Toups, Brad

From: Thomas Sullivan <tsullivan@zephyrenv.com>
Sent: Friday, September 26, 2014 5:08 PM
To: Toups, Brad
Cc: Larry Moon
Subject: RE: M&G draft permit and statement of basis for the PET plant ready for your review

Sorry Brad,

I had the response drafted two days ago and apparently was pulled away before I hit send.

1. In response to your question regarding the energy recovery system generators in the PTA Unit. The electricity produced is sufficient to meet approximately 50% (+or – 5%) of the total plant electricity demand under 100% operating conditions.

2. As we discussed M&G does prefer that both the Utility and PET Plant Permits go to public notice concurrently.

Best Regards,
Thomas

From: Toups, Brad [mailto:Toups.Brad@epa.gov]
Sent: Friday, September 26, 2014 5:01 PM
To: Thomas Sullivan
Subject: RE: M&G draft permit and statement of basis for the PET plant ready for your review

Thomas, following up on our email exchange of earlier this week on M&G:

1) Will you be providing some info on the electrical generation using the steam turbine, as inferred on Page 16 of the original application? What percent, or range, of plant energy is this use intended to provide?
2) Did you confirm that we should go to notice on both projects at the same time?

Thanks,
Brad

From: Thomas Sullivan [mailto:tsullivan@zephyrenv.com]
Sent: Friday, September 26, 2014 4:44 PM
To: Toups, Brad; Larry Moon
Cc: mauro.fenoglio@gruppomg.com; Allana.ratliff@chemtex.com; Flavio Assis (Flavio.Assis@gruppomg.com.br); Martha.Martinez@gruppomgus.com; Ken.Jude@gruppomgus.com; Brett Davis
Subject: RE: M&G draft permit and statement of basis for the PET plant ready for your review

Brad,

Attached are copies of the PET plant draft permit and SOB with our comments in track changes form. Note that the SOB comments on the Table 1a footnotes are applicable to the Utility Plant SOB as well (I did not include a mark of the Utility SOB). Thank you for your time and effort on these permits, and let us know if you have any further questions or concerns.

Best Regards,
Thomas

Thomas Sullivan P.E. | Principal
Zephyr Environmental Corporation
2600 Via Fortuna, Ste 450 | Austin, TX 78746
Direct: 512.879.6632 | Cell: 512.650.7613 | tsullivan@zephyrenv.com
ZephyrEnv.com | HazMatAcademy.com

From: Toups, Brad [mailto:Toups.Brad@epa.gov]
Sent: Thursday, September 25, 2014 2:48 AM
To: Larry Moon; Thomas Sullivan
Subject: M&G draft permit and statement of basis for the PET plant ready for your review

Hi Larry, Thomas,

I have attached a copy of the draft permit and SOB for the PET plant. For your reference, I have also attached a revised copy of the Utility Plant SOB because I have harmonized the BACT discussion between the PET Plant and the Utility Plant.

We are now on target for obtaining Wren's approval by 9/30 (next Tuesday) to proceed to public Notice publishing such notice on October 8. The PN period will then run from October 8 thru Nov 7. We have a tentative schedule for a Hearing, if requested, to be held either on November 18 or 19, and that date should be firmed up by Friday.

Please provide your comments, if at all possible, by Friday COB so that I can get the package to Wren for her approval shortly thereafter.

Thanks

Brad Toups
Air Permit Section
Multimedia Planning and Permitting Division
US EPA, Region 6
1445 Ross Ave, Suite 1200 (6PD-R)
Dallas, Tx 75202
214.665.7258

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

September 23, 2014

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

[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."

of emission units), this SOB otherwise conducts a BACT review only for the emissions attributable 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: 27º 50’ 7.8899” North
Longitude: - 97º 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:

Table 1. Sitewide GHG Emissions Summary (tpy)

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
CO_2	432,946	738,926	1,171,872	432,946	622,555	1,055,501
CH_4	193	34	227	193	32	225
N_2O	2	1	3	2	1	3
CO_2e	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. CO_2e 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 CO_2=1, CH_4=25, and N_2O=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, Tables 1a, below, show 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_2e	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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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_2e**				
			CH_4	**193**	**438,273**				
			N_2O	**2**					

Notes:

1 Waste gas 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 waste gas which offsets heater natural gas use.

2 Waste gas may be routed to the flare, but if so, won't be routed to any heater. Monitoring provisions assure compliance.

3 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 biogas (predominately methane) being treated by the RTO, therefore the emissions attributable to waste gas include the natural gas supplementally fired.

4 Natural Gas can and will be fired concurrently with waste gas in the RTO to maintain proper operating conditions.

Commented [CB1]: Footnotes should read as follows, Please add to Utility Plant SOB as well:

1. 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.
2. 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.
3. 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.

Table 1b M&G Project Jumbo GHG Emissions- Utility Plant

Utility Plant: Option 1

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e	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_2O	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_2O	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_2O	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_2O						
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_2O						
Totals			**CO_2**	**738,926**	**CO_2e**				
			CH_4	**34.3**	**740,201**	**62.8% of sitewide emissions**			
			N_2O	**1.4**					

Table 1c M&G Project Jumbo GHG Emissions- Utility Plant

Utility Plant: Option 2

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e	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_2O	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_2O	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_2O	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_2O						
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_2O						
Totals			**CO_2**	**622,555**	**CO_2e**				
			CH_4	**32.1**	**623,709**	**58.7% of sitewide emissions**			
			N_2O	**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 application[2] 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
- 5 tanks for p-xylene
- 1 DEG tank
- 1 acetic acid tank
- 1 caustic storage tank

Commented [TS2]: Note that an aqueous ammonia tank was added as part of the SCR system on the HTF 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 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 DEG, Acetic Acid and 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).
- EG 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 (CO_2)). 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 %), CO_2 (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 CO_2 (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. CO_2e emissions from the RTOs comprise approximately 10-12% of the CO_2e 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. 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 do 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 Blow down 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 (electric motors) for the PTA unit.

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: El, 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 CO_2 concentration exhaust stream (approximately 2%) accounts for about 10% of the CO_2 emissions from the site.

Deleted: The RTOs are designed for redundant operation where waste gas can be routed to either, or both RTOs.

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 (CH_4) and carbon dioxide (CO_2).

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 Utiltity 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 (CO_2) at a volumetric flow rate of from 2 (heaters and RTOs) to approximately 8% (boilers), and small amounts of nitrous oxide (N_2O) and methane (CH_4). Carbon dioxide accounts for approximately 99.5% of the CO_2e emissions at the entire site (all but approximately 6,600 tpy CO_2e of the worst case sitewide total of 1,178,441 tpy CO_2e), therefore this BACT analysis addresses primarily CO_2 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 MMbut/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 CO_2 emissions from the PET plant and 28% of the site-wide CO_2 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 CO_2 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, CO_2 emissions contribute the most volume (greater than 99%) to the overall emissions; therefore, additional analysis is not required for CH_4 and N_2O.

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 CO_2 in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 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 CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 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 CO_2 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 CO_2 from oxygen-containing streams with low CO_2 concentrations typical of gas turbine exhaust.[6]

M&G cites to Alstom, one of the major developers of commercial CO_2 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 CO_2 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 site[7] that its CO_2 capture technology will become commercially available in 2015. However, the company does not indicate whether such technology will be available for capture of CO_2 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 CO_2 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% CO_2 by volume range. These post combustion emissions streams may contain other products of combustion such as PM, NO_x and SO_2, thus increasing the challenge of CO_2 separation for the project.

M&G indicates, and the EPA recognizes, that although amine absorption technology for CO_2 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 plants[8].

CCS: Compression and Transport. Once separated from the flue gas stream, the CO_2 will need to be transported to its ultimate storage location. Unless the final storage location is nearby, the efficient transportation of a CO_2 stream will require that the stream be compressed to the supercritical fluid state for transportation in high pressure pipeline[9]. 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]

[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 CO_2 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

CCS: Storage. Specific types of geologic formations capable of receiving and permanently storing CO_2 are the target long term storage reservoirs for CO_2 streams. CO_2 floods have been used in enhanced oil recovery (EOR) operations for decades. Essentially EOR operations inject CO_2 under pressure through multiple injection wells in an existing suitable oil field producing zone. When injected, the CO_2 aids in the flow of of oil to producing oil wells that are located on the other end of the oil field area. CO_2 recovered with the produced oil is then recirculated back to the injection wells for reinjection. Such geologic formations have characteristics that allow the CO_2 to remain in the oil field producing zone for extended periods of time, and perhaps permanently. 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 CO_2 storage, the W.A. Parish Post Combustion CO_2 Capture and Sequestration Project, funded partially by the Department of Energy, is proposing to use CO_2 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, TX[12].

Other locations are currently being studied as potentially long term sequestration sites for anthropomorphic CO_2. The US. Department of Energy has identified the Stacked Storage location in the Cranfield Field Site in Mississippi as one such location[13]. In comparison, the closest site that is currently being field-tested to demonstrate its capacity for large-scale geological storage of CO_2 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

[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 CO_2 Capture and Sequestration Project Draft Evironmental 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

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.

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 CO_2 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 CO_2 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].

[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

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 CO_2e/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 CO_2 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 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 CO_2 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 CO_2 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 CO_2, and the RTOs having a CO_2 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 CO_2 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, and in light of the additional environmental air quality impacts incident to the generation of the additional energy required to implement CCS, 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. EPA has determined that these are appropriate BACT measures.

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 RBLC 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 CO_2/MMBtu heat input, compared with the heat input for the heaters in this permit which equal 116.9 lb CO_2/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 CO_2/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 CO_2e), 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

boilers 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 Liquifaction 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.

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 (99.5% DE for methane and lighter VOCs, at least 98% for heavier VOCs)
2. Low carbon content fuels- 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

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 CO_2 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: Elimination of Technically Infeasible Alternatives
Step 2: Elimination of Technically Infeasible Alternatives

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.

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 site wide 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, 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.

[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)

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 RTOs 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 CH_4 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 Engines

The proposed project will include installation of a new, high efficiency emergency generators and firewater pumps. Use of these engines for purpose of maintenance checks and readiness testing will be limited to 100 hours per year each per the applicable New Source Performance Standard for Stationary Compression Ignition Internal Combustion Engines.

As such, the engines will be required to meet specific emission standards based on engine size, model year, and end use. The use of engines with a low annual capacity factor and performance of annual routine maintenance (as prescribed by the NSPS) is BACT for GHG emissions for engines, and has been prescribed and identified as such for all firewater pump engines and emergency electric generation engines authorized in PSD GHG permits issued to date in Texas.

EPA concurs that this is 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 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	*Chelonia mydas*
Hawksbill sea turtle	*Eretmochelys imbriacata*
Kemp's ridley sea turtle	*Lepidochelys kempii*
Leatherback sea turtle	*Dermochelys coriaea*
Loggerhead sea turtle	*Caretta caretta*
Birds	
Piper plover	*Charadrius melodus*
Northern aplomado falcon	*Falco femoralis septentrionalis*
Whooping crane	*Grus americanus*
Red knot	*Calidris canutus rufa*
Eskimo curlew	*Numenius borealis*
Fish	

Smalltooth sawfish	*Pristis pectinata*
Mammals	
Gulf coast jagaurundi	*Herpailuraus yagouaroundi cacomitli*
Ocelot	*Leopardus pardalis*
West Indian manatee	*Trichechus manatus*
Red wolf	*Canis rufus*
Plants	
Slender rush-pea	*Hoggmannseggia tenella*
South Texas ambrosia	*Ambrosia cheiranthifolia*

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 the red wolf (*Canis rufus*), slender rush-pea (*Hoffmannseggia tenella*), interior least tern (*Sternula antillarum athalassos*), eskimo curlew (*Numenius borealis*), South Texas ambrosia (*Ambrosia cheiranthifolia*), Black lace cactus (*Echinocereus reichenbachii var. albertii*), and. 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.

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 those two federally-listed species. USFWS provided concurrence and agreed with EPA's determinations on April 23, 2014.

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, 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 these federally-listed species. 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 is 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 facility 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.

XI. 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.

XII. 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.

XIII. 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_2e	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_2O	0.14	41.72	
E7-B[4]	E7-B	HTF Heater	CO_2	72,622	72,622	
			CH_4	1.37	34.25	
			N_2O	0.14	41.72	
E7-C[4]	E7-C	HTF Heater	CO_2	72,622	72,622	
			CH_4	1.37	34.25	
			N_2O	0.14	41.72	
E7-D[4]	E7-D	HTF Heater	CO_2	72,622	72,622	
			CH_4	1.37	34.25	
			N_2O	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. See permit condition III.C.
			CH_4	83	2,075	
			N_2O	0.54	160.92	
E2[5]	E2	RTO 2	CO_2	54,495	54,495	
			CH_4	83	2,075	
			N_2O	0.54	160.92	
FLARE[6]	FLARE	Biogas Flare-Flaring including nat gas pilot	CO_2	8,942	8,942	Good combustion and maintenance practices. See permit condition III.B
			CH_4	13.60	340.00	
			N_2O	0.09	26.52	
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.
			CH_4	0.1	2.5	
			N_2O	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. See permit condition III.D.
			CH_4	0.1	2.5	
			N_2O	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.
			CH_4	0.01	0.25	
			N_2O	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. See permit condition III.E.
			CH_4	0.01	0.25	
			N_2O	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**	**414,101**	**CO_2e**	
			CH_4	**185**	**419,262**	
			N_2O	**2**		

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): CO_2=1, CH_4 = 25, N_2O = 298
4. Includes the products of combustion of firing 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 methane rich biogas from the waste water treatment plant as normal fuel or 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 CH4 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 RTOs. 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 RTOs. 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.

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
FOR GREENHOUSE GAS EMISSIONS
ISSUED PURSUANT TO THE REQUIREMENTS AT 40 CFR § 52.21

U.S. ENVIRONMENTAL PROTECTION AGENCY, REGION 6

PSD PERMIT NUMBER: PSD-TX-1352-GHG

PERMITTEE: M & G Resins USA, L.L.C.
450 Gears Rd Ste 240
Houston, Texas 77067-4513

FACILITY NAME: PET Plant

FACILITY LOCATION: 7001 Joe Fulton Intl Trade Corridor, Suite 100
Corpus Christi, TX 78409

Pursuant to the provisions of the Clean Air Act (CAA), Subchapter I, Part C (42 U.S.C. Section 7470, et. Seq.), and the Code of Federal Regulations (CFR) Title 40, Section 52.21, and the Federal Implementation Plan at 40 CFR § 52.2305 (effective May 1, 2011 and published at 76 FR 25178), the U.S. Environmental Protection Agency, Region 6 is issuing a Prevention of Significant Deterioration (PSD) permit to M & G Resins USA, L.L.C. (M&G Resins) for Greenhouse Gas (GHG) emissions. The Permit for the PET Plant applies to the construction of a plant consisting of a polyethylene terephthalate plant (PET Plant) consisting of a terephthalic acid (PTA) unit, PET unit, and associated equipment in Nueces County, Texas.

M&G Resins is authorized to construct a new PET Plant as described herein, in accordance with the permit application (and plans submitted with the permit application), the federal PSD regulations at 40 CFR § 52.21, and other terms and conditions set forth in this PSD permit in conjunction with the corresponding Texas Commission on Environmental Quality (TCEQ) PSD permit No. PSD-TX-1354. Failure to comply with any condition or term set forth in this PSD Permit may result in enforcement action pursuant to Section 113 of the Clean Air Act (CAA). This PSD Permit does not relieve M&G Resins of the responsibility to comply with any other applicable provisions of the CAA (including applicable implementing regulations in 40 CFR Parts 51, 52, 60, 61, 72 through 75, and 98) or other federal and state requirements (including the state PSD program that remains under approval at 40 CFR § 52.2303).

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

_____ _____

Wren Stenger, Director Date
Multimedia Planning and Permitting Division

M&G Resins USA, L.L.C. PET Plant (PSD-TX-1352-GHG)
Prevention of Significant Deterioration Permit
For Greenhouse Gas Emissions
Draft Permit Conditions

PROJECT DESCRIPTION

The permit allows M&G to construct a new polyethylene terephthalate (PET) production plant. The new PET plant will consist of a new polyethylene terephthalate unit and a new terephthalic acid (PTA) unit. As part of the same project, PSD permit PSD-TX-1354-GHG, authorizes construction of a utility plant support facility, supplying either combined heat and power or steam only.

The new PET production plant, once constructed, is estimated to have a PET production capacity of approximately 1.323 million short tons per year.

EQUIPMENT LIST

The following equipment is subject to this GHG PSD permit.

FIN	EPN	Description
E7-A E7-B E7-C E7-D	E7-A E7-B E7-C E7-D	Four HTF (Heat Transfer Fluid) Heaters. These are 142 MMBtu/hr heat input devices firing either biogas, waste gas, or natural gas, or a mixture thereof.
FLARE	FLARE	Biogas Flare- natural gas fuel for pilot used to flare biogas when heaters are not available.
E1 E2	E1 E2	Two RTOs (Regenerative Thermal Oxidizers) natural gas fired, 18MMbtu/hr combusting PTA plant waste gas
E85-A E85-B	E85-A E85-B	Two Emergency Diesel Generators, limited to 100 hrs per year use for testing and other purposes as described in 40 CFR 63 Subpart ZZZZ.
E87-A E87-B	E87-A E87-B	Two Fire Water Pump Diesel Engines limited to 100 hrs per year use for testing and other purposes as described in 40 CFR 63 Subpart ZZZZ.
FUG-PTA FUG-PET	FUG-PTA FUG-PET	Fugitive equipment leaks from pipe and other equipment, primarily from natural gas fuel system supply.

Deleted: ordinarily fired on methane rich biogas from the waste water treatment plant but may be supplementally fired with natural gas.

Deleted: purposes

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Commented [TS2]: 1.MACT ZZZZ applicability allows select non-emergency operation within the 100 annual hours allowed.
EPA's definition (for NSPS JJJJ or MACT ZZZZ applicability – Assuming genset was constructed after 6/12/2006):
Engines that are operated to provide electrical power or mechanical work during an emergency situation. Examples include engines used to produce power for critical networks or equipment when electric power from the local utility is interrupted, or engines used to pump water in the case of fire or flood. I order to be considered and emergency engine, the following operation requirements must be met:
a.There is no time limit on the use of the engine in emergency situations
b.**The engine may be used for up to 100 hours per calendar year** for any combination of the following purposes:
i.Maintenance checks and readiness testing
ii.Emergency demand response when an Energy Emergency Alert Level 2 has been declared by the Reliability Coordinator
iii.Periods where the voltage or frequency deviates by 5 percent or more below standard
c.The engine may be used for up to 50 hours per calendar year for any combination of the following purposes, but the operation counts as part of the 100 hours per calendar year for maintenance, testing, and emergency demand response:
i.Non-emergency situations, provided there is no financial arrangement with another entity (for example, it can be used during maintenance on primary engine)
ii.Peak shaving in local system operator program until May 3, 2014 if existing engine

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I. GENERAL PERMIT CONDITIONS

A. PERMIT EXPIRATION

As provided in 40 CFR §52.21(r), this PSD Permit shall become invalid if construction:

1. is not commenced (as defined in 40 CFR §52.21(b)(9)) within 18 months after the approval takes effect; or

2. is discontinued for a period of 18 months or more; or

3. is not completed within a reasonable time.

Pursuant to 40 CFR §52.21(r), EPA may extend the 18-month period upon a written satisfactory showing that an extension is justified.

B. PERMIT NOTIFICATION REQUIREMENTS

Permittee shall notify EPA Region 6 in writing or by electronic mail of the:

1. date construction is commenced, postmarked within 30 days of such date;

2. actual date of initial startup, as defined in 40 CFR §60.2, postmarked within 15 days of such date; and

3. date upon which initial performance tests will commence, in accordance with the provisions of Section VI, postmarked not less than 30 days prior to such date. Notification may be provided with the submittal of the performance test protocol required pursuant to Condition VI.C.

C. FACILITY OPERATION

At all times, including periods of startup, shutdown, and maintenance, Permittee shall, to the extent practicable, maintain and operate the facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA, which may include, but is not limited to, monitoring results, review of operating maintenance procedures and inspection of the facility.

D. **MALFUNCTION REPORTING**

1. Permittee shall notify EPA by mail within 48 hours following the discovery of any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner, which results in an increase in GHG emissions above the allowable emission limits or a violation of the exhaust gas temperature limit stated in Sections II and III of this permit.

2. Within 10 days of the restoration of normal operations after any failure described in condition I.D.1., Permittee shall provide a written supplement to the initial notification that includes a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in Section II and III, and the methods utilized to mitigate emissions and restore normal operations.

3. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.

E. **RIGHT OF ENTRY**

EPA authorized representatives, upon the presentation of credentials, shall be permitted:

1. to enter the premises where the facility is located or where any records are required to be kept under the terms and conditions of this PSD Permit;

2. during normal business hours, to have access to and to copy any records required to be kept under the terms and conditions of this PSD Permit;

3. to inspect any equipment, operation, or method subject to requirements in this PSD Permit; and,

4. to sample materials and emissions from the source(s).

F. **TRANSFER OF OWNERSHIP**

In the event of any changes in control or ownership of the facilities to be constructed, this PSD Permit shall be binding on all subsequent owners and operators. Permittee shall notify the succeeding owner and operator of the existence of the PSD Permit and its conditions by letter; a

copy of the letter shall be forwarded to EPA Region 6 within thirty days of the letter signature.

G. SEVERABILITY

The provisions of this PSD Permit are severable, and, if any provision of the PSD Permit is held invalid, the remainder of this PSD Permit shall not be affected.

H. ADHERENCE TO APPLICATION AND COMPLIANCE WITH OTHER ENVIRONMENTAL LAWS

Permittee shall construct this project in compliance with this PSD Permit, the application on which this permit is based, the corresponding TCEQ PSD permits for the project and all other applicable federal, state, and local air quality regulations. This PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

I. ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
BACT	Best Available Control Technology
CAA	Clean Air Act
CC	Carbon Content
CCS	Carbon Capture and Sequestration
CHP	Combined Heat and Power
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CH_4	Methane
CO_2	Carbon Dioxide
CO_{2e}	Carbon Dioxide Equivalent
CT	Combustion Turbine
DLNB	Dry Low-NO_x Burner
dscf	Dry Standard Cubic Foot EF Emission Factor
EPN	Emission Point Number
FIN	Facility Identification Number
Fc	Carbon Dioxide-Based Fuel Factor
FR	Federal Register
GCV	Gross Calorific Value
GHG	Greenhouse Gas
gr	Grains
GWP	Global Warming Potential
HRSG	Heat Recovery Steam Generator
HHV	High Heating Value
hr	Hour
lb	Pound
LDAR	Leak Detection and Repair
MMBtu	Million British Thermal Units
MSS	Maintenance, Start-up and Shutdown
N_2O	Nitrous Oxides
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
PSD	Prevention of Significant Deterioration
QA/QC	Quality Assurance and/or Quality Control
SCFH	Standard Cubic Feet per Hour
SCR	Selective Catalytic Reduction
SF_6	Sulfur Hexafluoride
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TPY	Tons per Year
USC	United States Code
VOC	Volatile Organic Compound

II. Annual Emission Limits

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

FIN	EPN	Description	GHG Mass Basis		TPY [1,2,3] CO_2e	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_2O	0.14	41.72	
E7-B[4]	E7-B	HTF Heater	CO_2	72,622	72,622	
			CH_4	1.37	34.25	
			N_2O	0.14	41.72	
E7-C[4]	E7-C	HTF Heater	CO_2	72,622	72,622	
			CH_4	1.37	34.25	
			N_2O	0.14	41.72	
E7-D[4]	E7-D	HTF Heater	CO_2	72,622	72,622	
			CH_4	1.37	34.25	
			N_2O	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. See permit condition III.C.
			CH_4	83	2,075	
			N_2O	0.54	160.92	
E2[5]	E2	RTO 2	CO_2	54,495	54,495	
			CH_4	83	2,075	
			N_2O	0.54	160.92	
FLARE[6]	FLARE	Biogas Flare-Flaring including nat gas pilot	CO_2	8,942	8,942	Good combustion and maintenance practices. See permit condition III.B
			CH_4	13.60	340.00	
			N_2O	0.09	26.52	
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.
			CH_4	0.1	2.5	
			N_2O	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. See permit condition III.D.
			CH_4	0.1	2.5	
			N_2O	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.
			CH_4	0.01	0.25	
			N_2O	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. See permit condition III.E.
			CH_4	0.01	0.25	
			N_2O	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**	**414,101**	**CO_2e**	
			CH_4	**185**	**419,262**	
			N_2O	**2**		

Commented [TS3]: Please update Table to match the values in the SOB.

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): CO_2=1, CH_4 = 25, N_2O = 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 CH4 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.

Deleted: methane rich biogas from the waste water treatment plant as normal fuel or

Deleted: RTOs

Deleted: RTOs

III. SPECIAL PERMIT CONDITIONS

A. HTF (Heat Transfer Fluid) Heaters (EPNs: E7-A, E7-B, E7-C and E7-D) Work Practice Standards, Operational Requirements, and Monitoring

1. The HTF Heaters shall combust pipeline quality natural gas, process gas from the PTE Unit or waste water treatment plant (WWTP) generated biogas, Contributions of combustibles to the combustion air from the PTA unit waste streams shall also be permitted.
2. The HTF Heaters shall have fuel metering and the Permittee shall:
   a. Measure and record the fuel flow rate by type using an operational non-resettable elapsed flow meter. A computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer.
   b. Record the total fuel combusted monthly, subtotaled by type.
   c. Records of the fuel GCV by type shall be maintained for a minimum period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in any unit covered by this permit at the time of the request, or shall allow a sample to be taken by EPA for analysis.
   d. Establish the rate and quantity of waste gas contribution to combustion air to the products of combustion by gas analysis on an annual basis, and its contribution to the maximum allowable emissions limits established in Table 1, which may not be exceeded and limits all products of combustion for GHG.
3. Permittee shall calibrate and perform a preventative maintenance check of the fuel gas flow meters and document annually.
4. Each HTF Heater shall not exceed a maximum firing rate of 142 MMBtu/hr (HHV, 1-hr average), including any contribution from waste gas used as combustion air. CO_2 lb per MMBtu heat input shall be limited to 116.9 lb CO_2/MMBtu on a 12-month rolling average basis.
5. Excess oxygen in the exhaust gas shall be monitored continuously and recorded to ensure the levels stay between 1-5% on an hourly average basis.
6. Thermal efficiency of the HTF Heaters shall be demonstrated by monitoring the inlet and exhaust gas temperatures. Exhaust Temperatures will be limited to 320° F, averaged on a 12-month rolling average basis.
7. Compliance with the Annual Emission Limit shall be demonstrated on a 12-month total, rolling monthly, calculated in accordance with equation C-5 found in 40 CFR §98.33(a)(3)(iii), and shall include the contribution, if any, from waste gas used as combustion air.

Commented [TS4]: 1-5 % O2 is expected during normal operation

Deleted: 3

B. Biogas Flare (EPN: FLARE) Work Practice Standards, Operational Requirements, and Monitoring

1. The biogas flare (EPN: FLARE) shall have a minimum Destruction and Removal Efficiency (DRE) of 98% for VOCs and 99 % for methane based on compliance with condition 2 below.

Commented [TS5]: 99% destruction of methane is consistent with TCEQ flare guidance and permit representations.

Deleted: 1

Deleted: 5

2. The flare shall be designed and operated in accordance with 40 CFR 60.18 including specifications of minimum heating value of the waste gas, maximum tip velocity, and while the flare is operating, continuously monitor pilots for presence of flame by thermocouple or equivalent. An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes.
3. The biogas flare shall combust pipeline-quality natural gas in the flare pilots. The flare may combust the biogas ordinarily routed to the heaters as fuel when the heaters are unable to control the biogas so generated. Biogas may be combusted either as fuel in the heaters, or during MSS, in the flare, but not to both simultaneously.
4. CO_2 emissions are to be calculated using methods found in 40 CFR § 98.253(b). CH_4 and N_2O emissions are calculated using equations Y-4 and Y-5 as found in 40 CFR Part 98 Subpart Y. GHG emissions are to be determined monthly.
5. The nature and quantity of materials routed to the flare, either as natural gas, or as waste gas to be controlled by the flare shall be determined continuously. The equipment so used shall be operated and maintained in accordance with 40 CFR §98.254, as appropriate.

C. Regenerative Thermal Oxidizers (RTOs), (EPNs: E1 and E2) Work Practice Standards, Operational Requirements, and Monitoring

1. The regenerative thermal oxidizers (RTOs) may combust pipeline quality natural gas and/or process waste gases vented from the PTA Unit.
2. The RTOs shall have an initial stack test to verify destruction and removal efficiency (DRE) of at least 98% for VOCs and CO in the outlet, and at least 99% for methane. If the flow of vented gases to the RTOs exceed the flow rate established during testing by 10% or greater, additional sampling may be required by TCEQ or EPA.
3. For burner combustion, natural gas fuel usage (scf) shall be recorded using an operational, non-resettable elapsed flow meter at the RTOs. A computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer. The flow rate of the fuel gas combusted, as well as the specific heat content values shall be continuously measured and recorded using fuel flow meters at the RTOs in conjunction with fuel sampling and analysis. A computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer. The combined total emissions of the combustion of natural gas and waste gas shall be limited by the emissions limitations established in Table 1.
4. Waste gas will be sampled and analyzed at least quarterly for composition. The sampled data will be used, along with the data of natural gas usage in the same time frame to calculate GHG emissions to show compliance with the limits specified in Table 1.
5. Permittee shall calculate CO_2 emissions, on a monthly basis, using equation C-5 consistent with 40 CFR § 98.33(a)(3)(iii), with results converted to units of the standards required in Table 1.

Commented [TS6]: 98+% destruction of VOCs is consistent with permit representations.

Commented [TS7]: 99% destruction of methane is consistent with permit representations.

Deleted: 99

Deleted: .5

6. Periodic maintenance and/or inspections will help maintain the efficiency of the regenerative thermal oxidizers and shall be performed at a minimum annually or more often as recommended by the manufacturer specifications or equivalent.
7. The Permittee shall maintain the combustion temperature above the one-hour average temperature maintained in the initial stack test, as required by the TCEQ NSR Permit No. 108466, based on the minimum chamber temperature on a 15-minute average. Prior to the stack test, the minimum 15-minute average combustion temperature will be no less than 1,400 ºF (760 ºC). Continuous temperature monitoring and recording of the RTOs will ensure proper operation.
8. The Permittee shall install and maintain a temperature recording device with an accuracy of ±2.5ºC or ±0.75 percent of the temperature being measured expressed in degrees Celsius.

D. Emergency Diesel Generators (EPNs: E85-A and E85-B) Work Practice Standards, Operational Requirements, and Monitoring

1. The Permittee shall limit the operation of the Emergency Diesel Generators to no more than 100 hours per 12-month rolling average each in order to perform maintenance checks and readiness tests and select non-emergency operation as specified in MACT ZZZZ.

2. The Permittee shall use engines that meet the requirements of New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines 40 CFR Part 60 Subpart IIII, and shall perform all annual maintenance as required by the applicable requirement of 40 CFR Part 60, Subpart IIII.

E. Fire Water Pump Diesel Engines (EPNs: E87-A and E87-B) Work Practice Standards, Operational Requirements, and Monitoring

1. The Permittee shall limit the operation of the Fire Water Pump Diesel Engines to no more than 100 hours per 12-month rolling average each in order to perform maintenance checks and readiness tests and select non-emergency operation as specified in MACT ZZZZ.

2. The Permittee shall use engines that meet the requirements of New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines 40 CFR Part 60 Subpart IIII, and shall perform all annual maintenance as required by the applicable requirement of 40 CFR Part 60, Subpart IIII.

F. Combined Plant Fugitives (EPNs: FUGPTA and FUGPET) Work Practice Standards, Operational Requirements, and Monitoring

1. The Permittee shall implement an auditory, visual, and olfactory (AVO) method for detecting leaks in equipment in methane or natural gas service and fugitive emission of methane from process lines not in VOC service but containing methane.

2. The Permittee shall implement the TCEQ 28VHP leak detection and repair (LDAR) program for fugitive emissions of methane for process lines in VOC service (defined as >10wt% VOC) in lieu of AVO monitored if required to do so by a TCEQ issued PSD criteria pollutant permit.

3. AVO monitoring shall be performed weekly.

IV. Recordkeeping and Reporting

1. In order to demonstrate compliance with the GHG emission limits in Table 1, the Permittee shall maintain the following parameters on a calendar month basis:

    a. Records of operating hours for air emission sources listed in Table 1;
    b. Records of the usage of pipeline quality natural gas, gas being combusted in the HTF Heaters (either as fuel or as part of combustion air) and in the biogas flare, measured in accordance with the Special Conditions in Section III of this permit;
    c. The fuel usage for the RTOs and waste gas combusted in the RTOs and biogas flare, using continuous fuel flow monitors (a group of equipment can utilize a common fuel flow meter, as long as actual fuel usage is allocated to the individual equipment based upon actual operating hours and maximum firing rate) A computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer; and,
    d. Semi-annual fuel sampling for natural gas, daily fuel sampling of blended fuel gas, or other frequencies as allowed by 40 CFR § 98.34(b)(3) or other frequencies allowed by this permit. Vendor analysis of supplied fuel is an acceptable alternative to site specific sampling.

2. For the EPNs listed in Table 1 and as required by this permit, the Permittee shall maintain records of the following for GHG emissions from the Equipment List (excluding fugitives): all records or reports pertaining to significant maintenance performed; duration of startup, shutdown; the initial startup period for the emission units; malfunctions; all records relating to performance tests, calibrations, checks, and monitoring of combustion equipment; duration of an inoperative monitoring device and emission units with the required corresponding emission data; and all other information required by this permit recorded in a permanent form suitable for inspection. These records may be maintained in electronic databases. The records must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.

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

4. Permittee shall maintain records and submit a written report of all excess emissions to EPA semi-annually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator or authorized representative, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the

compliance status of the source. The report is due on the 30th day following the end of each semi-annual period and shall include the following:

a. Time intervals, data and magnitude of the excess emissions, the nature and cause (if known), corrective actions taken and preventive measures adopted;
b. Applicable time and date of each period during which the monitoring equipment was inoperative (monitoring down-time) while equipment was operating;
c. A statement in the report of a negative declaration; that is; a statement when no excess emissions occurred or when the monitoring equipment has not been inoperative, repaired or adjusted;
d. Any failure to conduct any required source testing, monitoring, or other compliance activities; and,
e. Any violation of limitations on operation.

5. Excess emissions shall be defined as any period in which the facility emissions exceed a maximum emission limit set forth in this permit, a malfunction occurs of an emission unit listed in the Equipment List that results in excess GHG emissions, or any other unauthorized GHG emissions occur.

6. Excess emissions indicated by GHG emission source certification testing or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.

7. Instruments and monitoring systems required by this PSD permit shall have a 95% on-stream time on a 12-month rolling basis.

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

V. Initial Performance Testing Requirements:

A. The Permittee shall perform stack sampling and other testing to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the Heat Transfer Fluid (HTF) Heaters (EPNs: E7-A, E7-B, E7-C and E7-D) and the Regenerative Thermal Oxidizers (RTOs) (EPNs: E1 and E2) to determine the initial compliance with the CO_2 emission limits established in this permit. Sampling shall be conducted in accordance with 40 CFR § 60.8 and EPA Method 3a or 3b for the concentration of CO_2.

1. Multiply the CO_2 hourly average emission rate determined under maximum operating test conditions by 8,760 hours.
2. If the above calculated CO_2 emission total does not exceed the tons per year (TPY) specified on Table 1, no compliance strategy needs to be developed.
3. If the above calculated CO_2 emission total exceeds the tons per year (TPY) specified in Table 1, the facility shall;

    a. Document the exceedance in the test report; and

b. Explain within the report how the facility will assure compliance with the CO_2 emission limit listed in Table 1.

B. Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility, performance tests(s) must be conducted and a written report of the performance testing results furnished to the EPA. Additional sampling may be required by TCEQ or EPA.

C. Permittee shall submit a performance test protocol to EPA no later than 30 days prior to the test to allow review of the test plan and to arrange for an observer to be present at the test. The performance test shall be conducted in accordance with the submitted protocol, and any changes required by EPA.

D. The Heat Transfer Fluid Heaters (EPNs: E7-A, E7-B, E7-C and E7-D) and the Regenerative Thermal Oxidizers (EPNs: E1 and E2) shall operate at representative production rates during stack emission testing, with the fuel being fired clearly included in the test results. Ordinarily, this will mean firing the heaters on biogas fuel supplemented as needed with natural gas, and for the RTOs, operating at normal conditions with waste gas providing the primary fuel and, if needed, natural gas as supplemental fuel.

E. Performance testing must be conducted using flow rates that are comparable to the normal operating flow rates.

F. Waste gas sampling shall be conducted in accordance with 40 CFR Part 98.

F. Stack testing of the Regenerative Thermal Oxidizers (EPNs: E1 and E2) will establish minimum combustion temperature for the RTOs. Stack testing will be performed initially and within 120 days of a process flow changes as identified in III.C.2. The permittee shall provide EPA with a copy of the stack testing results.

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

I. The owner or operator must provide the EPA at least 30 days prior notice of any performance test required by this permit, except as specified under other subparts, to afford the EPA the opportunity to have an observer present and/or to attend a pre-test meeting. If there is a delay in the original test date, the facility must provide at least 7 days prior notice of the rescheduled date of the performance test unless EPA approves an earlier rescheduled date.

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

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

2. Safe sampling platform(s),
3. Safe access to sampling platform(s), and
4. Utilities for sampling and testing equipment.

K. Unless otherwise specified, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For purposes of determining compliance with an applicable standard, the arithmetic mean of the results of the three runs shall apply.

L. Emissions testing, as outlined above, shall be performed every five years, plus or minus 6 months, of when the previous performance test was performed, or within 180 days after the issuance of a permit renewal, whichever comes later to verify continued performance at permitted emission limits.

VI. Agency Notifications

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

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

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

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

Toups, Brad

From: Larry Moon <lmoon@zephyrenv.com>
Sent: Tuesday, September 16, 2014 5:30 PM
To: Toups, Brad
Cc: Thomas Sullivan; Flavio Assis (Flavio.Assis@gruppomg.com.br); Allana.ratliff@chemtex.com
Subject: RE: M&G Resins Utility Plant Draft Permit and Statement of Basis are ready for your review and comment
Attachments: Table 3-2 9-16-2014.pdf; ZEC Copy of MG PTE Plant PSD GHG MAER Table July 7 2014 Updated 091114.pdf

Brad,

See responses to your questions in your September 11, 2014 email below:

What is the status of the M&G PET Plant draft GHG permit?

Hi Larry, others,
I appreciate your review of the drafts, and tell Ed Rapier thanks for his close review. I have incorporated your changes, pretty much as suggested. I think it would be good to get from you a new table 3-2 for the turbine and duct burners that indicates the heat input to the turbine separately from the duct burners. This might be done as a footnote to the table. At this point, the size of the duct burners is only mentioned in passing in the narrative, and having this text as part of Table 3-2 would make it clear the size of the various components that share the common stack.

As requested, attached is a revised Table 3-2, Turbine and Duct Burner Annual GHG Annual Emission Calculations for the Utility Plant. Footnote 1 shows the annual average turbine and duct burner firing rates that were used to calculate annual GHG emissions. Footnote 2 shows the maximum hourly turbine and duct burner firing rates.

With regard to the difference in the sums in Table 1a, the easiest way to explain it is for me to simply include the spreadsheet, which I have, and if you highlight cell E52 and hit the F2 key, you can see which I included In the totals.

On the attached spreadsheet, the Total PET Plant Emissions calculations were updated to include the Natural gas firing in the RTO's (EPNs E1 and E2) as the natural gas can and will be fired concurrently with the waste gas as needed to maintain operating temperatures.
The Biogas stream to flare (EPN Flare) was removed from the total emission calculations and the waste gas stream firing in the HTF heaters (EPN E7A-D) was added. This is nearly a 1 for 1 swap but the waste gas stream includes the biogas stream (which can be routed to the flare) and minor process vent streams that are only routed to the HTF heaters and therefore is most representative of the total potential emissions.

With regards to using LHV vs HHV on the thermal efficiency calculations, you may wish to confirm that your comparisons to other BACT evaluations are on the same heat input basis (HHV or LHV) and if they are different, how your comparison is valid.

The thermal efficiencies for steam boilers in the BASF Fina LP GHG Permit (PSD-TX-903-GHG) and Chevron Phillips Chemical Co., Cedar Bayou Plant Permit (PSD-TX-748-GHG) are calculated using the gross heating value for the fuel, so those thermal efficiencies are on a Higher Heating Value (HHV) basis. The draft permit for the M & G Utility Plant specifically listed the thermal efficiency limits for AUXBLRA1, AUXBLRA2 and AUXBLRB in Tables 1.A. and 1.B. and in Condition III.E.1. as being on a Lower Heating Value (LHV) basis. The efficiency compliance method listed in Condition III.E.2. is actually for heaters rather than boilers, but that method could be used to calculate a thermal efficiency on either a HHV basis or a LHV basis. If the intent was to list the boiler thermal efficiencies on a HHV basis, then the references to LHV on Tables 1.A., 1.B., and Condition III.E.1 needs to be changed to "HHV".

I reviewed the BASF Fina LP GHG Permit (PSD-TX-903-GHG) for the combined heat and power combustion turbine and the permit does not specify whether the thermal efficiency limit of 60% is on a HHV basis or a LHV basis. The compliance method in the permit uses the term " Heat Content of Fuel Supply" and does not specify whether that heat content is on a HHV or LHV basis. The draft permit for the M & G Utility Plant is inconsistent in that the thermal efficiency limit for the CTG is specifically listed on Table 1.A. as being on a LHV basis but the compliance method in Condition III.B.11 is on a HHV basis. If the intent was for the efficiency limit to be on a HHV basis, then the reference to LHV in Table 1.A. needs to be changed to "HHV".

I will let you know when we expect to go to public notice. I will also forward for your review the PET plant drafts, as they are still in legal review internally.

From: Toups, Brad [mailto:Toups.Brad@epa.gov]
Sent: Thursday, September 11, 2014 3:33 PM
To: Larry Moon
Cc: Thomas Sullivan; Flavio Assis (Flavio.Assis@gruppomg.com.br); Martha.Martinez@gruppomgus.com; Allana.ratliff@chemtex.com; mauro.fenoglio@gruppomg.com
Subject: RE: M&G Resins Utility Plant Draft Permit and Statement of Basis are ready for your review and comment

Hi Larry, others,
I appreciate your review of the drafts, and tell Ed Rapier thanks for his close review. I have incorporated your changes, pretty much as suggested. I think it would be good to get from you a new table 3-2 for the turbine and duct burners that indicates the heat input to the turbine separately from the duct burners. This might be done as a footnote to the table. At this point, the size of the duct burners is only mentioned in passing in the narrative, and having this text as part of Table 3-2 would make it clear the size of the various components that share the common stack.

With regard to the difference in the sums in Table 1a, the easiest way to explain it is for me to simply include the spreadsheet, which I have, and if you highlight cell E52 and hit the F2 key, you can see which I included In the totals.

With regards to using LHV vs HHV on the thermal efficiency calculations, you may wish to confirm that your comparisons to other BACT evaluations are on the same heat input basis (HHV or LHV) and if they are different, how your comparison is valid.

I will let you know when we expect to go to public notice. I will also forward for your review the PET plant drafts, as they are still in legal review internally.

Brad

From: Larry Moon [mailto:lmoon@zephyrenv.com]
Sent: Wednesday, September 10, 2014 5:01 PM
To: Toups, Brad
Cc: Thomas Sullivan; Flavio Assis (Flavio.Assis@gruppomg.com.br); Martha.Martinez@gruppomgus.com; Allana.ratliff@chemtex.com; mauro.fenoglio@gruppomg.com
Subject: RE: M&G Resins Utility Plant Draft Permit and Statement of Basis are ready for your review and comment

Brad,

Attached are our comments on the draft permit and SOB for the M&G Utility Plant. In addition, in the SOB Table 1.a., the total CO2e represented at the bottom of the Table does not appear to be accurate. The CO2e listed on the table is **419,262**. When we sum the TPY CO2e listed in the column and subtract the 9,309 TPY associated with the Biogas Burning in the Flare, we get **438,280**.

From: Toups, Brad [mailto:Toups.Brad@epa.gov]
Sent: Wednesday, September 10, 2014 8:51 AM
To: Larry Moon
Subject: RE: M&G Resins Utility Plant Draft Permit and Statement of Basis are ready for your review and comment

Hi Larry,
It may be that the file format we use (.docx) could have something to do with it. This is the file extension that word 2013 uses, which is our current version. I saved the same file as an older version with a (.doc) extension. See if this helps. I bet the problem is in how it treats the tables I created.
Brad

From: Larry Moon [mailto:lmoon@zephyrenv.com]
Sent: Wednesday, September 10, 2014 8:46 AM
To: Toups, Brad
Subject: RE: M&G Resins Utility Plant Draft Permit and Statement of Basis are ready for your review and comment

Thanks Brad. For some reason my version of Word does not pull up the SOB file correctly, but others here do not have that problem.

From: Toups, Brad [mailto:Toups.Brad@epa.gov]
Sent: Wednesday, September 10, 2014 8:22 AM
To: Larry Moon; Thomas Sullivan
Cc: Robinson, Jeffrey
Subject: RE: M&G Resins Utility Plant Draft Permit and Statement of Basis are ready for your review and comment

Sure, I will send a new copy, one as word, the other as a pdf of the word. See attached.

Let me know if these work.
Brad

From: Larry Moon [mailto:lmoon@zephyrenv.com]
Sent: Wednesday, September 10, 2014 8:16 AM
To: Toups, Brad; Thomas Sullivan
Cc: Robinson, Jeffrey
Subject: RE: M&G Resins Utility Plant Draft Permit and Statement of Basis are ready for your review and comment

Brad,

There is a problem with the Word file. I am only seeing 9 pages. Can you send a pdf copy of the SOB?

Larry Moon P.E. | Principal
Zephyr Environmental Corporation
2600 Via Fortuna, Ste 450 | Austin, TX 78746
Direct: 512.879.6619 | lmoon@zephyrenv.com
ZephyrEnv.com | HazMatAcademy.com

From: Toups, Brad [mailto:Toups.Brad@epa.gov]
Sent: Wednesday, September 10, 2014 7:57 AM
To: Larry Moon; Thomas Sullivan

Cc: Robinson, Jeffrey
Subject: RE: M&G Resins Utility Plant Draft Permit and Statement of Basis are ready for your review and comment

Hi Larry,

I took a quick scan thru the 26 page SOB we sent on the utility plant, and it looks complete. The SOB on this is relatively short, but that is because it entails only a few source. The SOB on the Resins plant will be longer.

Was there a specific section you thought was cut off?
Thanks
Brad

From: Toups, Brad
Sent: Friday, September 05, 2014 4:13 PM
To: Larry Moon; 'Thomas Sullivan'
Cc: Robinson, Jeffrey
Subject: RE: M&G Resins Utility Plant Draft Permit and Statement of Basis are ready for your review and comment

Hi All,
Apparently the imbedded acrobat file that was the site location map in the SOB is not permitted to pass your server, and so my original email was kicked back to me. Therefore, I have replaced the graphic with the error message I got from your email server. Looks like I will need to find a way to convert the acrobat graphic into a plain jpg or something. Otherwise, the files are ready for your review.

Brad

From: Toups, Brad
Sent: Friday, September 05, 2014 4:02 PM
To: Larry Moon; 'Thomas Sullivan'
Cc: Robinson, Jeffrey
Subject: M&G Resins Utility Plant Draft Permit and Statement of Basis are ready for your review and comment

Hi Larry, Thomas,

We are ready for your review and comment on the Utility plant permit documents. The Resins plant related documents are still in legal review here at the EPA. We would appreciate you providing your comments to us by COB Wed, Sept 10, if at all possible.

Also, we anticipate the large discrepancy in the original estimate of CCS (The 2013 app, approx. $150MM) and the revised cost estimate (May 2014, >$600 MM) should have a more detailed rationale in the record. Providing that rationale in the record prior to going to public notice may allow the public to better understand why the more recent estimate is validly and substantially more accurate.

Thanks for your comments in advance,

Brad Toups
Air Permit Section
Multimedia Planning and Permitting Division
US EPA, Region 6
1445 Ross Ave, Suite 1200 (6PD-R)
Dallas, Tx 75202
214.665.7258

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

Table 1 M&G PET Plant Annual Emissions and BACT Summary							CO_2 Mass Emissions		
FIN	**EPN**	**Description**	**GHG Mass Basis**		**TPY CO_2e**	**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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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_2O	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.			
			CH_4	0.01	0.25				
			N_2O	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. See permit condition III.E.			
			CH_4	0.01	0.25				
			N_2O	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.			
FUGPET	FUGPET		CH_4	20.27	506.75				
Totals			**CO_2**	**432,947**	**CO_2e 438,280**				
			CH_4	**193**					
			N_2O	**2**					

Notes:

1 Waste gas 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 waste gas which offsets heater natural gas use.

2 Biogas 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.

3 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 (predominately methane) being treated by the RTO, therefore the emissions attributable to waste gas include the natural gas supplementally fired.

TABLE 3-2
TURBINE AND DUCT BURNER GHG ANNUAL EMISSION CALCULATIONS
UTILITY PLANT

EPN	Average Heat Input (MMBtu/hr)[1, 2]	Annual Heat Input[3] (MMBtu/yr)	Pollutant	Emission Factor (kg/MMBtu)[4]	GHG Mass Emissions (tpy)	Global Warming Potential[5]	CO_2e (tpy)
CTG	710.3	6,222,228	CO_2	53.02	363,651.6	1	363,651.6
			CH_4	1.0E-03	6.86	25	171.5
			N_2O	1.0E-04	0.69	298	204.4
				Totals	**363,659.1**		**364,027.4**

Notes

1. Heat input is based on an annual average turbine firing rate of 465 MMBtu/hr and an annual average duct burner firing rate of 245.3 MMBtu/hr from Firing Case 4CT, 100% load, with inlet chiller on.
2. The maximim hourly firing rates for the turbine and duct burner are 485 MMBtu/hr and 263 MMBtu/hr, respectively
3. The annual heat input includes hours of turbine startup/shutdown.
4. Factors based on natural gas values in Table C-1 and C-2 of 40 CFR Part 98, Mandatory Greenhouse Gas Reporting.
5. Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

Sample Calculation, CO_2e:

CH4 (ton/yr) = 6,222,228 MMBtu/yr x 0.001 kg/MMBtu x 2.2046 lb/kg / 2000 lb/ton = 6.86 tpy

CO2e (ton/yr) = 6.86 tpy x 25 = 171.5 tpy CO2e

Toups, Brad

From: Thomas Sullivan <tsullivan@zephyrenv.com>
Sent: Friday, July 18, 2014 4:22 PM
To: Toups, Brad
Cc: Larry Moon
Subject: RE: M&G resin: request for a clearer version of Plot Plan Map 1 of 2
Attachments: Plot Plan OVERVIEW Map 1.pdf

Hi Brad,

Will this work? It does print best at 11x17.

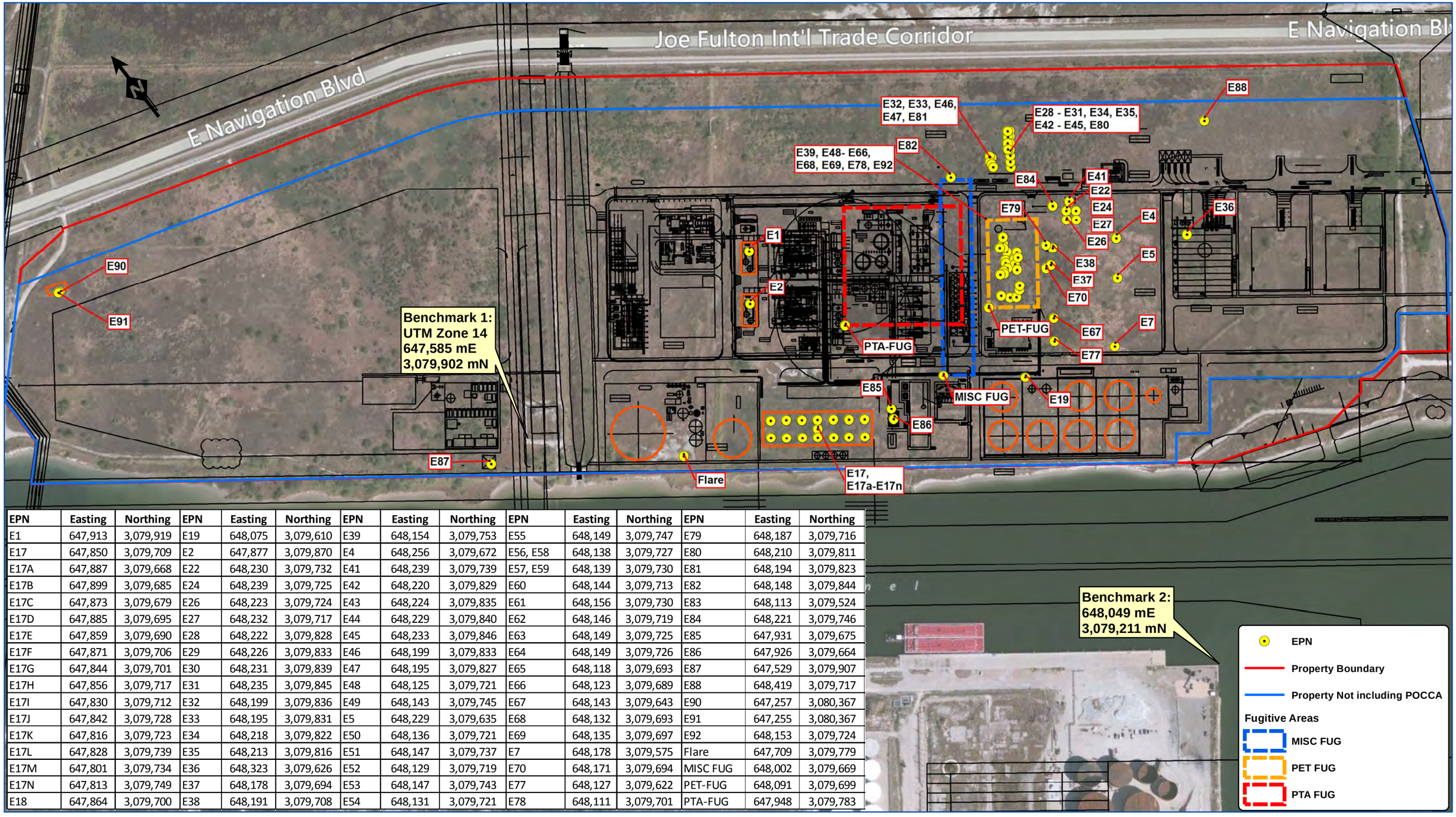
Regards,

Thomas

Thomas Sullivan P.E. | Principal
Zephyr Environmental Corporation
2600 Via Fortuna, Ste 450 | Austin, TX 78746
Direct: 512.879.6632 | tsullivan@zephyrenv.com
ZephyrEnv.com | HazMatAcademy.com

From: Toups, Brad [mailto:Toups.Brad@epa.gov]
Sent: Friday, July 18, 2014 9:12 AM
To: Thomas Sullivan
Subject: M&G resin: request for a clearer version of Plot Plan Map 1 of 2

Hi Thomas,
Can you send me a clearer version of the Plot Plan Map 1 of 2 found in the original permit application? The text showing the EPNs and EPN names is not of sufficient resolution as to be readable.
Thanks
Brad Toups



EPN	Easting	Northing	EPN	Easting	Northing	EPN	Easting	Northing	EPN	Easting	Northing	EPN	Easting	Northing
E1	647,913	3,079,919	E19	648,075	3,079,610	E39	648,154	3,079,753	E55	648,149	3,079,747	E79	648,187	3,079,716
E17	647,850	3,079,709	E2	647,877	3,079,870	E4	648,256	3,079,672	E56, E58	648,138	3,079,727	E80	648,210	3,079,811
E17A	647,887	3,079,668	E22	648,230	3,079,732	E41	648,239	3,079,739	E57, E59	648,139	3,079,730	E81	648,194	3,079,823
E17B	647,899	3,079,685	E24	648,239	3,079,725	E42	648,220	3,079,829	E60	648,144	3,079,713	E82	648,148	3,079,844
E17C	647,873	3,079,679	E26	648,223	3,079,724	E43	648,224	3,079,835	E61	648,156	3,079,730	E83	648,113	3,079,524
E17D	647,885	3,079,695	E27	648,232	3,079,717	E44	648,229	3,079,840	E62	648,146	3,079,719	E84	648,221	3,079,746
E17E	647,859	3,079,690	E28	648,222	3,079,828	E45	648,233	3,079,846	E63	648,149	3,079,725	E85	647,931	3,079,675
E17F	647,871	3,079,706	E29	648,226	3,079,833	E46	648,199	3,079,833	E64	648,149	3,079,726	E86	647,926	3,079,664
E17G	647,844	3,079,701	E30	648,231	3,079,839	E47	648,195	3,079,827	E65	648,118	3,079,693	E87	647,529	3,079,907
E17H	647,856	3,079,717	E31	648,235	3,079,845	E48	648,125	3,079,721	E66	648,123	3,079,689	E88	648,419	3,079,717
E17I	647,830	3,079,712	E32	648,199	3,079,836	E49	648,143	3,079,745	E67	648,143	3,079,643	E90	647,257	3,080,367
E17J	647,842	3,079,728	E33	648,195	3,079,831	E5	648,229	3,079,635	E68	648,132	3,079,693	E91	647,255	3,080,367
E17K	647,816	3,079,723	E34	648,218	3,079,822	E50	648,136	3,079,721	E69	648,135	3,079,697	E92	648,153	3,079,724
E17L	647,828	3,079,739	E35	648,213	3,079,816	E51	648,147	3,079,737	E7	648,178	3,079,575	Flare	647,709	3,079,779
E17M	647,801	3,079,734	E36	648,323	3,079,626	E52	648,129	3,079,719	E70	648,171	3,079,694	MISC FUG	648,002	3,079,669
E17N	647,813	3,079,749	E37	648,178	3,079,694	E53	648,147	3,079,743	E77	648,127	3,079,622	PET-FUG	648,091	3,079,699
E18	647,864	3,079,700	E38	648,191	3,079,708	E54	648,131	3,079,721	E78	648,111	3,079,701	PTA-FUG	647,948	3,079,783

Map Sources:
ESRI - BING
Hybrid Basemap
Datum: GCS NAD 1983
UTM Zone 14

0 150 300 Meters

0 500 1,000 Feet

N

zephyr

PLOT PLAN OVERVIEW - MAP 1

M & G RESINS, U.S.A. - Corpus Christi, Texas

Document Path: H:\Chemtex\GIS\ArcGIS\Plot Plans\Plot Plan OVERVIEW Map 1.mxd

Drafted By: J. Knowles	Reviewed By: T. Sullivan	Project No.: 012453.002	Date: 7/18/2014

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.:	108446	Application Submittal Date:	June 2014
Company	M&G Resins USA, LLC		
RN:	1066154438	Facility Location:	
City	Corpus Christi	County:	Nueces
Permit Unit I.D.:	Various	Permit Name:	PET Plant
Permit Activity:	☑ New Major Source	☐ Modification	
Project or Process Description: New PET plant, PTA plant, and new combined cycle turbines			

Complete for all pollutants with a project emission increase.	**POLLUTANTS**							
	Ozone		**CO**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**H2SO4**
	VOC	**NOx**						
Nonattainment? (yes or no)	No	No	No	No	No	No	No	No
Existing site PTE (tpy)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Proposed project increases from M&G (tpy from 2F)[3]	349.56	70.80	344.44	85.85	23.52	23.51	24.38	0.00
Is the existing site a major source?[2] If not, is the project a major source by itself? (yes or no)	Yes							
If site is major, is project increase significant? (yes or no)	YES	YES	YES	YES	YES	YES	NO	NO
If netting required, estimated start of construction:	N/A							
5 years prior to start of construction:	N/A	Contemporaneous						
Estimated start of operation:	8/1/14	Period						
Net contemporaneous change, including proposed project, from Table 3F (tpy)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FNSR applicable? (yes or no)	YES	YES	YES	YES	YES	YES	NO	NO

1. Other PSD pollutants
2. Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR §51.166(b)(1).
3. Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR §51.166(b)(23).

The presentations made above and on the accompanying tables are true and correct to the best of my knowledge.

Signature Title Date