. Minimizing Fouling of Heat Exchange Surfaces - To minimize fouling, filtration of the inlet air to the combustion turbine is performed. Additionally, cleaning of the tubes is performed during periodic outages.
5. Lower GHG generating fuels. The use of methane or waste gas fuels that are lower in carbon content relative to other fuels, such solid fossil fuels.

Step 2: Eliminate Technically Infeasible Options

All options identified in Step 1 are considered technically feasible for this project.

1. Add on Controls: CCS.

Carbon capture and storage is a GHG control process that can be used by “facilities emitting CO₂ in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO₂ streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing).”³

CCS: Capture. CCS systems involve the use of adsorption or absorption processes to remove CO₂ from flue gas, with subsequent desorption to produce a concentrated CO₂ stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion. Of these approaches, pre-combustion capture is applicable primarily to gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen. At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine applications (the largest GHG emitting source at the site) and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances. Accordingly, pre-combustion capture and oxyfuel combustion are not considered available control options for the proposed facility; the third approach, post-combustion capture, is applicable to combustion turbines and potentially to other post combustion flue gas streams at the site.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO₂ from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation. Many of these methods are either still in development or are not suitable for treating power plant flue gas due to the characteristics of the exhaust stream.⁴ Of the potentially applicable technologies, post-combustion capture with an amine solvent such as monoethanolamine (MEA) is currently the preferred option because it is the most mature and well-documented technology and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes.⁵

In a typical MEA absorption process, the flue gas is cooled before it is contacted counter-currently with the lean solvent in a reactor vessel. The scrubbed flue gas is cleaned of solvent and vented to the atmosphere while the rich solvent is sent to a separate stripper where it is regenerated at elevated temperatures and then returned to the absorber for re-use. Fluor’s Econamine FG Plus process operates in this manner, and it uses an MEA-based solvent that has been specially designed to recover CO₂ from oxygen-containing streams with low CO₂ concentrations typical of gas turbine exhaust.⁶

M&G cites to Alstom, one of the major developers of commercial CO₂ capture technology using post-combustion amine absorption, post-combustion chilled ammonia

³ U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <<http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf>>

⁴ A Review of CO₂ Capture by Absorption and Adsorption by Cheng-Hsiu, et. al. In *Aerosol and Air Quality Research*, 12: 745–769, 2012. Available here: http://aaqr.org/vol12_no5_october2012/7_aaqr-12-05-ir-0132_745-769.pdf Last accessed September 24, 2014.

⁵ A comparison of different parameter correlation models and the validation of an MEA-based absorber model by Kvamsdal, et. al, (2011). *Energy Procedia*, 4, 1526-1533.

⁶ Fluor Corporation. (2009). Econamine FG Plus Process. Available here: <http://www.fluor.com/econamine/Pages/efgprocess.aspx>. Last visited September 24, 2014.

absorption, and oxy-combustion, states on its web site⁷ that its CO₂ capture technology will become commercially available in 2015. However, the company does not indicate whether such technology will be available for capture of CO₂ emissions generated from chemical plant sources, like those included in this project.

Over 99% of the candidate CCS source vent gas streams in Project Jumbo are post combustion flue gas streams from the combustion of either natural gas, biogas, or process waste gas or a combination of these and thus are dilute in CO₂ concentration (ranging from about 2% for the RTOs of the PET Plant to approximately 8.4% for the steam boilers of the Utility Plant) while typical amine treatment systems for coal fired power plants would treat post combustion flue gas streams that range in the 3 to 15% CO₂ by volume range. These post combustion emissions streams may contain other products of combustion such as PM, NO_x and SO₂, thus increasing the challenge of CO₂ separation for the project.

M&G indicates, and the EPA recognizes, that although amine absorption technology for CO₂ capture has routinely been applied to processes in the petroleum refining and natural gas processing industries it has not been applied commercially to process vents at large chemical manufacturing plants⁸.

CCS: Compression and Transport. Once separated from the flue gas stream, the CO₂ will need to be transported to its ultimate storage location. Unless the final storage location is nearby, the efficient transportation of a CO₂ stream will require that the stream be compressed to the supercritical fluid state for transportation in high pressure pipeline⁹. While energy and resource intensive, obtaining right-of-way, constructing, and operating such a pipeline is technically possible. While there are many factors that enter into the cost and operation of such a pipeline, the final cost of such a pipeline is directly related to its size and length.¹⁰

CCS: Storage. Specific types of geologic formations capable of receiving and permanently storing CO₂ are the target long term storage reservoirs for CO₂ streams. CO₂ floods have been used in enhanced oil recovery (EOR) operations for decades. Essentially EOR operations inject CO₂ under pressure through multiple injection wells in an existing suitable oil field producing zone. When injected, the CO₂ aids in the flow of oil to producing oil wells that are located on the other end of the oil field area. CO₂ recovered with the produced oil is then recirculated back to the injection wells for reinjection. Such geologic formations have characteristics that allow the CO₂ to remain in the oil field producing zone for extended periods of time, and perhaps permanently.

⁷ Website: Alstom's carbon capture technology commercially "ready to go" by 2015.
<http://www.alstom.com/press-centre/2010/11/ccs2015/> last accessed July 9, 2014.

⁸ Report of the Interagency Task Force on Carbon Capture and Storage, page 50 (Aug. 2010). Available here:
<http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf>. Last visited on September 24, 2014.

⁹ The U.S. Department of Energy's National Energy Technology Laboratory webpage on CO₂ Compression.
<http://www.netl.doe.gov/research/coal/carbon-capture/co2-compression> (last visited September 24, 2014)

¹⁰ Carbon Dioxide Transport and Storage Costs in NETL Studies. DOE/NETL-2013/1614. Final Report March 14, 2013 available here:
http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/QGESS_CO2T-S_Rev2_20130408.pdf

Multiple studies are underway to characterize the suitability of potential sequestration sites in various locations within Texas and in the Southeast. The Gulf Coast Carbon Center, a part of the Bureau of Economic Geology in Texas is one such organization currently involved in site characterization at various locations in Texas.¹¹

While no South and Southeast Texas EOR reservoirs or other nearby geologic formations have yet been technically demonstrated to be suitable for large-scale, long-term CO₂ storage, the W.A. Parish Post Combustion CO₂ Capture and Sequestration Project, funded partially by the Department of Energy, is proposing to use CO₂ captured from an exhaust stream from a 250 MW turbine (Unit 8 of the W.A Parish Plant in Fort Bend county, TX) as part of an Enhanced Oil Recovery (EOR) project at the Existing West Ranch oil field in Jackson County. The West Ranch field is located approximately 100 miles northeast of Corpus Christi, near Vanderbilt, TX¹².

Other locations are currently being studied as potentially long term sequestration sites for anthropomorphic CO₂. The US. Department of Energy has identified the Stacked Storage location in the Cranfield Field Site in Mississippi as one such location¹³. In comparison, the closest site that is currently being field-tested to demonstrate its capacity for large-scale geological storage of CO₂ is the Southwest Regional Partnership (SWP) on Carbon Sequestration's Scurry Area Canyon Reef Operators (SACROC) test site, which is located in Scurry County, Texas.¹⁴ According to M&G Resins, the shortest pipeline distance to the SACROC facility is 441 miles from the M&G site.

While there are some potential long term sequestration sites, none have been demonstrated as available for commercial use.

CCS Overall: While elements of CCS are currently available for commercial use, the technology as a whole has not been demonstrated to be commercially available for use with a project similar to the M&G project. Nevertheless, we do not eliminate the technology entirely on technical grounds; rather, M&G has provided cost and other considerations on implementation of CCS for the combustion sources at the M&G project as a whole, and those will be discussed in Step 4.

2. Efficient Combustion Operation, and Maintenance – oxygen trim control and proper heater operations are both part of the design of these heaters and this are technically available control technology methods.
3. Waste Heat Recovery – the use of economizers on the flue gas from the heaters is part of the plant design, and is this is thus a technically available control technology.

¹¹ See the website for the Gulf Coast Carbon Center, located here: <http://www.beg.utexas.edu/gccc/>

¹² U.S. Department of Energy W.A. Parish Post-Combustion CO₂ Capture and Sequestration Project Draft Environmental Impact Statement Summary September 2012 DOE/EIS-0473D. Available here: http://www.netl.doe.gov/publications/others/nepa/deis_sept/eis-0473d_summary.pdf

¹³ U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory Carbon Sequestration Program: Technology Program Plan, available here: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf, February 2011

¹⁴ See the Bureau of Economic Geology SACROC website here: <http://www.beg.utexas.edu/gccc/sacroc.php>

4. Minimizing Fouling of Heat Exchange Surfaces – the use of periodic maintenance in order to maintain heat exchange efficiency is part of the design of this facility and is thus a technically available control methodology.
5. Lower GHG generating fuels -- this use of methane and waste gas, both lower GHG emitting fuels, is part of the design of this facility and is thus a technically available control methodology.

Step 3: Rank Remaining Control Technologies

1. CCS would reduce CO₂ emissions from the combustion sources by approximately 90%.
- 2-5. Each of these measures are all part of the project design. They are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, ranking is not possible.

Step 4: Evaluation of control technologies in order of most effective to least effective, with consideration of economic, energy, and environmental impacts and document results

1. Carbon Capture and Sequestration. M&G Resins developed a cost analysis and additional impacts analysis for CCS for the site that provides the basis for eliminating the technology in this step of the BACT process as a viable control option based on economic costs. The analysis included the CO₂ streams from all the combustion processes except the flare listed in Tables 1a, 1b, and 1c, above, and not just the Utility Plant sources subject to this specific permit. Their analysis can be seen as Appendix B of the permit application update on March 15, 2014.

According to the application, there are a number of other environmental and operational issues related to the installation and operation of CCS that must also be considered in this evaluation. First, operation of CCS capture and compression equipment would require substantial additional electric power. For example, operation of carbon capture equipment at a typical natural gas fired combined heat and power plant is estimated to reduce the net energy efficiency of the plant from approximately 50% (based on the fuel higher heating value (HHV)) to approximately 42.7% (based on fuel HHV)¹⁵.

To provide the amount of reliable electricity needed to power a capture system, M&G would need to significantly expand the scope of the Utility Plant proposed with this project to install one or more additional electric generating units, which are sources of conventional (non-GHG) and GHG air pollutants themselves. To put these additional power requirements in perspective, gas-fired electric generating units typically emit more than 100,000 tons CO₂e/yr. and would themselves, require a PSD permit for GHGs in addition to non-GHG pollutants.

Likewise, M&G would need to construct a 441 mile long pipeline to the SACROC facility in order to transport the CO₂ for sequestration to suitable locations for long term storage/sequestration. Pipeline costs were also considered in the economic analysis provided in Appendix B of the permit application update on March 15, 2014. Construction of such a pipeline

¹⁵ US Department of Energy, National Energy Technology Laboratory, "Costs and Performance Baseline For Fossil Energy Plants, Volume 1 -Bituminous Coal and Natural Gas to Energy", Revision 2, November 2010

would require procurement of right-of-ways which can be a lengthy and potentially difficult undertaking. Pipeline construction would also require extensive planning, environmental studies and possible mitigation of environmental impacts from pipeline construction. Therefore, the transportation of GHGs for this project would potentially result in negative impacts and disturbance to the environment in the pipeline right-of-way.

As with the capture and transportation costs, M&G Resins provided a cost analysis for the geological sequestration of CO₂ from the site (without any post-processing), which is also provided in Appendix B of the permit application updated dated March 15, 2014.

According to this provided information in that Appendix, the studied CCS control option would use amine stripping of the CO₂ from each emissions stream of the heaters and RTOs from the PET Plant and Option 1 of the Utility project for an approximate 90% reduction in CO₂ emissions from the site. This method was selected even though all emissions are primarily from the combustion of natural gas, with the maximum emissions stream having less than 10% by volume CO₂, and the RTOs having a CO₂ content of approximately 2%, both streams relatively low in concentration which would impede the efficient use of amine stripping. The costs included the construction of an estimated 441 mile pipeline for transportation to and long term storage in the SACROC formation.

CCS Total Cost Estimate. The total capital cost of capture, transportation, and geological sequestration (without pretreatment) is projected to be approximately 1.683 billion dollars, with the CCS control resulting in 41% of the total cost of the project. The annual operating and maintenance costs were estimated to be approximately \$56 million. Thus, the average annual CO₂ control cost, based on a 30-year period and an 8.5% interest rate applied to the capital costs, is estimated to be nearly \$96 million. M&G has determined that the average annual cost effectiveness of the studied control would be \$116.70/ton. At this price, M&G asserts the project would not be economically viable. As stated previously, this case was developed to include not only the heater emissions, but all of the combustion sources at the site with the exception of the flare.

It should be noted that M&G's cost estimation indicated above may understate the actual cost, because it does not include additional costs for the following items that would be needed to implement CCS for the Project (includes the PET Plant and the Utility Plant):

- additional gas conditioning and stream cleanup to meet specifications for final transport and sequestration.
- gas gathering system piping to collect vent gas from sources located in different areas of the plant.
- costs of additional electric generating units required to power the capture and compression system (including design, procurement, permitting, installation, operating and maintenance costs); and,
- cost of obtaining rights of way for construction of a 441-mile pipeline.

These items would require significantly more effort to estimate.

EPA Region 6 reviewed M&G Resins' CCS cost estimates and additional impacts considerations and believes it adequately approximates the cost of a CCS control for this project. The EPA believes that these costs together with the technical limitations described

in the CCS Capture and Sequestration sections above indicate that CCS is not BACT for this project.

2. Efficient Combustion Operation, and Maintenance – The use of oxygen trim control to assist in maintaining optimal combustion operating conditions. Ongoing maintenance includes periodic heater tune ups to assure that the burners operate at maximum efficiency and periodic maintenance on heat transfer surfaces to assure ongoing efficient heat transfer.
3. Waste Heat Recovery – The use of economizers on the heater exhaust stack will capture heat from the exhaust stream and use it to produce low pressure steam for use in the process.
4. Minimizing Fouling of Heat Exchange Surfaces - To minimize fouling, filtration of the inlet air to the combustion turbine is performed. Additionally, cleaning of the tubes is performed during periodic outages.
5. Lower GHG generating fuels. The use of methane or waste gas fuels that are lower in carbon content relative to other fuels, such solid fossil fuels.

Potential control measures 2 through 5 are part of the design of the PET plant heaters, and thus are not eliminated in this step.

Step 5- Selection of BACT

EPA has evaluated M&G's proposed selection of all available energy-efficient design options and operational/maintenance practices presented in Step 1 of their BACT analysis as BACT for the four process heaters (EPNs E7-A thru E7-D). Since the proposed energy efficiency design options, described in Step 1 above, are not independent features but are interdependent and represent an integrated energy efficiency strategy, EPA is proposing a BACT limit for each heater which takes into consideration the operation, variability and interaction of all features in combination.

A holistic BACT limit which accounts for the ultimate performance of the entire unit was chosen, rather than individual independent subsystem performance. Otherwise, monitoring and maintaining energy efficiency would be unnecessarily complex because the interdependent nature of operating parameters means that one parameter cannot necessarily be controlled independently without affecting the other operating parameters.

M&G has proposed the metric of a maximum flue gas temperature of 320 °F averaged on a 365-day rolling average basis. M&G will monitor the heaters' flue gas exhaust temperature in accordance with permit conditions. Based on our independent review, EPA has selected this value as an indicator of process efficiency, in addition to annual CO_{2e} emissions limitations on the heaters.

M&G also proposes to use low-emitting, low-carbon fuel by limiting natural gas usage by designing the heaters to fire fuel gas streams generated in the plant such as biogas, OCS and EC streams. M&G is also proposing routine heater maintenance. Limiting the lb of CO₂ generated per MMBtu heat input to 116.9 lb CO₂/MMBtu on a rolling 365-day basis also assures that the units continue to operate efficiently. The EPA has determined that the measures listed in this Step are appropriate BACT measures for the four process heaters.

BACT selection for Heaters in comparison with other BACT selections at similar sources.

A search of the EPA's RACT/BACT LAER Clearinghouse for gas-fired heaters found two entries which address BACT for GHG emissions from heaters. The first entry is for a pair of 180 MMBtu/hr cracking furnaces at the Williams Olefins, LLC Geismar Ethylene Plant. This entry identifies BACT for GHGs as follows: "1) low-emitting feedstocks, 2) energy efficient equipment, 3) process design improvement, 4) low-emitting and low-carbon fuel (>25 vol% hydrogen, annual avg.)." Although M&G's proposed process heaters are functionally different than Williams' cracking furnaces, M&G's proposed combustion units will feature some of the same BACT for GHGs, including brand new equipment and selection of low-carbon fuel. Although the PET plant will not produce a hydrogen-rich fuel gas, M&G will limit natural gas usage by designing the heaters to fire fuel gas streams generated in the plant (biogas, OCS and EC streams). In addition to these design options, M&G is proposing a numeric energy efficiency-based BACT limit for the heaters. Therefore, the proposed BACT is consistent with this comparison unit. The second BACT entry identified in the RBLCL search is for a 110 MMBtu/hr auxiliary boiler located at the City of Palmdale's Hybrid Power Project. GHG BACT was identified as selection of annual boiler tune ups. M&G is proposing routine heater maintenance as a workpractice BACT requirement in conjunction with energy efficiency design options and the maximum stack temperature. Therefore, the proposed BACT is consistent with this similar unit.

The BACT limitations of the heaters in this permit also compare favorably with similar BACT limitations for heaters in similar service at industrial sites in EPA's recently issued permits in Texas. For example, the Flint Hills Resources, West Refinery permit issued in May 2014 (PSD-TX-6819A-GHG) included hot oil heaters with firing rates comparable to these heaters (123 vs 128 MMBtu/hr heat input), and using natural gas rather than the waste water treatment biogas used here are also limiting exhaust stack gas temperature to below 350°F annually and limiting stack oxygen to below 4% and report an emission factor of 116.2 lb CO₂/MMBtu heat input, compared with the heat input for the heaters in this permit which equal 116.9 lb CO₂/MMBtu heat input on a 12-month rolling basis. Similarly, Enterprise Products Propane Dehydrogenation Unit Reactor Charge Heater HR15.101 was limited to 131.4 lb CO₂/MMBtu on a 12-month rolling basis.

BACT Analysis for Biogas Flare (EPN: FLARE)

As described in the process description sections above, the low pressure flare is used to control the VOC content of the wastewater treatment system biogas when the heaters are unable to accept the gas. The flare does use natural gas as the pilot fuel, and can use natural gas to assure that the minimum BTU content of the waste gas being flared is adequate.

Step 1: Identify All Available Control Technologies

1. Proper flare design and operation. The flare will be designed in accordance with the design requirements of 40 CFR 60.18. The flare will be equipped with monitors to ensure that there is a pilot at all times that waste gas may be directed to the flare and it will also be equipped with a waste gas flow rate monitor. Good flare design will ensure that the design hydrocarbon destruction and removal efficiency (DRE) will be achieved under real world operating conditions. Specifically, the flare tip will be designed to handle maximum design waste gas flow rates and achieve optimal combustion profile at the flare tip (e.g., optimal air and waste gas mixing) to ensure at least 98% destruction (weight percent) of VOCs and 99% destruction of methane.

2. Minimize waste gas flow to the flare. M&G is designing the PET plant with a biogas system which will provide beneficial reuse of biogas in any or all of the heaters. Biogas will be routed to a flare only in case of heater downtime.

Step 2: Eliminate Technically Infeasible Options

Neither control technique is eliminated in this step as they are both technically feasible.

Step 3: Rank Remaining Control Technologies

1. Proper flare design and operation. When flaring, the destruction efficiency will be 99% for methane.
2. Minimize waste gas flow to the flare. This operational and workpractice technique has no efficiency value assignable.

Step 4: Evaluation of control technologies in order of most effective to least effective, with consideration of economic, energy, and environmental impacts and document results

Neither control technique is eliminated in this step as they are both technically feasible. By minimizing biogas routed to the flare by sending the biogas to be used as fuel in the heaters (EPNs: 7A-7D), the total natural gas use is minimized at the site, and energy from the process is conserved.

Step 5: Select BACT

M&G proposes and EPA supports the selection of the available design and operational elements that minimize GHG emissions presented in Step 1 as BACT for the flare.

Since the proposed design and operating elements, described in Step 1 above, are not independent features but are interdependent and represent an integrated energy efficiency strategy, M&G is proposing a BACT limit for the flare which takes into consideration the operation, variability and interaction of all these features in combination. A holistic BACT limit based on the GHG emissions is chosen to account for the ultimate performance of the entire unit.

M&G has proposed that the flare's annual GHG emissions (tpy CO₂e), which includes the emissions associated with the flare pilot and emissions associated with the limited flaring of biogas serve as the numerical BACT limit on a rolling 12-month basis. Flaring of the biogas will occur only when the heaters cannot accept it. The source will also be required to monitor the waste gas flow to the flare to confirm the emissions limitations are not exceeded.

BACT selection for flare in comparison with other BACT selections at similar sources.

A search of the EPA's RACT/BACT/LAER Clearinghouse for flares and found two entries which address BACT for GHG emissions from flares. The first entry is for a marine flare at the Sabine LNG Terminal. This entry lists BACT for GHGs as "proper plant operations and maintain the presence of the flame when the gas is routed to the flare." The second entry is for wet/dry gas flares at the same facility. These units have an entry that identifies GHG BACT that is identical to the marine flare.

There have been no fewer than 17 PSD GHG permits issued or proposed for sources in Texas that include flares, and in each case the BACT for the flares has included good combustion practices, which typically entails compliance with 40 CFR § 60.18 for flares. The flare here is no different. However, some permits also proposed to restrict total emissions by limiting the quantity of material that may be flared or by limiting the number of flaring events authorized (*See* Freeport LNG, PSD-TX-1302-GHG, proposed on December 2, 2013, which restricts operations of the liquefaction flare (EPN PTFFLARE) to no more than 3 MMscf/yr during planned Startup and shutdown events, and the Liquefaction flare (EPN LIQFLARE) 167MMscf/yr during comparable events). In the M&G case, the primary gas that would be routed to the flare is biogas, which is ordinarily a key fuel for the process heaters which will be flared only in the instance when the heaters are unable to make use of the biogas. Therefore, the proposed BACT for M&G's flare (EPN: Flare) is consistent with these similar units.

BACT for Regenerative Thermal Oxidizers 1 and 2 (EPNs: E1 and E2)

As described in the process description section above, the RTOs are designed to destroy VOCs and CO from various waste gas streams. Regenerative thermal oxidizers are, as designed, inherently energy efficient and provide superior energy efficiency compared to a standard (non-regenerative) thermal oxidizer unit as RTOs are specifically designed to minimize the amount of fuel required to maintain the minimum firebox temperature by making use of the energy content of the material being controlled with the device.

Step 1: Identify All Available Control Technologies

1. RTO Selection and Energy Efficient Design and Operation. By selecting an RTO instead of a non-regenerative thermal oxidizer or even a flare, M&G estimates as much as a 90+% reduction in fuel combustion. The RTOs are designed to allow proper combustion temperature using the heating value of the waste gases routed to it without use of additional natural gas. The natural gas burner may be switched off while process gas is injected, provided the process gas has sufficient heat content to maintain the appropriate temperature to assure the required control efficiency is met. This design feature results in the consumption of up to 95+% less natural gas that would be required were the thermal oxidizer be continuously fired. The RTOs will also be designed to minimize the electrical power used to drive the combustion blower by installation of a variable speed blower and corresponding instrumentation and control systems.
2. Low carbon content fuels. Natural gas has the lowest carbon intensity of any available supplemental fuel gas, thus selection of natural gas as the RTO fuel will minimize emissions of GHGs from RTO fuel combustion. Firing of natural gas shall be limited to 18 MMBtu/hr on a 12-month rolling average basis.

Step 2: Eliminate Technically Infeasible Options

Both cited control techniques are technically possible and are in widespread use. No technically infeasible options were eliminated in this step.

Step 3: Rank Remaining Control Technologies

1. RTO Selection and Energy Efficient Design and Operation (99% DE for methane and lighter VOCs, at least 98% for heavier VOCs)
2. Low carbon content fuels and limit firing natural gas to no more than 18MMBtu/hr on a 12-month rolling basis- no percent efficiency value assignable.

Step 4: Evaluation of control technologies in order of most effective to least effective, with consideration of economic, energy, and environmental impacts and document results

Both cited control techniques are technically possible and are in widespread use. No technically infeasible options were eliminated in this step.

Step 5: Select BACT

M&G has proposed to use the heating value of the waste gases being controlled as the ordinary fuel for the RTOs and to use natural gas as the supplemental RTO fuel gas and utilize energy efficient design and operation of the RTO, as described in Step 1 (above), to limit the amount of fuel gas required to maintain the minimum firebox temperature and achieve proper control of VOCs and CO (the primary function of the RTO).

Since the proposed energy efficiency design options, described in Step 1 above, are not independent features but are interdependent and represent an integrated energy efficiency strategy, M&G has proposed a BACT limit for each RTO which takes into consideration the operation, variability and interaction of all these energy efficient features in combination. A holistic BACT limit considers the ultimate performance of the entire unit, rather than individual independent subsystem performance which would be un-necessarily complex because the interdependent nature of operating parameters means that one parameter cannot necessarily be controlled independently without affecting the other operating parameters.

M&G has proposed a numeric energy efficiency-based BACT limit for RTO fuel gas (natural gas) of 18 MMBtu/hr. (per RTO, HHV basis), based on a twelve month rolling average. To demonstrate compliance with this limit, M&G has proposed to use fuel gas flow monitoring in conjunction with natural gas heating values to calculate the twelve month rolling average fuel gas heat input to the RTOs. EPA concurs that this limit is BACT and considers that this 18 MMBtu/hr BACT limit will provide ongoing demonstration that the RTOs achieve the represented energy efficiency by limiting heat input (fuel use) via operation of the natural gas conservation systems.

BACT selection for RTOs in comparison with other BACT selections at similar sources.

A search of the EPA's RACT/BACT/LAER Clearinghouse for RTOs and found no entries which address BACT for GHG emissions for RTOs. In addition, M&G searched pending GHG permit applications and issued GHG permits in other states and EPA regions for any proposed RTOs at chemical plants and found no entries. Although not listed in the RBLC, M&G performed a search of GHG BACT analysis in other GHG permit applications submitted to EPA Region 6 that included an RTO. A discussion of M&G's proposed BACT as compared to those projects is provided below:

- ExxonMobil Chemical-Mont Belvieu Plastics Plant
On May 21, 2012, ExxonMobil Chemical submitted a permit application to EPA Region 6 for construction of a new low-pressure polyethylene unit. Proposed RTO BACT in this

application is to use natural gas as assist gas, good operating and maintenance practices and energy efficient design. This permit application also included a low profile flare as a backup control device during periods of RTO outage. The permit issued on September 5, 2013 required these measures.

M&G is proposing to construct a PET plant, which features different equipment and operating parameters as compared to ExxonMobil's process. M&G is proposing to use two (redundant) RTOs for emission control. In doing so, >99% destruction of VOCs (99.5% for methane and lighter carbon compounds) will be achieved (versus 98% for the flare) at all times. In other words, by selecting redundant RTOs versus a combination of control device types (e.g., RTO and flare), the VOC destruction efficiency will be maximized for the waste streams routed to the RTOs. M&G is also proposing specific energy efficient RTO design options and a holistic numeric energy efficiency-based BACT limit and monitoring methods as BACT for the RTOs.

- **Targa Gas Processing LLC-Longhorn Gas Plant**
On February 17, 2012, Targa submitted a GHG permit application to EPA Region 6 requesting authorization for a new natural gas processing plant. This permit application included one RTO for which applicant proposed the following BACT: use of natural gas as fuel gas, and proper RTO design, operation and maintenance. Targa also proposed a numeric BACT limit for total annual GHG emissions (12-month rolling average and proposed monitoring of fuel gas flow rate to demonstrate compliance. The permit issued on June 17, 2013 required these measures.

M&G is also proposing fuel gas monitoring but is additionally proposing an energy efficiency-based operational BACT limit (18 MMBtu/hr, per RTO) which limits the fuel gas fired in the RTOs. In addition, by selecting redundant RTOs (two RTOs), the control device on-stream time and thus the overall VOC destruction efficiency will be maximized for the waste gas streams routed to the RTOs.

BACT for Natural Gas and Biogas Piping Fugitives

The proposed project will include natural gas piping components. These components are potential sources of methane and CO₂ emissions due to emissions from rotary shaft seals, connection interfaces, valve stems, and similar points. Emissions can occur when a fuel system or pipe run must be de-inventoried in association with any operational reason, including for safety purposes.

Step 1: Identification of Potential Control Technologies for GHGs

1. Use of leakless piping components such as bellows valves. Leakless valves are primarily used where highly toxic or otherwise hazardous materials are present.
2. Implementation of leak detection and repair (LDAR) program using a hand held analyzer.
3. Implementation of alternative monitoring using a remote sensing technology such as infrared cameras
4. Implementation of audio/visual/olfactory (AVO) leak detection program.

5. Minimization of pipeline de-inventorying to atmosphere. When equipment must be de-inventoried of GHG containing gasses, in order to safely perform necessary plant operations related to startup, shutdown, maintenance, or repair operations, and it is impossible that the vented emissions be controlled by the ordinary control device, the vented stream volume must be minimize, to the extent practicable and necessary to safely perform the necessary operations of the plant.

Step 2: Eliminate Technically Infeasible Options

All options identified in Step 1 are considered technically feasible for this project.

Step 3: Ranking of Remaining Technologies Based on Effectiveness.

1. Use of leakless piping components such as bellows valves. Leakless valves have the best control effectiveness compared to standard components.
2. Implementation of leak detection and repair (LDAR) program using a hand held analyzer. The use of a LDAR program with a portable gas analyzer meeting the requirements of 40 CFR 60, Appendix A, Method 21, can be effective for identifying leaking methane. Quarterly instrument monitoring with a leak definition of 10,000 part per million by volume (ppmv) (TCEQ 28M LDAR Program) is generally assigned a control efficiency of 75% for valves, relief valves, sampling connections, and compressors and 30% for flanges. Quarterly instrument monitoring with a leak definition of 500 ppmv (TCEQ 28VHP LDAR Program) is generally assigned a control efficiency of 97% for valves, relief valves, and sampling connections, 85% for compressors, and 30% for flanges
3. Implementation of alternative monitoring using a remote sensing technology such as infrared cameras. The U.S. EPA has allowed the use of an optical gas imaging instrument as an alternative work practice for a Method 21 portable analyzer for monitoring equipment for leaks in 40 CFR 60.18(g).
4. Implementation of audio/visual/olfactory (AVO) leak detection program. For components containing inorganic or odorous compounds, periodic AVO walk-through inspections provide predicted control efficiencies of 97% control for valves, flanges, relief valves, and sampling connections, and 95% for compressors.¹⁶
5. Minimization of pipeline de-inventorying to atmosphere. There is no firm control efficiency value assigned to this workpractice standard.

¹⁶ Control Efficiencies for TCEQ Leak Detection and Repair Programs available at http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/control_eff.pdf (last accessed July 23, 2014)

Step 4: Evaluation of control technologies in order of most effective to least effective, with consideration of economic, energy, and environmental impacts

1. Use of leakless piping components. Leakless valves are expensive in comparison to a standard (non-leakless) valve. These technologies are generally considered cost prohibitive except for specialized service.
- 2-4 LDAR programs are typically implemented for control of VOC emissions from materials in VOC service (at least 5 wt.% VOC or HAP). All of the instrumental and AVO equipment leak techniques are well established control technology, and so remain viable candidates for BACT. The primary difference between the instrumented LDAR programs and the AVO LDAR program is the leak definition. In the case of odiferous compounds, such as odorized natural gas, AVO programs are as effective at detecting leaking components as instrumental programs and are simpler to implement.
5. With regard to the necessity of de-inventorying components or fuel systems in GHG service to assure the ongoing proper and safe operation of the source, minimization of the volume of the gasses so de-inventoried to atmosphere is the only practical workpractice standard that can be implemented to minimize the GHG from these events.

Step 5: Selection of BACT

Due to the very low volatile organic compound (VOC) content of natural gas, the source will not be subject to any VOC leak detection programs by way of its State/PSD air permit, TCEQ Chapter 115 – Control of Air Pollution from Volatile Organic Compounds, New Source Performance Standards (40 CFR Part 60), National Emission Standard for Hazardous Air Pollutants (40 CFR Part 61); or National Emission Standard for Hazardous Air Pollutants for Source Categories (40 CFR Part 63). Therefore, any leak detection program implemented will be solely due to potential greenhouse emissions for the equipment within the PET Plant. Since the uncontrolled CO_{2e} emissions from the natural gas piping represent less than 0.01% of the total sitewide CO_{2e} emissions, any emission control techniques applied to the piping fugitives will provide minimal sitewide CO_{2e} emission reductions. Because the compound of interest, coming from piping equipment in odorized natural gas service, is an odiferous compound, a properly implemented AVO program will be as effective as an instrumented program at identifying leaking components for repair, and at much less cost. Consequently, an AVO program is BACT for this source.

Based on this top-down analysis, M&G Resins will conduct weekly AVO inspections as BACT for piping components in natural gas service. Likewise, the minimization of the volume of gasses de-inventoried or vented to atmosphere from fuel systems or piping and equipment components in GHG service is BACT for such events, where such emissions cannot be routed through their ordinary control device, if any, due to safety concerns.

BACT selection for Fugitives in comparison with other BACT selections at similar sources.

In addition to the RBLC search, M&G performed, the EPA reviewed BACT analyses in other GHG permitting records at EPA Region 6. A discussion of the proposed BACT as compared to those projects is provided below:

- Equistar Channelview-Olefins I & II Expansions PSD-TX-1272-GHG, issued 7/19/2013. For GHG fugitive emissions, Equistar is required to conduct instrumental monitoring of components (TCEQ LDAR program 28LAER and the use of good quality components. This source is located in a severe ozone non-attainment area.
- Equistar La Porte-Olefins Expansion PSD-TX-752-GHG, issued 3/14/2013. In this application Equistar proposes to employ TCEQ's 28 LAER fugitive leak detection and repair program for components "in CH₄ service" as BACT. This facility is located in a severe ozone non-attainment area.
- Flint Hills Resources, West Refinery, PSD-TX-6819A-GHG, issued on 5/23/2014. Flint Hills is implementing TCEQ's 28 VHP program, as well as a visual, olfactory, and auditory program of leak detection and timely repair of components found to be leaking.

The proposed weekly AVO monitoring matches the Flint Hills Resources BACT for fugitives by requiring an AVO program. The two sources located in the severe ozone nonattainment areas are already implementing a more stringent equipment monitoring program due to ozone nonattainment concerns that are not applicable in Corpus Christi. The Flint Hills facility implements some aspects of their fugitive monitoring program as the result of a court settlement, and so have an independent reason to have instrumental monitoring. As described in the discussion, an AVO program, when implemented on odiferous compounds, such as pipeline quality natural gas that has been odorized, an AVO program can be as effective as instrumented methods in cost effectively and timely finding leaking components. Therefore, the AVO program proposed here is comparable to the BACT required of other similar sources in Texas.

BACT for Emergency Diesel Generators 1 and 2 (EPNs: E85-A, E85-B) and Fire Water Pump Diesel Engines 1 and 2 (EPNs: E87-A, E87-B)

The emergency generator engines and the emergency firewater pump engines combust diesel fuel and are sources of GHG emissions. Diesel fuel rather than a lower carbon fuel is required due to the emergency use only nature of the engines. They must be operable independently of any natural gas supply to the site. The emergency engines will be operate at a low capacity factor during non-emergency operating hours to testing, readiness checks, and up to 50 hours of other non-emergency operations (no more than 100 hrs/yr, total per emissions unit) as they are subject to 40 CFR Part 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ. As such, the engines will be required to meet specific emission standards based on engine size, model year, and end use, the engines will be required to meet certain maintenance requirements, and will be fitted with a non-resettable hour meter, all in accordance with the requirements of the two sets of applicable requirements.

Step 1: Identification of Potential Control Technologies for GHGs

1. Good Operation and Maintenance Practices – Good operation and maintenance practices for compression ignition engines include appropriate maintenance of equipment, periodic testing conducted weekly, and operating within the recommended air to fuel ratio, as specified by its design. A search of the RBLC database did not identify any add-on GHG

control technologies for emergency generator diesel engines. Low capacity utilization under non-emergency conditions (up to 100 hrs/yr) coupled with operating in compliance with the applicable requirements of 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ will assure proper operation and maintenance for engines in emergency use.

Step 2: Elimination of Technically Infeasible Alternatives

The option identified in Step 1 is considered technically feasible for this project.

Step 3: Ranking of Remaining Technologies Based on Effectiveness.

The option identified in Step 1 is considered the best method of emissions limitations for this source type.

Step 4: Evaluation of control technologies in order of most effective to least effective, with consideration of economic, energy, and environmental impacts

M&G is proposing to implement the control option as listed in Step 1. Detailed cost analysis is not necessary. No adverse collateral impacts are expected.

Step 5: Selection

Total GHG emissions from the emergency engines shall be limited to 2,585 tons CO₂e/year for non-emergency operations from each generator engine, and 285 tons CO₂e/year for non-emergency operations from each firewater engine. M&G shall employ good combustion practices, including tune-ups and manufacturer's recommended inspections and maintenance. The engines selected will meet the requirements of 40 CFR Part 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ.

To calculate the CO₂e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1 as published on November 29, 2013 (78 FR 71904). Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month rolling average. Additionally, M&G shall maintain records of fuel usage, hours of operation, and maintenance/tune-ups performed on the engine.

EPA finds that the proposed controls and work-practices are BACT for the emergency engines.

IX. Endangered Species Act

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) submitted on March 4, 2014, prepared by the applicant, M&G Resins USA, LLC ("M&G"), and its consultant, Zephyr Environmental Corporation, Inc. ("Zephyr"), thoroughly reviewed and adopted by EPA. M&G is proposing to construct a new plastic resin manufacturing plant at its site located in Corpus Christi, Nueces County, Texas. The facility will consist of a PET Plant (a polyethylene terephthalate (PET) unit and a terephthalic acid (PTA) unit), and a new heat and/or heat and power utility plant (Utility Plant) both owned and operated by M&G. The PET Plant and the Utility Plant will receive a separate Greenhouse Gas Permit (GHG) permit, but for the purpose of Section 7 of the Endangered Species Act, EPA is relying on a Biological Assessment that includes the collective emissions from both projects and their impacts to endangered species. The biological assessment performed for M&G included in its field survey the physical land area where the new facilities will be built.

A draft BA has identified seventeen (17) species listed as federally endangered or threatened in Nueces County, Texas:

Federally Listed Species for Nueces County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS), and the Texas Parks and Wildlife Department (TPWD)	Scientific Name
Reptiles	
Green sea turtle	<i>Chelonia mydas</i>
Hawksbill sea turtle	<i>Eretmochelys imbricata</i>
Kemp's ridley sea turtle	<i>Lepidochelys kempii</i>
Leatherback sea turtle	<i>Dermochelys coriacea</i>
Loggerhead sea turtle	<i>Caretta caretta</i>
Birds	
Piping plover	<i>Charadrius melodus</i>
Northern Aplomado falcon	<i>Falco femoralis septentrionalis</i>
Whooping crane	<i>Grus americanus</i>
Red knot	<i>Calidris canutus rufa</i>
Eskimo curlew	<i>Numenius borealis</i>
Fish	
Smalltooth sawfish	<i>Pristis pectinata</i>
Mammals	

Federally Listed Species for Nueces County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS), and the Texas Parks and Wildlife Department (TPWD)	Scientific Name
Gulf coast jagaurundi	<i>Herpailuraus yagouaroundsi cacomitli</i>
Ocelot	<i>Leopardus pardalis</i>
West Indian manatee	<i>Trichechus manatus</i>
Red wolf	<i>Canis rufus</i>
Plants	
Slender rush-pea	<i>Hoggmannseggia tenella</i>
South Texas ambrosia	<i>Ambrosia cheiranthifolia</i>

EPA has determined that issuance of the proposed permits to M&G for the new PET plant and Utility Plant will have no effect on ten (10) of these listed species, specifically the red wolf (*Canis rufus*), ocelot (*Leopardus pardalis*), Gulf coast jagaurundi (*Herpailuraus yagouaroundsi cacomitli*), slender rush-pea (*Hoffmannseggia tenella*), piping plover (*Charadrius melodus*), Northern Aplomado falcon (*Falco femoralis septentrionalis*), red knot (*Calidris canutus rufa*), eskimo curlew (*Numenius borealis*), South Texas ambrosia (*Ambrosia cheiranthifolia*), and smalltooth sawfish (*Pristis pectinata*). These species are either thought to be extirpated from the county or Texas or not present in the action area.

Two terrestrial (2) species, whooping crane (*Grus americana*) and West Indian manatee (*Trichechus manatus*), identified are species that may be present in the Action Area. As a result of this potential occurrence and based on the information provided in the draft BA, the issuance of the permit may affect, but is not likely to adversely affect the whooping crane and the West Indian manatee.

EPA has determined that these federally-listed endangered marine species can potentially found within the action area of the project.

- leatherback sea turtle (*Dermochelys coriacea*)
- green sea turtle (*Chelonia mydas*)
- Kemp's ridley sea turtle (*Lepidochelys kempii*)
- loggerhead sea turtle (*Caretta caretta*)
- Hawksbill sea turtle (*Eretmochelys imbricate*)

As a result of this potential occurrence and based on the information provided in the draft BA, the issuance of the permit may affect but is not likely to adversely affect the leatherback sea turtle, green sea turtle, Kemp's ridley sea turtle, loggerhead sea turtle, and hawksbill sea turtle.

On April 4 2014, EPA submitted the final draft BA, dated March 5, 2014, to the Southwest Region, Corpus Christi, Texas Ecological Services Field Office of the USFWS for its concurrence that issuance of the permit may affect, but is not likely to adversely affect the whooping crane, West Indian manatee, leatherback sea turtle, green sea turtle, Kemp's ridley sea

turtle, loggerhead sea turtle, and hawksbill sea turtle. USFWS provided concurrence and agreed with EPA's determinations on April 23, 2014.

EPA submitted the final draft BA, dated March 5, 2014, to the NOAA Southeast Regional Office, Protected Resources Division of NMFS on March 31, 2014, for its concurrence that issuance of the permit may affect, but is not likely to adversely affect the leatherback sea turtle, green sea turtle, Kemp's ridley sea turtle, loggerhead sea turtle, and hawksbill sea turtle. NOAA provided concurrence and agreed with EPA's determinations on June 3, 2014.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at <http://yosemite.epa.gov/r6/Apermit.nsf/AirP>.

X. Magnuson-Stevens Act

The 1996 Essential Fish Habitat (EFH) amendments to the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act) set forth a mandate for the National Oceanic Atmospheric Administration's National Marine Fisheries Service (NMFS), regional fishery management councils, and other federal agencies to identify and protect important marine and anadromous fish habitat.

To meet the requirements of the Magnuson-Stevens Act, EPA is relying on an EFH assessment prepared by Zephyr on behalf of M&G, submitted on July 9, 2013, and reviewed and adopted by EPA. The EFH assessment looks at the total emissions and impacts from both GHG projects on marine and fish habitats.

The facility affects tidally influenced portions of the Nueces River, which adjoins to Nueces Bay and feeds into Corpus Christi Bay leading to the Gulf of Mexico, and Viola Ship Channel, which adjoins to the Corpus Christi Bay leading to the Gulf of Mexico. These tidally influenced portions have been identified as potential habitats of postlarval, juvenile, subadult or adult stages of red drum (*Sciaenops ocellatus*), shrimp (4 species), and reef fish (43 species) and the stone crab (*Menippe mercenaria*). The EFH information was obtained from the NMFS's website (<http://www.habitat.noaa.gov/protection/efh/efhmapper/index.html>).

Based on the information provided in the EFH Assessment, EPA concludes that the proposed PSD permits allowing for the construction of the M&G PET Plant and Utility Plant will have no adverse impacts on listed marine and fish habitats. The assessment's analysis, which is consistent with the analysis used in the BA discussed above, shows the projects' construction and operation will have no adverse effect on EFH.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final essential fish habitat report can be found at EPA's Region 6 Air Permits website at: <http://yosemite.epa.gov/r6/Apermit.nsf/AirP>.

XII. National Historic Preservation Act

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on and adopted a cultural resource report prepared by Horizon Environmental Services, Inc. (Horizon) on behalf of Zephyr, for M&G facilities, submitted in March 10, 2014.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be location of the M&G PET facility and Utility Plant. Horizon conducted a field survey, including shovel testing and backhoe trenching, of the APE and a desktop review within a 1.0-mile radius of the APE. The desktop review included an archaeological background and historical records review using the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP). Based on the desktop review, eight archaeological sites potentially eligible for listing on the National Register were identified within 1.0-mile of the APE; however all eight sites were located outside the APE.

EPA Region 6 determines that since there are no historic properties or archaeological resources located within the APE, issuance of the permits to M&G will not affect properties potentially eligible for listing on the National Register.

On March 6, 2014, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. On August 13, 2014, EPA provided a copy of the report to Texas's State Historic Preservation Officer (SHPO) for consultation and concurrence with its determination. SHPO provided concurrence and agreed with EPA's determinations on August 21, 2014.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at <http://yosemite.epa.gov/r6/Apermit.nsf/AirP>.

XIII. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1,123 (EAB 2006); *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS)

for GHG. The global climate-change inducing effects of GHG emissions, according to the “Endangerment and Cause or Contribute Finding”, are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGs at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XIV. Conclusion and Proposed Action

Based on the information supplied by M&G, our review of the analyses contained in the TCEQ NSR Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue M&G a PSD permit for GHGs for the PET Plant, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

Table 1 M&G PET Plant Annual Emissions and BACT Summary

FIN	EPN	Description	GHG Mass Basis		TPY ^{1,2,3} CO ₂ e	BACT Requirements
			GHG	TPY		
E7-A ⁴	E7-A	HTF Heater	CO ₂	72,622	72,622	Limit the heat CO ₂ heat input factor to 116.9 lb CO ₂ /MMBtu and the exhaust gas temperature maximum average to 320°F, both 12-month rolling averages.. See permit condition III.A.6
			CH ₄	1.37	34.25	
			N ₂ O	0.14	41.72	
E7-B ⁴	E7-B	HTF Heater	CO ₂	72,622	72,622	
			CH ₄	1.37	34.25	
			N ₂ O	0.14	41.72	
E7-C ⁴	E7-C	HTF Heater	CO ₂	72,622	72,622	
			CH ₄	1.37	34.25	
			N ₂ O	0.14	41.72	
E7-D ⁴	E7-D	HTF Heater	CO ₂	72,622	72,622	
			CH ₄	1.37	34.25	
			N ₂ O	0.14	41.72	
E1 ⁵	E1	RTO 1	CO ₂	54,495	54,495	Maintain a minimum combustion temperature as determined by initial compliance testing and limit natural gas firing to no more than 18MMBtu/hr on a rolling 12-month basis. See permit condition III.C.
			CH ₄	83	2,075	
			N ₂ O	0.54	160.92	
E2 ⁵	E2	RTO 2	CO ₂	54,495	54,495	
			CH ₄	83	2,075	
			N ₂ O	0.54	160.92	
FLARE ⁶	FLARE	Biogas Flare-Flaring nat gas pilot only	CO ₂	8,942	8,942	Good combustion and maintenance practices. See permit condition III.B
			CH ₄	13	340	
			N ₂ O	0.1	26.6	
E85-A	E85-A	Emergency Diesel Generator	CO ₂	2,577	2,577	Low annual capacity factor and annual routine maintenance as prescribed by NSPS and MACT. See permit condition III.D.
			CH ₄	0.1	2.5	
			N ₂ O	0.02	5.96	
E85-B	E85-B	Emergency Diesel Generator	CO ₂	2,577	2,577	Low annual capacity factor and annual routine maintenance as prescribed by NSPS and MACT. See permit condition III.D.
			CH ₄	0.1	2.5	
			N ₂ O	0.02	5.96	
E87-A	E87-A	Fire Water Pump Diesel Generator	CO ₂	248	248	Low annual capacity factor and annual routine maintenance as prescribed by NSPS and MACT. See permit condition III.E.
			CH ₄	0.01	0.25	
			N ₂ O	0.002	0.596	
E87-B	E87-B	Fire Water Pump Diesel Generator	CO ₂	248	248	Low annual capacity factor and annual routine maintenance as prescribed by NSPS and MACT. See permit condition III.E.
			CH ₄	0.01	0.25	
			N ₂ O	0.002	0.596	
FUGPTA ⁷	FUGPTA	Combined Plant Fugitives	CO ₂	--	--	Implementation of LDAR/AVO program. See permit condition III.F.
FUGPET ⁷	FUGPET		CH ₄	--	--	
Totals			CO ₂	432,946	432,946	
			CH ₄	193	4,825	
			N ₂ O	2	396	
			CO ₂ e	--	438,273	

Table 1. Annual Emission Limits notes

1. Compliance with the annual emission limits (tons per year) is based on a 12-month, rolling total and are not to be exceeded for any emissions unit.
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): $\text{CO}_2=1$, $\text{CH}_4 = 25$, $\text{N}_2\text{O} = 298$
4. Includes the products of combustion of firing biogas and waste gas either as fuel or as part of the combustion air fed to the heaters. The maximum amount of waste gas to be fired will result in emissions of the following GHG: 9,581 tpy CO_2 , 0.21 tpy CH_4 and 0.02 tpy N_2O .
5. Includes the products of combustion of firing natural gas as supplemental fuel. The maximum amount of natural gas to be fired will result in emissions of the following GHG: 9,103 tpy CO_2 , 0.17 tpy CH_4 and 0.02 tpy N_2O .
6. Includes the products of combustion of firing natural gas as a pilot and firing methane rich biogas, when biogas cannot be routed to the HTF heaters. The natural gas for the pilot results in the following products of combustion: GHG: 31tpy CO_2 , 0.01 tpy CH_4 and 0.02 tpy N_2O . Note that if biogas is routed to the flare, it will not be routed to the HTF Heaters. Monitoring will be used to assure compliance.
7. Fugitive process emissions limitations from EPNs FUG-PTA and FUG-PET are estimates only, compliance with which is determined by the proper implementation of the AVO workpractice standard. Estimates include approximately 0.72 tpy CO_2 and 20.27 tpy CH_4 , which equals approximately 507.47 tpy CO_2e for each fugitive source, or 1014.94 tpy CO_2e combined.