Formosa Plastics

Formosa Plastics Corporation, Texas
201 Formosa Drive • P.O. Box 700
Point Comfort, TX 77978
Telephone: 361-987-7000

November 30, 2012

Certified Mail Number: 7011 0110 0000 1782 9978

Mr. Jeff Robinson
Chief, Air Permits Section
U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

RE: Greenhouse Gas Permit Application
2012 Expansion Project
Gas Turbines
Formosa Plastics Corporation, Texas
Point Comfort, Calhoun County, Texas

Dear Mr. Robinson:

Formosa Plastics Corporation, Texas (FPC TX) currently operates a number of chemical plants at a chemical complex in Point Comfort, Calhoun County, Texas. As we discussed during our June 27, 2012 meeting in your office, FPC TX proposes to expand the FPC TX chemical complex within the existing Point Comfort site footprint. This 2012 Expansion Project will consist of two new Combined Cycle Gas Turbines (Gas Turbines), a new Low Density Polyethylene (LDPE) plant, and an Olefins Expansion (a new Olefins 3 plant and an associated Propane Dehydrogenation (PDH) unit).

As described in the July 13, 2012 Kelly Hart & Hallman memo to Mr. Brian Tomasovic of EPA, the 2012 Expansion Project consists of the three new related plants (identified above) which comprise a single greenhouse gas Prevention of Significant Deterioration (PSD) project. In order to align FPC TX organizational responsibility and accountability for compliance with future permit requirements related to these plants, FPC TX is requesting three separate permits for the proposed new plants. Therefore, three separate permit applications are being submitted. Even though three separate applications are being submitted, FPC TX will perform and satisfy PSD permitting requirements including ambient air quality impacts analysis in aggregate for all the plants.

This letter transmits the FPC TX's application for a Greenhouse Gas (GHG) PSD permit for the Gas Turbines at FPC TX's Point Comfort complex. The Olefins Expansion and LDPE plant GHG permit applications are being submitted under separate cover to the EPA. The Gas Turbines PSD application for criteria pollutant emissions is being be submitted to the Texas Commission on Environmental Quality (TCEQ).

General information for the application is provided on the TCEQ Form PI-1 - General Application for Air Preconstruction Permit and Amendments. The U.S. Environmental Protection Agency's (EPA) document entitled *"PSD and Title V Permitting Guidance for Greenhouse Gases", dated November 2010 and March 2011,* was utilized as a guide for preparation of the attached application.

FPC TX is committed to working closely with EPA Region 6 so that permit application review can be completed as expeditiously as possible. FPC TX anticipates the start of construction in the third quarter of 2013.

Also, as it relates to the permit review timelines, FPC TX would like to report on the progress that has been made on "cross-cutting" federal issues since our meeting in your offices on June 27, 2012. FPC TX has been in discussion with NOAA and USFWS concerning their expectations for assessments related to this expansion and will be addressing their specific concerns in our final biological assessment (BA). As you know, FPC TX has already performed a preliminary biological assessment analysis based on an action area with a radius of 7 miles around the FPC TX Point Comfort Site. Preliminary modeling indicates that the final action area based on final modeling can be expected to be less than 7 miles; therefore, FPC TX expects this preliminary BA analysis to be representative of the final analysis. FPC TX is in the process of finalizing the cultural resources assessment that will be provided to EPA for consultation with the State Historic Preservation Officer (SHPO).

Should you have any questions regarding this application, please contact Ms. Tammy Lasater of Formosa Plastics Corporation at tammyl@fdde.fpcusa.com, or 302-836-2241 or Ms. Karen Olson of Zephyr Environmental Corporation, at kolson@zephyrenv.com or 512-879-6618.

Sincerely,

Randy P. Smith
Vice President/General Manager

Enclosure

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Jeff Robinson
Chief, Air Permits Section
U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

EHS/tl

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X
☐ Agent
☐ Addressee

B. Received by *(Printed Name)*

C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
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☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number
(Transfer from service label)
7011 0110 0000 1782 9978

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

PLACE STICKER AT TOP OF ENVELOPE TO THE RIGHT OF THE RETURN ADDRESS, FOLD AT DOTTED LINE

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City, State, ZIP+4 *Dallas, Texas 75202-2733*

PS Form 3800, August 2006 See Reverse for Instructions

FORMOSA PLASTICS CORP., TEXAS
P.O. BOX 700
POINT COMFORT, TEXAS 77978
361/987-7000

To:

Mr. Jeff Robinson
Chief, Air Permits Section
U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

GREENHOUSE GAS PERMIT APPLICATION
PREVENTION OF SIGNIFICANT DETERIORATION: 2012 EXPANSION PROJECT
GAS TURBINES
POINT COMFORT, TEXAS

SUBMITTED TO:
ENVIRONMENTAL PROTECTION AGENCY
REGION VI
MULTIMEDIA PLANNING AND PERMITTING DIVISION
FOUNTAIN PLACE 12TH FLOOR, SUITE 1200
1445 ROSS AVENUE
DALLAS, TEXAS 75202-2733

SUBMITTED BY:

FORMOSA PLASTICS CORPORATION, TEXAS
P.O. BOX 700
POINT COMFORT, TEXAS 77978

PREPARED BY:
ZEPHYR ENVIRONMENTAL CORPORATION
2600 VIA FORTUNA, SUITE 450
AUSTIN, TEXAS 78746

NOVEMBER 2012

zephyr

TABLE OF CONTENTS

APPENDICES

1.0 INTRODUCTION

Formosa Plastics Corporation, Texas (FPC TX) currently operates a number of chemical plants at its chemical complex in Point Comfort, Calhoun County, Texas. FPC TX proposes to expand the chemical complex within the existing FPC TX Point Comfort site footprint. The 2012 Expansion Project will consist of a two new Combined Cycle Turbines (Gas Turbines), an Olefins Expansion (a new Olefins 3 plant and a Propane Dehydrogenation (PDH) unit), and a new Low Density Polyethylene (LDPE) Plant.

On June 3, 2010, the EPA published final rules for permitting sources of Greenhouse Gases (GHGs) under the prevention of significant deterioration (PSD) and Title V air permitting programs, known as the GHG Tailoring Rule.[1] After July 1, 2011, modified sources with GHG emission increases of more than 75,000 tons/yr on a carbon dioxide equivalent (CO_2e) basis at existing major sources are subject to GHG PSD review. On December 23, 2010, EPA issued a Federal Implementation Plan (FIP) authorizing EPA to issue PSD permits in Texas for GHG sources until Texas submits the required SIP revision for GHG permitting and it is approved by EPA.[2]

The FPC TX Point Comfort 2012 Expansion Project (which includes the Olefins 3 Plant and PDH Unit, LDPE plant, and two combined cycle combustion turbines) triggers PSD review for GHG pollutants because the GHG emissions from the expansion project will be more than 75,000 tons/yr and the site is an existing major source. Therefore, the entire 2012 Expansion Project is subject to PSD review for GHG pollutants. The applications for GHG PSD air permits for this expansion are being submitted to the EPA. The applications for criteria pollutant PSD permits are being submitted to the Texas Commission on Environmental Quality (TCEQ) with copies for the EPA.

As described in the July 13, 2012 Kelly Hart & Hallman memo to Mr. Brian Tomasovic of EPA (found in Appendix D of this application), the 2012 Expansion Project consists of the three new related plants (identified above) which comprise a single GHG PSD project. In order to align

[1] 75 FR 31514 (June 3, 2010).
[2] 75 FR 81874 (Dec. 29, 2010).

FPC TX organizational responsibility and accountability for compliance with future permit requirements related to these plants, FPC TX is requesting a separate permit for each proposed new plant. Therefore, three separate permit applications are being submitted. Even though three separate applications are being submitted, FPC TX will perform and satisfy PSD permitting requirements, including ambient air quality impacts analysis, in aggregate for all the expansion project plants.

FPC TX is hereby submitting this application for a GHG Prevention of Significant Deterioration (PSD) air quality permit for the gas turbines at FPC TX's Point Comfort, Texas complex. The GHG emission unit descriptions, GHG emissions calculations and a GHG Best Available Control Technology (BACT) analysis are provided for those gas turbine GHG emission sources.

2.0 GENERAL APPLICATION INFORMATION

A completed TCEQ Form PI-1 is included in this application to provide all the general administrative and project information for this GHG application. In addition, an overall expansion plot plan, plot plan of the gas turbine (cogeneration) area, and area map are included in this section.

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment
For EPA GHG Permit Application

Important Note: The agency **requires** that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued *and* no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: Formosa Plastics Corporation, Texas		
Texas Secretary of State Charter/Registration Number (*if applicable*): 5107506		
B. Company Official Contact Name: Randy Smith, Vice President		
Title: General Manager		
Mailing Address: P.O. Box 700		
City: Point Comfort	State: Texas	ZIP Code: 77978
Telephone No.: 361-987-7000	Fax No.: 361-987-2363	E-mail Address:
C. Technical Contact Name: Tammy G. Lasater		
Title: EHS Department Staff		
Company Name: Formosa Plastics Corporation, Texas		
Mailing Address: P.O. Box 320		
City: Delaware City	State: Delaware	ZIP Code: 19706
Telephone No.: 302-836-2241	Fax No.: 302-836-2239	E-mail Address: TammyL@fdde.fpcusa.com
D. Site Name: Formosa Plastics Corporation, Texas		
E. Area Name/Type of Facility:2012 Expansion Project: Utilities –Two Gas Turbines	☒ Permanent ☐ Portable	
F. Principal Company Product or Business: Petrochemical Manufacturing Facility		
Principal Standard Industrial Classification Code (SIC): 2821		
Principal North American Industry Classification System (NAICS): 325211		
G. Projected Start of Construction Date: 2013		
Projected Start of Operation Date: 2016		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 201 Formosa Drive		
City/Town: Point Comfort	County: Calhoun	ZIP Code: 77978
Latitude (nearest second): 28° 41′ 20″	Longitude (nearest second): 096° 32′ 50″	

Texas Commission on Environmental Quality
Form PI-1 General Application for
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I. Applicant Information (continued)	
I. Account Identification Number (leave blank if new site or facility): CB0038Q	
J. Core Data Form.	
Is the Core Data Form (Form 10400) attached? If *No*, provide customer reference number and regulated entity number (complete K and L).	☐ YES ☒ NO
K. Customer Reference Number (CN): CN600130017	
L. Regulated Entity Number (RN): RN100218973	
II. General Information	
A. Is confidential information submitted with this application? If *Yes*, mark each **confidential** page **confidential** in large red letters at the bottom of each page.	☐ YES ☒ NO
B. Is this application in response to an investigation or enforcement action? If *Yes*, attach a copy of any correspondence from the agency.	☐ YES ☒ NO
C. Number of New Jobs: 225	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
Senator: Glenn Hegar	District No.: 18
Representative: Todd Hunter	District No.: 32
III. Type of Permit Action Requested	
A. Mark the appropriate box indicating what type of action is requested. Initial ☐ Amendment ☒ Revision (30 TAC 116.116(e)) ☐ Change of Location ☐ Relocation ☐	
B. Permit Number (if existing): 19166, PSD-TX-760M8	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* Construction ☒ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Prevention of Significant Deterioration ☒ Hazardous Air Pollutant Major Source ☐ Plant-Wide Applicability Limit ☐ Other:____________________	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

III. Type of Permit Action Requested (continued)		
E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.		☐ YES ☒ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If *No*, attach detailed information.		☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?		☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.		
List: None		
G. Are you permitting planned maintenance, startup, and shutdown emissions? If *Yes*, attach information on any changes to emissions under this application as specified in VII and VIII.		☒ YES ☐ NO
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability)		
Is this facility located at a site required to obtain a federal operating permit? If *Yes*, list all associated permit number(s), attach pages as needed).		☒ YES ☐ NO ☐ To be determined
Associated Permit No (s.): SOP 01951		
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved. FOP Significant Revision ☒ FOP Minor ☐ Application for an FOP Revision ☐ To Be Determined ☐ Operational Flexibility/Off-Permit Notification ☐ Streamlined Revision for GOP ☐ None ☐		

III. Type of Permit Action Requested (continued)	
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. (check all that apply)	
GOP Issued ☐	GOP application/revision application submitted or under APD review ☐
SOP Issued ☒	SOP application/revision application submitted or under APD review ☐
IV. Public Notice Applicability	
A. Is this a new permit application or a change of location application?	☐ YES ☒ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☒ YES ☐ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☐ YES ☒ NO
If *Yes*, list the affected state(s) and/or Class I Area(s).	
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.	
1. Is there any change in character of emissions in this application?	☐ YES ☒ NO
2. Is there a new air contaminant in this application?	☐ YES ☒ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☒ NO
F. List the total annual emission increases associated with the application (*list* **all** *that apply and attach additional sheets as needed*):	
Greenhouse Gases – see permit application emission summary	

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment
For EPA GHG Permit Application

V. Public Notice Information (complete if applicable)			
A. Public Notice Contact Name: Tammy G Lasater			
Title: Corporate Air Permitting Manager			
Mailing Address: P.O. Box 320			
City: Delaware City	State: DE	ZIP Code: 19706	
Telephone No.: (302) 836-2241			
B. Name of the Public Place: Calhoun County Branch Library & Point Comfort City Hall			
Physical Address (No P.O. Boxes): 1 Lamar Street and 102 Jones Street			
City: Point Comfort	County: Calhoun	ZIP Code: 77978	
The public place has granted authorization to place the application for public viewing and copying.			☒ YES ☐ NO
The public place has internet access available for the public. Yes, Library No, City Hall			☒ YES ☒ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits			
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.			
The Honorable:			
Mailing Address:			
City:	State:	ZIP Code:	
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? *(For Concrete Batch Plants)*			☐ YES ☐ NO
Presiding Officers Name(s):			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	
3. Provide the name, mailing address of the chief executive of the city for the location where the facility is or will be located.			
Chief Executive:			
Mailing Address:			
City:	State:	ZIP Code:	

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment
For EPA GHG Permit Application

V. Public Notice Information (complete if applicable) (continued)	
3. Provide the name, mailing address of the Indian Governing Body for the location where the facility is or will be located. *(continued)*	
Name of the Indian Governing Body: N/A	
Title:	
Mailing Address:	
City:	State: / ZIP Code:
D. Bilingual Notice	
Is a bilingual program **required** by the Texas Education Code in the School District?	☒ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?	☒ YES ☐ NO
If *Yes*, list which languages are required by the bilingual program? Spanish	
VI. Small Business Classification (Required)	
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?	☐ YES ☒ NO
B. Is the site a major stationary source for federal air quality permitting?	☒ YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?	☒ YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?	☒ YES ☐ NO
VII. Technical Information	
A. The following information must be submitted with your Form PI-1 (this is just a checklist to make sure you have included everything)	
1. Current Area Map ☒	
2. Plot Plan ☒	
3. Existing Authorizations ☒	
4. Process Flow Diagram ☒	
5. Process Description ☒	
6. Maximum Emissions Data and Calculations ☒	
7. Air Permit Application Tables ☐	
a. Table 1(a) (Form 10153) entitled, Emission Point Summary ☐	
b. Table 2 (Form 10155) entitled, Material Balance ☐	
c. Other equipment, process or control device tables ☐	

VII. Technical Information	
B. Are any schools located within 3,000 feet of this facility?	☐ YES ☒ NO
C. Maximum Operating Schedule:	
Hours: 24 / Day(s): 7 / Week(s): 52 / Year(s):	
Seasonal Operation? If Yes, please describe in the space provide below.	☐ YES ☒ NO
D. Have the planned MSS emissions been previously submitted as part of an emissions inventory?	☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.	
E. Does this application involve any air contaminants for which a *disaster review* is required?	☐ YES ☒ NO
F. Does this application include a pollutant of concern on the *Air Pollutant Watch List (APWL)*?	☐ YES ☒ NO
VIII. State Regulatory Requirements **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment**. *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*	
A. Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?	☒ YES ☐ NO
B. Will emissions of significant air contaminants from the facility be measured?	☒ YES ☐ NO
C. Is the Best Available Control Technology (BACT) demonstration attached?	☒ YES ☐ NO
D. Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?	☒ YES ☐ NO
IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
A. Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?	☒ YES ☐ NO
B. Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?	☐ YES ☐ NO
C. Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO

IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** ***The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.***	
D. Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E. Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F. Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G. Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X. Professional Engineer (P.E.) Seal	
Is the estimated capital cost of the project greater than $2 million dollars?	☒ YES ☐ NO
If *Yes*, submit the application under the seal of a Texas licensed P.E.	
XI. Permit Fee Information	
Check, Money Order, Transaction Number ,ePay Voucher Number:	Fee Amount: N/A
Company name on check: Formosa Plastics Corporation	Paid online?: ☐ YES ☐ NO
Is a copy of the check or money order attached to the original submittal of this application?	☐ YES ☐ NO ☒ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☐ YES ☐ NO ☒ N/A

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment
For EPA GHG Permit Application

TCEQ

XII. Delinquent Fees and Penalties

This form **will not be processed** until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.

XIII. Signature

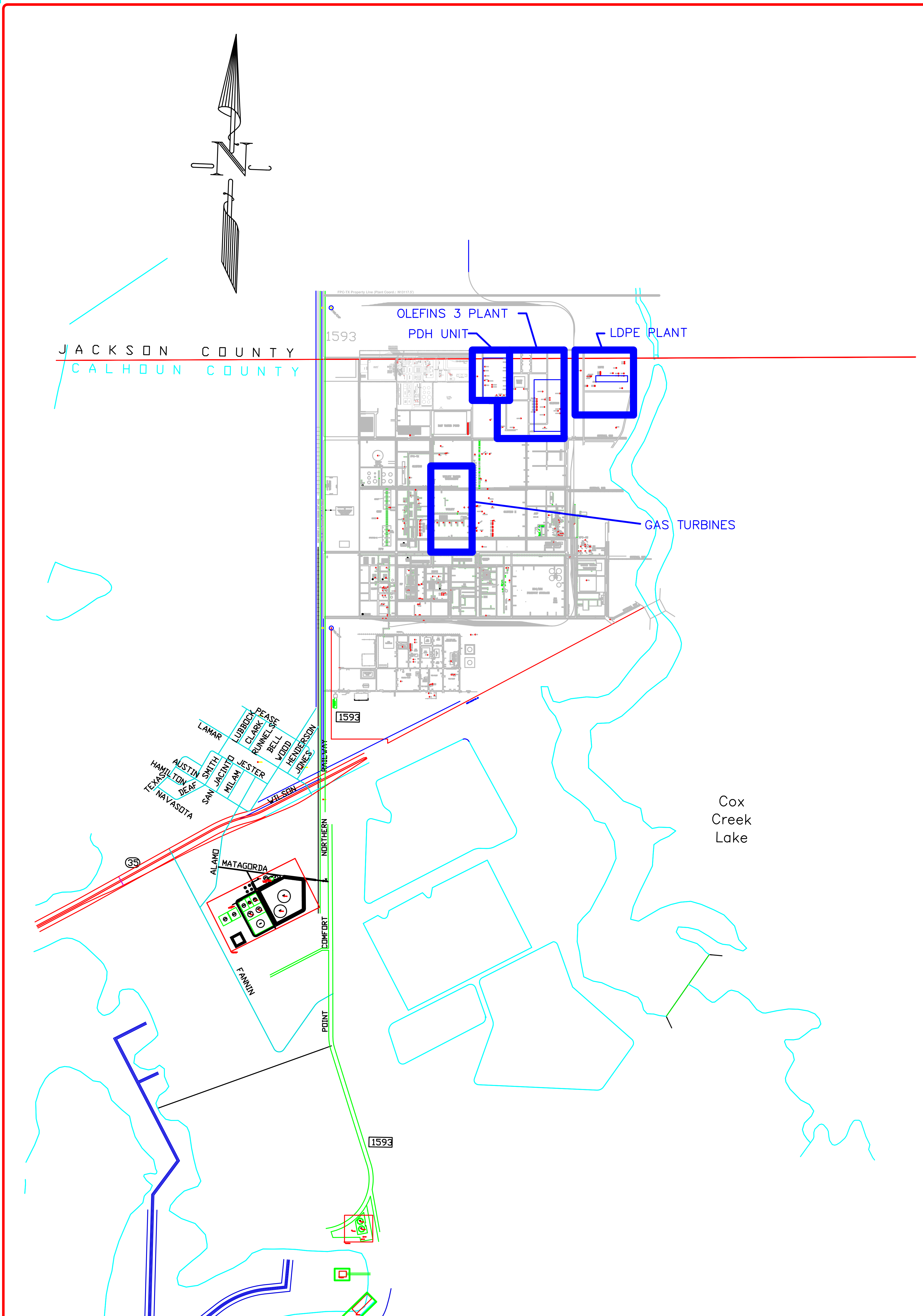
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.

Name: R. P. Smith, Vice President/General Manager

Signature: ______________________

Original Signature Required

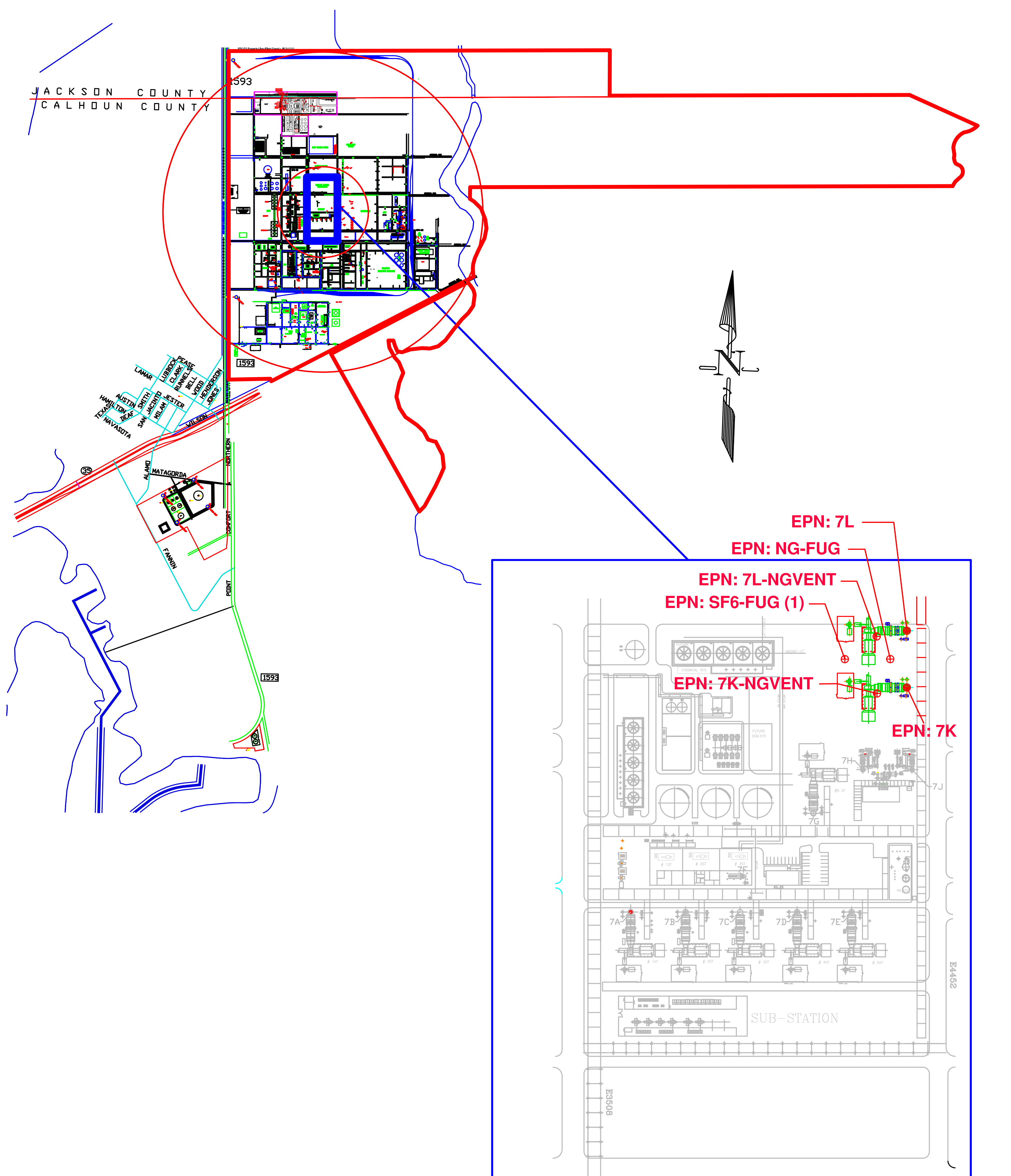
Date: 11/27/12



Formosa Plastics®

DESCRIPTION: OVERALL VIEW SHEET LAYOUT		PROJECT: Overall Plot Plan	SHEET 1 OF 1
DRAWN BY: DWD	SCALE: 1" = 1000'	REFERENCE FILES	
CHECKED BY: G.A.G.	DATE: 8/01/95	CLIENT: FORMOSA PLASTICS CORP.	
APPROVED BY: G.A.G.	JOB NO. PC95-042		

Permit\Plot Plans\FPC-TX Overall OL III_PDH_LDPE 10.10.12.dwg



UTILITIES PLANT - COGENERATION AREA

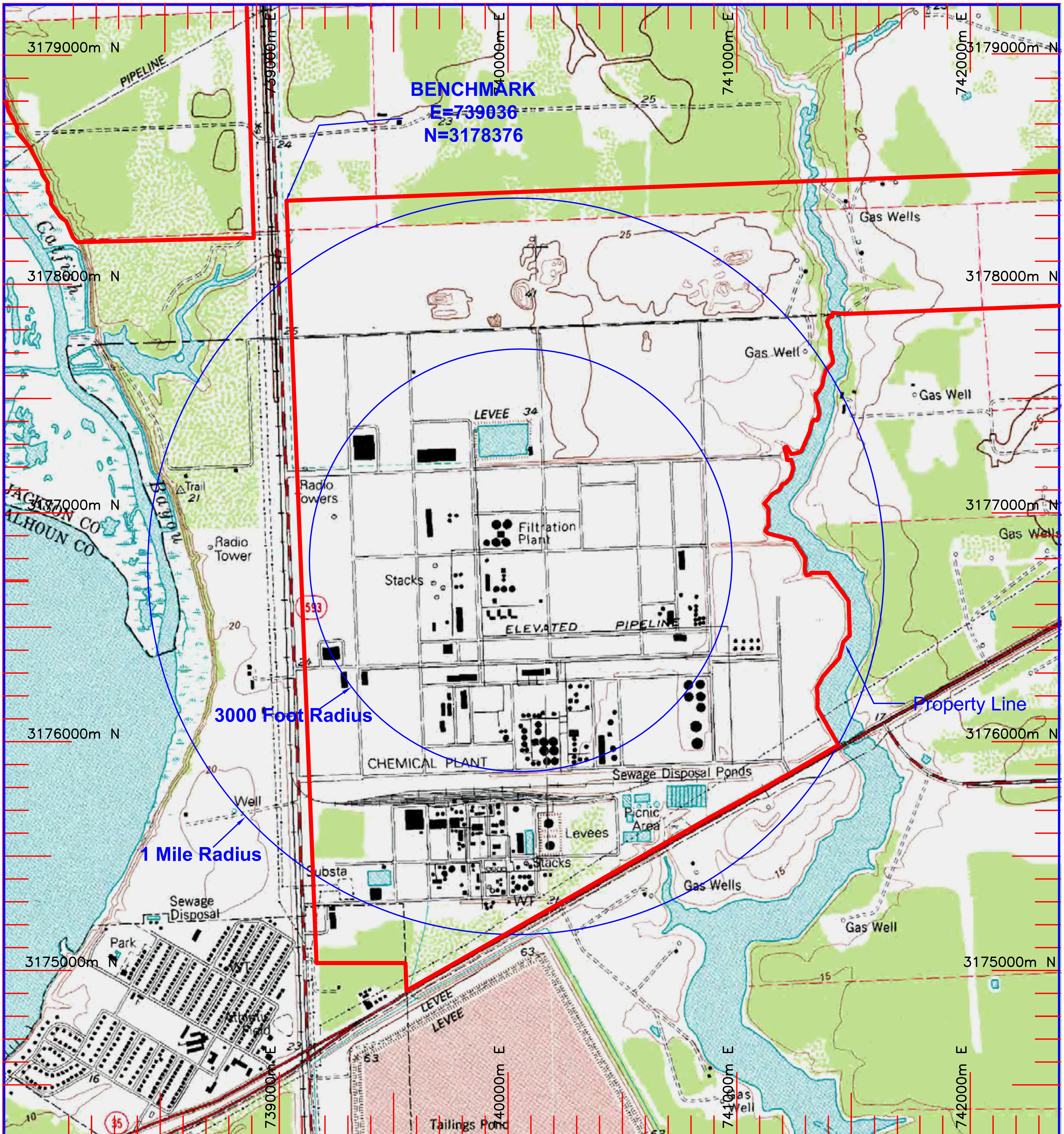
Note: (1) Location of SF6-FUG is approximate at this time.

Formosa Plastics

OVERALL VIEW
SHEET LAYOUT

Overall Plot Plan
Utilities Plant – New Gas Turbines

SHEET 1 OF 1



SCALE 1:24,000

0 1/2 1 MILE

0 1000 2000 3000 4000 5000 FEET

0 .5 1 KILOMETER

CONTOUR INTERVAL 5 FEET
COORDINATE DATUM: NAD83
U.S.G.S. 7.5 MINUTE SERIES (TOPOGRAPHIC)
POINT COMFORT, TEXAS QUADRANGLE 1995

QUADRANGLE LOCATION

zephyr

AREA MAP

FORMOSA PLASTICS CORPORATION, TEXAS

2012 Expansion Project

Designed by:		Filename:	Date:
E. Quiat		areamap.dwg	10/24/12

3.0 PROCESS DESCRIPTION AND GHG EMISSION SOURCES

3.1 PROCESS DESCRIPTION

With this application, FPC TX is seeking authorization to construct two new combined cycle turbines at its existing plant, in Calhoun County, Texas. Both combustion turbines will be GE Model 7EA units with heat recovery steam generators (HRSGs). The combustion turbines have a nominal output of 80 megawatts each and the HRSGs have a nominal steam output of 360,000 lb/hr with duct firing. Steam from the HRSGs will be routed to the existing utility plant steam header to combine with steam produced by the existing utility plant. Steam is routed from the steam header to the three existing steam turbines for electricity generation.

The gas combustion turbines will be fired with sweet pipeline quality natural gas only. The HRSG will have the capability of firing fuel from three separate fuel sources. The first is sweet pipeline quality natural gas, the second is a pure hydrogen stream (from an existing process unit) and the third is tail gas from the Olefins plants (primarily methane and hydrogen), referred to as "OL tail gas".

The following are the GHG emission sources related to the power generating equipment.

- EPNs 7K, 7L - GE 7EA natural gas-fired combustion turbines
- EPNs 7K, 7L - HRSG duct burner fuel combustion (natural gas and OL tail gas)
- EPN NG-FUG- Natural gas piping and metering
- EPN SF6-FUG - Electrical equipment insulated with sulfur hexafluoride (SF_6)
- EPNs 7K-NGVENT, 7L-NGVENT - Turbine startup natural gas purges

A process flow diagram is included at the end of this section.

3.2 GHG EMISSION SOURCES

3.2.1 Combustion Turbine Generators

The plant will consist of two identical sweet pipeline quality natural gas-fired GE model 7EA combustion turbine generators (CTGs) with a nominal output of 80 megawatts each. Each combustion turbine will exhaust to a heat recovery steam generator, or HRSG, with duct firing capabilities. Emission point numbers (EPNs) for the combustion turbine/HRSG units are identified as 7K and 7L.

The combustion turbine burns sweet pipeline quality natural gas to generate electricity. The main components of a CTG consist of a compressor, combustor, turbine, and generator. The compressor pressurizes ambient air and discharges it into the combustor section where the fuel is mixed with the compressed air and combusted. Hot exhaust gases then enter the turbine section where the gases expand across the turbine blades which rotate a shaft to power an electric generator. The exhaust gas exiting each combustion turbine will be routed to a HRSG for steam production.

3.2.2 Heat Recovery Steam Generators

Heat recovered in each HRSG will be utilized to produce steam. Steam generated within the HRSG will be discharged to the existing steam manifold that supplies three existing steam turbine generators. Steam from the manifold may also be used as utility steam for various plant uses. Each HRSG will be equipped with duct burners for supplemental heat input for steam production. The duct burners will have the capability of firing fuel from three different sources. These fuels are sweet pipeline-quality natural gas, a pure hydrogen stream (from another process unit) and a hydrogen/methane mixture (Olefins unit “OL” tail gas). It should be noted that combustion of the pure hydrogen fuel stream does not produce emissions of GHGs as this stream does not contain carbon.

Each HRSG’s duct burners will have a maximum heat input capacity of 120 MMBtu/hr per unit and normal duct burner operation will vary from 0 to 100 percent of the maximum capacity. The duct burners will be located in the HRSG prior to the selective catalytic reduction (SCR) system. The exhaust gases from the unit, which includes emissions from the CT and the duct burners, will pass through the SCR and exit the stack to the atmosphere (EPNs: 7K, 7L).

3.2.3 Natural Gas and OL Tail Gas Piping

Natural gas is delivered to the site via pipeline. Natural gas will be metered and piped to the combustion turbines and HRSGs; OL tail gas will also be piped to the HRSGs. Project fugitive GHG emissions from the gas piping components associated with the combustion units will include emissions of methane (CH_4) and carbon dioxide (CO_2). Emissions from the natural gas and OL tail gas piping are designated as EPN: NG-FUG.

3.2.4 Electrical Equipment Insulated with Sulfur Hexafluoride (SF_6)

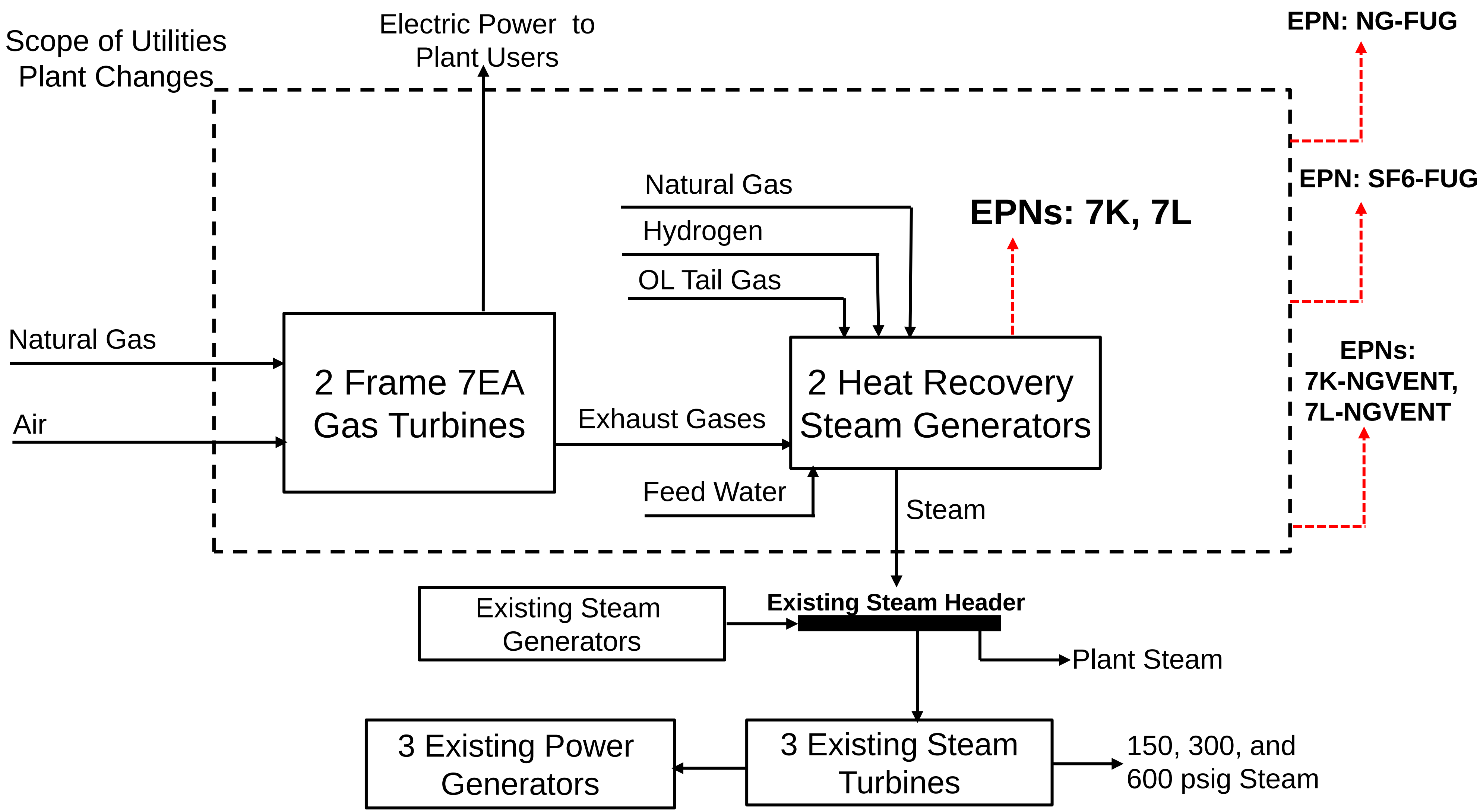
The two circuit breakers associated with the proposed combustion turbine units will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable, and non-toxic synthetic gas. It is a fluorinated compound that has an extremely stable molecular structure. The unique chemical properties of SF_6 make it an efficient electrical insulator. The gas is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. SF_6 is only used in sealed and safe systems which under normal circumstances do not leak gas. The capacity of each of the circuit breakers (two total) associated with the proposed plant is currently estimated to be 248 lbs. of SF_6 (496 lbs in both breakers).

The proposed circuit breakers at the generator output will have a low pressure alarm and a low pressure lockout. The alarm will alert operating personnel of any leakage in the system and the lockout prevents any operation of the breaker due to lack of “quenching and cooling” SF_6 gas. Emissions from the SF_6-insulated circuit breakers are designated as EPN: SF6-FUG.

3.2.5 Turbine Startup Natural Gas Purges

During the startup sequence for each gas turbine, a portion of the natural gas supply line is purged through a separate purge vent stack. The purge results in GHG emissions of methane and CO_2 from natural gas (EPNs: 7K-NGVENT, 7L-NGVENT).

Utilities Plant – Two New Combined-Cycle Gas Turbine Units
Process Flow Diagram



4.0 GHG EMISSION CALCULATIONS

This section provides a description of the methods used to estimate GHG emissions from the proposed combined cycle turbine GHG emission units. GHG emissions were estimated using the most appropriate unit-specific emission calculation methodologies available in EPA's GHG Mandatory Reporting Rule (GHG MRR), 40 CFR 98.

The following provides an explanation of calculation methodologies by source type. A summary of GHG emissions, detailed emission calculations and supporting information can be found in Appendix A.

4.1 GHG EMISSIONS FROM NATURAL GAS COMBUSTION SOURCES

GHG emission calculations for the natural gas-fired combustion units are calculated in accordance with the procedures in the Mandatory Greenhouse Reporting Rules, Subpart C – Stationary Fuel Combustion Sources.[3]

$$CO_2 = 1\ x\ 10^{-3} x\ Fuel\ x\ HHV\ X\ EF \quad \textbf{(EQ. C-1)}$$

Where:

CO_2 = Annual CO_2 mass emissions for the specific fuel type, metric tons/yr

Fuel = Volume of fuel combusted per year, standard cubic feet/yr, based on the maximum rated equipment capacity and maximum hours of operation (8,760 hours/yr)

EF = Emission factor for natural gas from table C-1

HHV = default high heat value of fuel, from table C-1

0.001 = conversion from kg to metric tons

Emissions of CH_4 and nitrous oxide (N_2O) are calculated using the emission factors (kg/MMBtu) for natural gas combustion from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[4]

[3] 40 C.F.R. 98, Subpart C – *General Stationary Fuel Combustion Sources*

The global warming potential factors used to calculate carbon dioxide equivalent (CO_2e) emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.

4.2 GHG EMISSIONS FROM OL TAIL GAS COMBUSTION SOURCES

GHG emission calculations for the OL tail gas-firing in the duct burners are calculated in accordance with the procedures in the Mandatory Greenhouse Reporting Rules, Subpart C – Stationary Fuel Combustion Sources.[5]

$$CO_2 = \frac{44}{12} \times Fuel\ x\ CC\ X\ \frac{MW}{MVC} \times 0.001 \quad \text{(EQ. C-5)}$$

Where:

CO_2 = Annual CO_2 mass emissions for the specific fuel type, metric tons/yr

Fuel = Volume of fuel combusted per year, standard cubic feet/yr, based on the maximum rated equipment capacity and maximum hours of operation (8,760 hours/yr)

CC = Annual average carbon content of fuel (kg C per scf), obtained from the estimated fuel gas composition using an engineering estimate

MW = Annual average molecular weight of fuel (kg/kg-mol), obtained from the estimated fuel gas composition using an engineering estimate

MVC = molar volume conversion factor = 849.5 scf/kg-mol @ std. conditions

0.001 = conversion from kg to metric tons

In accordance with the Tier 3 fuel calculation methodology in 40 CFR 98, Subpart C, emissions of CH_4 and nitrous oxide (N_2O) are calculated using the emission factors (kg/MMBtu) for natural gas combustion from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules[6] and

[4] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 CFR 98, Subpart C, Table C-2

[5] 40 C.F.R. 98, Subpart C – *General Stationary Fuel Combustion Sources*

[6] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 CFR 98, Subpart C, Table C-2

annual heat release for fuel gas combustion. The global warming potential factors used to calculate carbon dioxide equivalent (CO_2e) emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.

4.3 GHG EMISSIONS FROM ELECTRICAL EQUIPMENT INSULATED WITH SF_6

Even though SF_6 emissions from the circuit breakers associated with the proposed units are not expected, potential emissions were calculated using a conservative SF_6 annual leak rate of 0.5% by weight (of total charge) and the SF_6 capacity for both breakers. The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[7]

4.4 GHG EMISSIONS FROM NATURAL GAS/OL TAIL GAS PIPING FUGITIVES AND FUEL LINE MAINTENANCE AND TURBINE STARTUP RELEASES

GHG emission calculations for natural gas and OL tail gas piping component fugitive emissions are based on emission factors from Table W-1A of the Mandatory Greenhouse Gas Reporting Rules.[8] The concentrations of CH_4 and CO_2 in the natural gas are based on a typical natural gas analysis. Since the CH_4 and CO_2 content of OL tail gas is variable, the concentrations of CH_4 and CO_2 from the typical natural gas analysis are used as a worst-case estimate. Although audio/visual/olfactory (AVO) inspections are being proposed as BACT for this source (see Section 6.4.5) no control efficiency credits were taken for AVO monitoring. The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.[9]

GHG emission calculations for releases of natural gas related to combustion unit startup/shutdowns are calculated using the same CH_4 and CO_2 concentrations as natural gas

[7] *Global Warming Potentials*, 40 CFR Part 98, Subpart A, Table A-1.

[8] *Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production*, 40 CFR Part 98, Subpart W, Table. W-1A.

[9] *Global Warming Potentials*, 40 CFR Part 98, Subpart A, Table A-1.

and OL tail gas piping fugitives and the volume and initial temperature and pressure of gas prior to venting.

5.0 PREVENTION OF SIGNIFICANT DETERIORATION APPLICABILITY

Since the Point Comfort expansion project[10] emissions increase of GHG is greater than 75,000 ton/yr. of CO_2e, PSD is triggered for GHG emissions. The emissions netting analysis for all 2012 Expansion Project GHG emissions sources is documented on the attached TCEQ PSD netting tables: Table 1F and Table 2F found in Appendix B. Note that the 2012 Expansion Project emission sources associated with the two combined cycle turbines are new and, as such, there are no contemporaneous emission changes associated with these emission units. There are however, a few existing emission sources (Olefins II pyrolysis fuel oil and pyrolysis gasoline storage tanks) impacted by the Olefins Expansion portion of the 2012 Expansion Project. The contemporaneous emission rates for these sources are listed in Table 2F.

Please note that, although separate permits are being requested and three separate permit applications have been submitted, the project increase shown here represents emissions from all three permits and the total project increase.

[10] Includes emission sources from Olefins 3 plant, LDPE plant and combined cycle turbines.

6.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

The PSD rules define BACT as:

> *Best available control technology* means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under [the] Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.[11]

In the EPA guidance document titled *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA recommended the use of the Agency's five-step "top-down" BACT process to determine BACT for GHGs.[12] In brief, the top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to

[11] 40 C.F.R. § 52.21(b)(12.)

[12] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, p. 18 (Nov. 2010).

the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT.

EPA has divided this analytical process into the following five steps:

Step 1: Identify all available control technologies.
Step 2: Eliminate technically infeasible options.
Step 3: Rank remaining control technologies.
Step 4: Evaluate most effective controls and document results.
Step 5: Select the BACT.

This evaluation is generally performed individually for each GHG emission source which are addressed in subsections 6.2 onward. One control technology, Carbon Capture and Sequestration (CCS), could be a potential control technology for multiple emissions sources associated with the 2012 Expansion Project. Therefore, before presenting the BACT evaluation for the individual gas turbine GHG emission sources, the first subsection 6.1, will present the BACT evaluation for CCS as a potential control technology.

6.1 BACT FOR CARBON CAPTURE AND SEQUESTRATION

FPC TX addresses the potential to capture GHG emissions that are emitted from Carbon Capture and Sequestration (CCS) candidate sources associated with the 2012 Expansion Project listed below (plant names in parenthesis):

- 9 cracking furnaces (Olefins Expansion)
- 4 PDH reactors (Olefins Expansion)
- 4 steam boilers (Olefins Expansion)
- 2 combined cycle gas-fired turbines (Gas Turbines)
- 2 regenerative thermal oxidizers (LDPE)

The EPA five step top down BACT evaluation for this potential control technology options is provided in Appendix C. As shown in that analysis, CCS is not only not commercially available, not technically feasible but also economically unreasonable. Therefore, it is not included as a BACT option for any of the emissions sources associated with the 2012 Expansion Project.

6.2 BACT FOR THE COMBINED CYCLE COMBUSTION TURBINES

6.2.1 Step 1: Identify All Available Control Technologies

6.2.1.1 Inherently Lower-Emitting Processes/Practices/Designs

A summary of available, lower greenhouse gas emitting processes, practices, and designs for combustion turbine power generators is presented below.

Combustion Turbine Energy Efficiency Processes, Practices, and Designs

Combustion Turbine Design

CO_2 is a product of combustion of fuel containing carbon, which is inherent in any power generation technology using fossil fuel. It is not possible to reduce the amount of CO_2 generated from combustion, as CO_2 is the essential product of the chemical reaction between the fuel and the oxygen in which it burns, not a byproduct caused by imperfect combustion. As such, there is no technology available that can effectively reduce CO_2 generation by adjusting the conditions in which combustion takes place.

The only effective means to reduce the amount of CO_2 generated by a fuel-burning power plant is to generate as much electric power as possible from the combustion, thereby reducing the amount of fuel needed to meet the plant's required power output. This result is obtained by using the most efficient generating technologies available, so that as much of the energy content of the fuel as possible goes into generating power.

The most efficient way to generate electricity from a natural gas fuel source is the use of a combined cycle turbine design, as is proposed. For comparison sake, fossil fuel technologies' efficiency ranges from approximately 30-50% (higher heating value [HHV]). A modern natural gas fired combined cycle unit operating under optimal conditions has a base load efficiency of approximately 50% (HHV). Based on this information, it is clear that the proposed facilities provide the most efficient option for electric generation.

Combined cycle units operate based on a combination of two thermodynamic cycles: the Brayton and the Rankine cycles. A combustion turbine operates on the Brayton cycle and the HRSG and steam turbine operate on the Rankine cycle. The combination of the two thermodynamic cycles allows for the high efficiency associated with combined cycle plants.

The following discussion lists those design elements and operating and maintenance practices that have been considered and selected to maximize energy efficiency. These individual elements are not being individually considered as BACT control options, rather overall unit energy-efficient design and operation is considered the BACT option. The individual elements' effects on overall unit energy efficiency are reflected in the proposed holistic energy efficiency-based BACT limit in Step 5.

Periodic Burner Tuning

The GE Model 7EA combustion turbines have regularly scheduled maintenance programs. These maintenance programs are important for the reliable operation of the unit, as well as to maintain optimal efficiency. As the combustion turbine is operated, the unit experiences degradation and loss in performance. The combustion turbine maintenance program helps restore the recoverable lost performance. The maintenance program schedule is determined by the number of hours of operation and/or turbine starts. There are three basic maintenance levels, commonly referred to as combustion inspections, hot gas path inspections, and major overhauls. Combustion inspections are the most frequent of the maintenance cycles. As part of this maintenance activity, the combustors are tuned to restore highly efficient low-emission operation.

Instrumentation and Controls

The GE Model 7EA combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system is a digital-type and is supplied with the combustion turbine. The distributed control system (DCS) controls all aspects of the turbine's operation, including the fuel feed and burner operations. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency low-emission performance for full-load and part-load conditions.

Heat Recovery Steam Generator Energy Efficiency Processes, Practices, and Designs

The HRSGs recover the energy from combustion turbine exhaust waste heat to convert boiler feed water to steam. In order to convert the recovered energy to electricity, additional natural gas, hydrogen, or OL tail gas is burned in the duct burners which increases the temperature of the exhaust coming from the combustion turbines and thereby creates additional steam for the steam turbine for electricity production. The duct burner firing provides additional power generation capacity during periods of high electrical demand. By firing hydrogen or OL tail gas in the duct burners, FPC TX will be recovering heating value from these process streams that are normally vented or flared, thereby reducing GHG emissions from flaring.

The GE Model 7EA combustion turbine-based combined cycle HRSG is generally a horizontal, natural circulation, drum-type heat exchanger designed with two pressure levels of steam generation, split superheater sections with interstage attemperation, and post-combustion emissions control equipment. The HRSG is designed to maximize the conversion of the combustion turbine exhaust gas waste heat to steam for all plant ambient and load conditions. Maximizing steam generation will increase the steam turbine's power generation, which maximizes plant efficiency.

Heat Exchanger Design Considerations

HRSGs are heat exchangers designed to capture as much thermal energy as possible from the combustion turbine exhaust gases. This is performed at multiple pressure levels. For a drum-type configuration, each pressure level incorporates an economizer section(s) and evaporator section. These heat transfer sections are made up of many thin-walled tubes to provide surface area to maximize the transfer of heat to the working fluid. Most of the tubes also include extended surfaces (e.g., fins). The extended surface optimizes the heat transfer, while minimizing the overall size of the HRSG. Additionally, flow guides are used to distribute the flow evenly through the HRSG to allow for efficient use of the heat transfer surfaces and post-combustion emissions control components.

Insulation

HRSGs take waste heat from the combustion turbine exhaust gas and uses that waste heat to convert boiler feed water to steam. As such, the temperatures inside the HRSG are nearly equivalent to the exhaust gas temperatures of the turbine. For the GE Model 7EA combustion turbines, these temperatures can approach 1,000°F. HRSGs are designed to maximize the conversion of the waste heat to steam. One aspect of the HRSG design in maximizing this waste heat conversion is the use of insulation. Insulation minimizes heat loss to the surrounding air, thereby improving the overall efficiency of the HRSG. Insulation is applied to the HRSG panels that make up the shell of the unit, to the high-temperature steam and water lines, and typically to the bottom portion of the stack.

Minimizing Fouling of Heat Exchange Surfaces

HRSGs are made up of a number of tubes within the shell of the unit that are used to generate steam from the combustion turbine exhaust gas waste heat. To maximize this heat transfer, the tubes and their extended surfaces need to be as clean as possible. Fouling of the tube surfaces impedes the transfer of heat. Fouling occurs from the constituents within the exhaust gas stream. To minimize fouling, filtration of the inlet air to the combustion turbine is performed. By reducing the fouling, the efficiency of the unit is maintained.

Minimizing Vented Steam and Repair of Steam Leaks

As with all steam-generated power facilities, minimization of steam vents and repair of steam leaks is important in maintaining the plant's efficiency. A combined cycle facility has just a few locations where steam is vented from the system, including at the deaerator vents, blowdown tank vents, and vacuum pumps/steam jet air ejectors. These vents are necessary to improve the overall heat transfer within the HRSG by removing solids and air that potentially blankets the heat transfer surfaces lowering the equipment's performance. Additionally, power plant operators are concerned with overall efficiency of their facilities. Therefore, steam leaks are repaired as soon as possible to maintain facility performance. Minimization of vented steam and repair of steam leaks will be performed for this project.

Energy Efficiency Processes, Practices, and Designs

There are a number of other components within the combined cycle plant that help improve overall efficiency, including:

- **Fuel gas superheating** – The overall efficiency of the combustion turbine is increased with increased fuel inlet temperatures. The natural gas will be superheated with steam at the existing fuel gas conditioning skid. This improves the efficiency of the combustion turbine.
- **Multiple combustion turbine/HRSG trains** – Multiple combustion turbine/HRSG trains help with part-load operation. The multiple trains allow the unit to achieve higher overall plant part-load efficiency by shutting down a train operating at less efficient part-load conditions and ramping up the remaining train to high-efficiency full-load operation.

6.2.2 Step 3: Rank Remaining Control Technologies

As documented above, implementation of CCS technology is currently infeasible, leaving energy efficiency measures as the only technically feasible emission control options. As all of the energy efficiency related processes, practices, and designs discussed in the previous section of this application are being proposed for this project, a ranking of the control technologies is not necessary for this application.

6.2.3 Step 4: Evaluate Most Effective Controls and Document Results

As all of the energy efficiency related processes, practices, and designs discussed in the previous section of this application are being proposed for this project, an examination of the energy, environmental, and economic impacts of the efficiency designs is not necessary for this application.

6.2.4 Step 5: Select BACT

FPC TX proposes the selection of all available energy-efficient design options and operational/maintenance practices presented in Step 1 as BACT:

- Use of Combined Cycle Power Generation Technology
- Combustion Turbine Energy Efficiency Processes, Practices, and Designs, including some of the following:
    - Efficient turbine design
    - Periodic turbine burner tuning
    - Instrumentation and controls
- HRSG Energy Efficiency Processes, Practices, and Designs
    - Efficient heat exchanger design, including recovering heating value from process streams by duct burner firing (hydrogen or OL tail gas)
    - Insulation of HRSG
    - Minimizing fouling of heat exchange surfaces
    - Minimizing vented steam and repair of steam leaks
- Energy Efficiency Processes, Practices, and Designs
    - Fuel gas superheating
    - Multiple combustion turbine/HRSG trains

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, FPC TX is proposing a BACT limit for each combined cycle unit which takes into consideration the operation, variability and interaction of all these energy efficient 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 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.

FPC TX is proposing a 365-day rolling average net heat rate for the Project of 11,650 Btu/kWh (HHV, gross), with duct burner firing, for each combined cycle unit. This heat rate limit is equivalent to an output based GHG BACT limit of 0.568 ton CO_2e/MWhr (gross). Since the plant heat rate varies according to turbine operating load and the amount of duct burner firing, FPC TX proposes to demonstrate compliance with the 11,650 Btu/kWh (HHV) heat rate on a rolling 365-day average basis.

To determine this proposed numeric output-based BACT limit, FPC TX started with the turbine's design heat rate for combined cycle operation (gross, HHV basis) with duct firing and then calculated a compliance margin based upon reasonable degradation factors that may foreseeably reduce efficiency under real-world conditions. The design heat rate for the gas combustion turbines is approximately 12,100 BTU/kWh (HHV, gross basis) based on manufacturer information with a rating of 80 MW per turbine.

Since existing steam turbines will be used to convert HRSG steam into electrical energy, FPC TX is proposing a combined cycle design heat rate that considers the steam generated in each HRSG (up to 360,000 lb/hr with duct firing) in addition to the 80 MW of electricity generated by each gas turbine. Using a steam turbine generator conversion rate of 14.11 klbs steam per MWh[13], the equivalent combined cycle design heat rate for each unit is 10,330 Btu/kWhr (HHV, gross) with duct firing on a 365-day rolling average basis. Note that this rate reflects the facility's "gross" power production, meaning the denominator is the total amount of energy produced by the unit (turbine electrical production plus HRSG steam production) prior to accounting for auxiliary load consumed by operation of the unit.

To determine an appropriate heat rate BACT limit for the permit compliance margins are added to the base heat rate limit. Firstly, a 3.3% design margin reflecting the possibility that the constructed facility will not be able to achieve the design heat rate was considered. Design and construction of a combined-cycle power plant involves many assumptions about anticipated performance of the many elements of the plant, which are often imprecise or not reflective of conditions once installed at the site. As a consequence, the facility calculates an "Installed

[13] This steam turbine conversion rate is based on historical annual average performance data for the existing steam turbines at the Point Comfort Utility plant. This is not intended to be a permit limit or enforceable representation. Rather, this value was selected to convert HRSG steam production to an electrical equivalent for purposes of developing a unit equivalent combined cycle heat rate.

Base Heat Rate", which represents a design margin of 3.3% to address such items as equipment underperformance and short-term degradation.

Secondly, to establish an enforceable BACT condition that can be achieved over the life of the facility, the permit limit must also account for anticipated degradation of the equipment over time between regular maintenance cycles. The manufacturer's degradation curves project anticipated degradation rate of 5% within the first 48,000 hours of the gas turbine's useful life; they do not reflect any potential increase in this rate, which might be expected after the first major overhaul and/or as the equipment approaches the end of its useful life. Further, the projected 5% degradation rate represents the average, and not the maximum or guaranteed, rate of degradation for the gas turbines. Therefore, FPC TX proposes that, for purposes of deriving an enforceable BACT limitation on the proposed facility's heat rate, gas turbine degradation may reasonably be estimated at 6% of the facility's heat rate.

Finally, in addition to the heat rate degradation from normal wear and tear on the combustion turbines, FPC TX is also providing a reasonable compliance margin based on potential degradation in other elements of the combined cycle plant that would cause the overall plant heat rate to rise (*i.e.*, cause efficiency to fall). Degradation in the performance of the heat recovery steam generator, heat transfer and ancillary equipment such as pumps and motors is also expected to occur over the course of a major maintenance cycle.

FPC TX performed a search of the EPA's RACT/BACT/LAER Clearinghouse for natural gas fired combustion turbine generators and found no entries which address BACT for GHG emissions. FPC TX also reviewed pending GHG applications and permits issued by EPA Region 6 for combined cycle gas turbines.

Several EPA Region 6 permit applications and issued permits included GE combined cycle Frame 7FA turbines, a larger unit by comparison, and were new power generation plants which included a new, high-efficiency steam turbine as part of the project scope. For example, the Calpine Channel Energy Center Draft GHG Permit includes a new combined cycle gas turbine unit that is sized significantly larger than FPC TX's proposed units. As a result, Calpine's proposed unit has a notably smaller heat rate and output-based BACT limit.

One application, the Air Liquide Large Industries permit application submitted on September 13, 2012, includes several new combined cycle units that feature GE Frame 7EA gas turbines. In proposing a BACT heat rate limit, Air Liquide calculates an overall unit heat rate using a steam turbine conversion rate of 9.1 lbs steam per kWh, which is notably different that the conversion rate for FPC TX's existing steam turbines, based on historical operating data. FPC TX does not believe it is appropriate to compare heat rate limits for other proposed new combined cycle units that will use new steam turbines with the FPC TX's proposed new units (which will route steam to an existing steam header and steam turbines).

After accounting for these compliance margins, FPC TX calculated the proposed heat rate limit of 11,650 (Btu/kWh, gross, HHV basis, rolling 365-day average) based on the base heat rate. The calculation of the heat rate and the equivalent ton CO_2e/MWhr is provided in Appendix A of this application.

FPC TX noted that its proposed BACT measures for the gas turbines are similar to those found in other GHG permit applications; however, the numeric output-based BACT limit is notably different for a few reasons. First, the size of turbine proposed with this project (e.g., GE Frame 7EA) is significantly smaller than those proposed in other GHG applications (i.e., GE Frame 7FA). Second, the HRSG steam conversion rate (based on existing steam turbines) is lower than that of a new combined cycle unit or new steam turbine generator.

6.3 BACT FOR SF_6 INSULATED ELECTRICAL EQUIPMENT

6.3.1 Step 1: Identify All Available Control Technologies

Step 1 of the Top-Down BACT analysis is to identify all feasible control technologies. One technology is the use of state-of-the-art SF_6 technology with leak detection to limit fugitive emissions. In comparison to older SF_6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning a fraction of the SF_6 has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

One alternative considered in this analysis is to substitute another, non-GHG substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 were addressed in the National Institute of Standards and Technology (NTIS) Technical Note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6.*[14]

6.3.2 Step 2: Eliminate Technically Infeasible Options

According to the report NTIS Technical Note 1425, SF_6 is a superior dielectric gas for nearly all high voltage applications.[15] It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF_6-insulated equipment. The report concluded that although "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture… it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Therefore there are currently no technically feasible options besides use of SF_6.

6.3.3 Step 3: Rank Remaining Control Technologies

The use of state-of-the-art SF_6 technology with leak detection to limit fugitive emissions is the highest ranked control technology that is technically feasible for this application.

[14] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6,* NIST Technical Note 1425, Nov.1997.
[15] *Id.* at 28 – 29.

6.3.4 Step 4: Evaluate Most Effective Controls and Document Results

Energy, environmental, or economic impacts were not addressed in this analysis because the use of alternative, non-greenhouse-gas substance for SF_6 as the dielectric material in the breakers is not technically feasible.

6.3.5 Step 5: Select BACT

Based on this top-down analysis, FPC TX concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection would be the BACT control technology option. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers.[16] The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. This alarm will function as an early leak detector that will bring potential fugitive SF_6 emissions problems to light before a substantial portion of the SF_6 escapes. The lockout prevents any operation of the breaker due to lack of "quenching and cooling" SF_6 gas.

6.4 BACT FOR NATURAL GAS AND OL TAIL GAS PIPING FUGITIVES

6.4.1 Step 1: Identify All Available Control Technologies

The following available control technologies for fugitive piping components emitting GHGs (those in natural gas and fuel gas service) were identified:

- Installation of leakless technology components to eliminate fugitive emission sources.
- Implementing LDAR programs (those used for VOC components) in accordance with applicable state and federal air regulations.
- Implement alternative monitoring using a remote sensing technology such as infrared camera monitoring.

[16] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current*.

- Implementing an audio/visual/olfactory (AVO) monitoring program typically used for non-VOC compounds.

6.4.2 Step 2: Eliminate Technically Infeasible Options

All the available options are considered technically feasible and have been used in industry as described below.

Leakless valves are primarily used where highly toxic or otherwise hazardous materials are present. Leakless valves are expensive in comparison to a standard (non-leakless) valve. These technologies are generally considered cost prohibitive except for specialized service.

LDAR programs are typically implemented for control of VOC emissions from materials in VOC service (at least 5 wt% VOC), however instrument monitoring may also be technically feasible for components in CH4 service, including the fuel gas and natural gas piping fugitives.

Remote sensing technologies have been proven effective in leak detection and repair, especially on larger pipeline-sized lines. The use of sensitive infrared camera technology has become widely accepted as a cost-effective means for identifying leaks of hydrocarbons depending on the number of sources.

AVO monitoring methods are also capable of detecting leaks from piping components as leaks can be detected by sound (audio) and sight. AVO programs are commonly used in industry and technically feasible for the GHG fugitives in the Olefins 3 unit.

6.4.3 Step 3: Rank Remaining Control Technologies

AVO monitoring has been implemented historically at the Point Comfort plant. AVO monitoring is as effective in detecting significant leaks as Method 21 instrument or remote sensing monitoring if AVO inspections are performed frequently enough. AVO detections can be performed very frequently, at lower cost and with less additional manpower and equipment than

Method 21 instrument or remote sensing monitoring because it does not require a specialized piece of monitoring equipment. Therefore, for components in methane (natural gas or fuel gas) service AVO is considered the most preferred technically feasible alternative.

Remote sensing using infrared imaging has accepted by EPA as an acceptable alternative to Method 21 instrument monitoring and leak detection effectiveness is expected to comparable. However, less manpower may be required for remote sensing compared to Method 21 depending on the number of sources. The frequency of monitoring is more limited than AVO because the number of simultaneous measurements will be limited by the availability of the remote sensing equipment.

Method 21 Instrument monitoring has historically been used to identify leaks in need of repair. However, instrument monitoring requires significant allocation of manpower as compared to AVO monitoring, while AVO is expected to be equally effective at identifying significant leaks.

Leakless technologies are effective in eliminating fugitive emissions from the locations where installed. However, because of their high cost, these specialty components are, in practice, selectively applied only as absolutely necessary to toxic or hazardous components.

6.4.4 Step 4: Evaluate Most Effective Controls and Document Results

The AVO monitoring option is expected to be effective in finding leaks, can be implemented at the greatest frequency and lower cost due to being incorporated into routine operations.

The use of Method 21 instrument leak detection is technically feasible, however the leak effectiveness, in comparison to AVO monitoring, is likely similar or less for components in methane service. However, Method 21 instrument monitoring is much more costly and requires much more manpower than AVO monitoring. In addition, AVO monitoring can be done at a much greater frequency thus allowing detection of leaks more quickly.

Remote sensing monitoring costs less than Method 21 instrument monitoring but is still much more costly than AVO. Typically, remote sensing is more applicable to larger potential emission sources that contain critical fugitive components with the potential for high volume leaks. In addition, remote sensing can be performed on a limited frequency because it requires specialized equipment. Remote sensing is not practicable for small fugitive sources

Leakless technologies have not been universally adopted as BACT for emission from fugitive piping components, even for hazardous services. Therefore, FPC TX believes that these technologies are not practical for control of GHG emissions from methane piping components.

6.4.5 Step 5: Select BACT

Please note the total GHG fugitive emissions are expected to be less than 0.05% of the total GHG emissions from the proposed new combined cycle turbines. FPC TX proposes to perform weekly AVO monitoring of piping components associated with the new combined cycle turbines that are in GHG service (natural gas and fuel gas service).

FPC TX performed a search of the EPA's RACT/BACT/LAER Clearinghouse for piping fugitive GHG emissions and found no entries which address BACT for GHG emissions. Although not listed in the RACT/BACT/LAER Clearinghouse, a GHG BACT analysis was performed by other GHG permit applications submitted to EPA Region 6. A discussion of FPC TX's proposed BACT as compared to those projects is provided below.

- **Equistar Channelview – Olefins I&II Expansions**
    - The Equistar applications request authorization of GHG emissions from piping components. These applications propose remote sensing of "pipeline sized" components that are not otherwise subject to Method 21 monitoring.
- **Equistar La Porte – Olefins Expansion**
    - The Equistar permit application proposes to employ TCEQ's 28 LAER fugitive leak detection and repair program for components "in CH4 service" as BACT, however "in CH4 service" is not defined in the application.

- **Chevron Phillips Chemical Company LP – Cedar Bayou Plant, New Ethylene Unit**
  - The Chevron Phillips application proposes as-observed AVO (audio/visual/olfactory) monitoring for natural gas and fuel gas piping components as BACT.
- **ExxonMobil Baytown Olefins Plant**
  - The ExxonMobil application proposes as-observed AVO (audio/visual/olfactory) monitoring for natural gas piping components and applicable TCEQ LDAR programs for components in VOC service as BACT.
- **ExxonMobil Mont Belvieu Plastics Plant**
  - The ExxonMobil application proposes as-observed AVO (audio/visual/olfactory) monitoring for natural gas piping components and applicable TCEQ LDAR programs for components in VOC service as BACT.
- **INEOS USA LLC – Olefins Expansion**
  - The INEOS permit requires TCEQ's 28VHP LDAR program for all methane piping components.
- **BASF FINA - NAFTA Region Olefins Complex**
  - The BASF permit specifies the use of TCEQ's 28LAER LDAR program for all fugitive emissions of methane.

FPC TX's proposed weekly AVO monitoring is equally as effective and can be performed at greater frequency as instrument monitoring. Therefore, FPC TX's proposed BACT for fugitive components is as effective as BACT proposed in other applications.

6.5 BACT FOR NATURAL GAS VENTING

6.5.1 Step 1: Identify All Available Control Technologies

No physical GHG control technologies exist for natural gas venting from maintenance startup and shutdown activities. The primary means of limiting/controlling GHG emissions from this activity, is minimizing the frequency. FPC TX expects to operate the turbines with as much on-stream time as possible, thus minimizing the frequency of startups and associated natural gas purges during startup.

6.5.2 Step 2: Eliminate Technically Infeasible Options

No options are being eliminated in this step.

6.5.3 Step 3: Rank Remaining Control Technologies

No options are being eliminated in this step.

6.5.4 Step 4: Evaluate Most Effective Controls and Document Results

No options are being eliminated in this step.

6.5.5 Step 5: Select BACT

FPC TX proposes to minimize the annual frequency of natural gas venting to no more than the frequencies specified as the bases for the emission calculations (Appendix A) for this activity: 15 turbine startup purges per year per turbine.

7.0 OTHER PSD REQUIREMENTS

7.1 IMPACTS ANALYSIS

An impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> *Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause or contribute to a violation of the NAAQS are not applicable to GHGs. Therefore, there is no requirement to conduct dispersion modeling or ambient monitoring for CO_2 or GHGs.*[17]

An impacts analysis for non-GHG emissions is being submitted with the State/PSD/Non-attainment application submitted to the TCEQ.

7.2 GHG PRECONSTRUCTION MONITORING

A pre-construction monitoring analysis for GHG is not being provided with this application in accordance with EPA's recommendations:

> *EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs.*[18]

[17] EPA, *PSD and Title V Permitting Guidance For Greenhouse Gases* at 48-49.
[18] *Id.* at 49.

A pre-construction monitoring analysis for non-GHG emissions is being submitted with the State/PSD/Nonattainment application submitted to the TCEQ.

7.3 ADDITIONAL IMPACTS ANALYSIS

A PSD additional impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> *Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions 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 with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, 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.*[19]

A PSD additional impacts analysis for non-GHG emissions is being submitted with the State/PSD/Nonattainment application submitted to the TCEQ.

[19] *Id.*

8.0 PROPOSED GHG MONITORING PROVISIONS

FPC TX proposes to monitor CO_2 emissions by monitoring the quantity of fuels combusted in the turbines and heat recovery steam generators and performing periodic fuel sampling as required by the applicable provisions of 40 CFR 98 Subpart C as discussed in Section 4. FPC TX expects that this approach will allow for monitoring of GHG emissions in a manner consistent with existing plant operating procedures and the GHG monitoring and reporting requirements applicable to both existing sources and those sources proposed with this application.

APPENDIX A

GHG EMISSION CALCULATIONS

BACT Calculation of Heat Rate Limit
Formosa Plastic Corporation, Texas
2012 Expansion Project: Gas Turbines
November 2012

Unit:	**GE 7EA Gas Turbine**	**HRSG with 100% Duct Firing**	
Heat Input:	970	120	**MMBtu/hr (HHV)**
Energy Output (Gross):	80,000	25,521	**kW (Gross)**
Total Base Heat Rate, Combined Cycle Unit (Gross):	**10,330**		**Btu/kWh (HHV) (Gross)**
	3.3%		**Design Margin**
	6.0%		**Performance Margin**
	3.0%		**Degradation Margin**
Calculated Base Heat Rate with Compliance Margins:	**11,650**		**Btu/kWh (HHV) (Gross)**

Calculation of ton CO2e/MWhr Heat Rate Limit for Each combined cycle unit

EPNs	Total Energy Output (each unit) (MW)	GHG Emission Rate (each unit) [1] (ton CO2e/yr)	GHG Emission Rate (each unit) [2] (ton CO2e/hr)	ton CO_2e/MWhr (gross) [3]
7K, 7L	105.5	525,024	59.9	**0.568**

Notes:

[1] From CO2 Summary Sheet, combined cycle unit subtotal divided by two (two units).

[2] Based on 8760 hours per year operation.

[3] Calculated as GHG emission rate (ton CO2e/hr) divided by Total energy output (MW)

Table A-1
GHG Emission Summary
Formosa Plastic Corporation, Texas
2012 Expansion Project: Gas Turbines
November 2012

Source Name	Operating Scenario	EPN	Detailed Calculations in	GHG Mass Emissions (tpy)	CO_2e (tpy)
Gas Turbine 1	Firing 100% Natural Gas	7K	Table A-2	463,071	463,516
Gas Turbine 2		7L		463,071	463,516
Duct Firing, Unit 1 [1]	Firing 100% Natural Gas	7K	Table A-3	61,449	61,508
	Firing 100% OL Tail Gas		Table A-4	52,975	53,034
	Firing 100% Hydrogen [2]		N/A	0	0
Duct Firing, Unit 2 [1]	Firing 100% Natural Gas	7L	Table A-3	61,449	61,508
	Firing 100% OL Tail Gas		Table A-4	52,975	53,034
	Firing 100% Hydrogen [2]		N/A	0	0
Subtotal Total, Combined Cycle Units [3] =				**1,049,040**	**1,050,047**
Turbine Startup, Fuel Line Maintenance	Startup, Maintenance	7K-NGVENT, 7L-NGVENT	Table A-5	1.24	25.1
Fugitive Components	N/A	NG-FUG	Table A-6	20.90	425.2
SF_6 Electrical Insulation	N/A	SF6-FUG	Table A-7	<0.01	29.6
Total =				**1,049,062**	**1,050,527**

Notes:

[1] The duct burners may fire up to 100% heat input on any listed fuel or any combination thereof.

[2] Combustion of 100% hydrogen fuel stream in the duct burners does not result in any GHG emissions (carbon content is zero).

[3] Total GHG emissions are calculated as the maximum emissions from duct burner firing on any one of the three fuel types, plus GHG emission contributions from the Gas turbines.

Table A-2
GHG Emission Calculations - Natural Gas Combustion - Gas Turbines
Formosa Plastic Corporation, Texas
2012 Expansion Project: Gas Turbines
November 2012

GHG Emissions Contribution From Natural Gas Fired Combustion Turbines:

EPN	Average Heat Input (MMBtu/hr)	Annual Heat Input (MMBtu/yr)	Pollutant	Emission Factor (kg/MMBtu)[1]	GHG Mass Emissions[2] (tpy)	Global Warming Potential[3]	CO_2e (tpy)
7K	997	8,733,720	CO_2	53.02	463,062	1	463,062
			CH_4	1.0E-03	8.73	21	183.4
			N_2O	1.0E-04	0.87	310	270.7
				Totals	**463,071**		**463,516**
7L	997	8,733,720	CO_2	53.02	463,062	1	463,062
			CH_4	1.0E-03	8.73	21	183.4
			N_2O	1.0E-04	0.87	310	270.7
				Totals	**463,071**		**463,516**
Total for 2 Turbines					***926,143***		***927,032***

Notes:

1. CO_2 GHG factor from Table C-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting (GHG MRR).

CH_4 and N_2O GHG factors based on Table C-2 of GHG MRR.

2. CO_2 emissions based on 40 CFR Part 98, Subpart C, Equation C-1.

3. Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

Sample Calculation, CO_2:

GHG Mass Emissions (metric ton/yr) = 0.001 x 8733720 (MMBtu/yr) x 53.02 kg/MMBtu = 463062

CO2e (metric ton/yr) = 463062 (tpy) x 1 = 463062

Table A-3
GHG Emission Calculations - Duct Burners Natural Gas Combustion
Formosa Plastic Corporation, Texas
2012 Expansion Project: Gas Turbines
November 2012

GHG Emissions Contribution From Natural Gas Fired Combustion:

Source Type	Average Heat Input/Unit (MMBtu/hr)	Annual Avg Heat Input, Each Unit (MMBtu/yr)	Pollutant	Emission Factor (kg/MMBtu)[1]	Emissions per Unit: GHG Mass Emissions[2] (metric ton/yr)	Emissions per Unit: Global Warming Potential[3]	Emissions per Unit: CO_2e (metric ton/yr)	Emissions per Unit: CO_2e (tpy)
Turbine 1 Duct Burners	120	1,051,200	CO_2	53.02	55,735	1	55,735	61,447
			CH_4	1.0E-03	1.05	21	22.1	24.3
			N_2O	1.0E-04	0.11	310	32.6	35.9
				Totals	**55,736**		**55,789**	**61,508**
Turbine 2 Duct Burners	120	1,051,200	CO_2	53.02	55,735	1	55,735	61,447
			CH_4	1.0E-03	1.05	21	22.1	24.3
			N_2O	1.0E-04	0.11	310	32.6	35.9
				Totals	**55,736**		**55,789**	**61,508**
Total, All Natural Gas Duct Firing					***111,472***		***111,579***	***123,015***

Notes:

1. CO2 GHG factor from Table C-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting (GHG MRR).
CH4 and N2O GHG factors based on Table C-2 of GHG MRR.
2. CO_2 emissions based on 40 CFR Part 98, Subpart C, Equation C-1.
3. Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

Sample Calculation, CO_2:

GHG Mass Emissions (metric ton/yr) = 0.001 x 1051200 (MMBtu/yr) x 53.02 kg/MMBtu = 55735
CO2e (metric ton/yr) = 55735 (metric ton/yr) x 1 = 55734.6

Table A-4
GHG Emission Calculations - OL Tail Gas Combustion
Formosa Plastic Corporation, Texas
2012 Expansion Project: Gas Turbines
November 2012

Olefins (OL) Tail Gas Data:

Variable	Value	Units	Reference
Net Heating Value (LHV)	625	Btu/scf	Formosa Design Specification
Carbon Content (Annual Avg)	0.677	kg C/kg	Formosa Design Specification
Molecular Weight (Annual Avg)	9.8	kg/kg-mol	Formosa Design Specification

GHG Emissions Contribution from OL Tail Gas Combustion:

Source Type	Average Heat Input/Unit (MMBtu/hr)	Annual Average Fuel Gas Usage/Unit[1] (MMscf/hr)	Annual Average Fuel Use, Each Unit (scf/yr)	Annual Average Heat Input, Each Unit (MMBtu/yr)	Pollutant	Emission Factor (kg/MMBtu)[2]	GHG Mass Emissions[3] (metric ton/yr)	Global Warming Potential[4]	CO_2e (metric ton/yr)	CO_2e (tpy)
Turbine 1 Duct Burners	120	0.192	1.68E+09	1.05E+06	CO_2		48,049	1	48,049	52,974
					CH_4	1.0E-03	1.05	21	22.08	24
					N_2O	1.0E-04	0.11	310	32.59	36
						Totals	**48,050**		**48,103**	**53,034**
Turbine 2 Duct Burners	120	0.192	1.68E+09	1.05E+06	CO_2		48,049	1	48,049	52,974
					CH_4	1.0E-03	1.05	21	22.08	24
					N_2O	1.0E-04	0.11	310	32.59	36
						Totals	**48,050**		**48,103**	**53,034**
Total, All OL Tail Gas Combustion							***96,099***		***96,206***	***106,068***

Notes:

1. Fuel use calculated as: MMscf/hr = Firing rate (MMBtu/hr) / HHV (Btu/scf)

2. CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

CH_4 and N_2O emissions based on 40 CFR Part 98, Subpart C, Equation C-8.

3. CO_2 emissions based on 40 CFR Part 98, Subpart C, Equation C-5.

4. Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

Sample Calculation: Duct Burners Turbine 1 - CO_2:

GHG Mass Emissions (metric ton/yr) = (44/12) x 1.68E+09 (scf/yr) x 0.677 kg C/kg x 9.77 kg/kg-mol / 849.5 scf/kg-mole @ std cond. x 0.001 = 4.80E+04

CO2e (metric ton/yr) = 4.80E+04 (metric ton/yr) x 1 = 4.80E+04

Table A-5

GHG Emission Calculations -

Gaseous Fuel Venting During Turbine Startup and

Fuel Line Maintenance, EPNs 7K-NGVENT, 7L-NGVENT

Formosa Plastic Corporation, Texas

2012 Expansion Project: Gas Turbines

November 2012

Location	Initial Conditions			Final Conditions			Annual Frequency of Event	CO_2[3]	CH_4[4]	Total, both Turbines
	Volume[1] (ft^3)	Press. (psig)	Temp. (°F)	Press. (psig)	Temp. (°F)	Volume[2] (scf)		Annual (tpy)	Annual (tpy)	Annual (tpy)
Turbine Startup	75.0	300	90	0	68	1,635	30	0.0336	0.98	
Fuel Line Maintenance	20.0	300	90	0	68	436	24	0.00718	0.210	
GHG Mass-Based Emissions								0.0408	1.19	1.24
Global Warming Potential[5]								1	21	
CO_2e Emissions								0.0408	25.1	25.1

Notes:

1. *Initial volume is calculated by multpilying the crossectional area by the length of pipe using the following formula:* V_i = pi * [(diameter in inches/12)/2]^2 * length in feet = ft^3
2. *Final volume calculated using ideal gas law* $[(PV/ZT)_i = (PV/ZT)_f]$. $V_f = V_i\ (P_i/P_f)\ (T_f/T_i)\ (Z_f/Z_i)$, *where Z is estimated using the following equation:* $Z = 0.9994 - 0.0002P + 3E\text{-}08P^2$.
3. CO_2 *emissions based on vol% of* CO_2 *in natural gas* — *1.20% from natural gas analysis*
4. CH_4 *emissions based on vol% of* CH_4 *in natural gas* — *96.6% from natural gas analysis*
5. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Example calculation:

1635 scf Nat Gas	*0.012 scf CO2*	*lbmole*	*44 lb* CO_2	*ton =*	=	*0.0336*	*ton/yr* CO_2
yr	*scf Nat Gas*	*385 scf*	*lbmole*	*2000 lb*			

Table A-6
GHG Emission Calculations - Fugitive Component Emissions
Formosa Plastic Corporation, Texas
2012 Expansion Project: Gas Turbines
November 2012

GHG Emissions Contribution From Fugitive Piping Components:

EPN	Source Type	Fluid State	Count	Emission Factor[1] scf/hr/comp	CO_2 Content (vol %)	CH_4 Content (vol %)	CO_2 (tpy)	Methane (tpy)	Total (tpy)
NG-FUG	Valves	Gas/Vapor	600	0.121	1.20%	96.6%	0.436	12.80	
	Flanges	Gas/Vapor	2400	0.017			0.245	7.19	
	Relief Valves	Gas/Vapor	5	0.193			5.80E-03	1.70E-01	
	Sampling Connections	Gas/Vapor	10	0.031			1.86E-03	5.46E-02	
	Compressors	Gas/Vapor	3	0.002			3.60E-05	1.06E-03	
GHG Mass-Based Emissions							0.689	20.2	***20.9***
Global Warming Potential[2]							1	21	
CO_2e Emissions							0.69	424.5	***425.2***

Notes:

1. Emission factors from Table W-1A of 40 CFR 98 Mandatory Greenhouse Gas Reporting

2. Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

Example calculation:

600 valves	0.121 scf gas	0.012 scf CO2	lbmol	44.01 lb CO_2	8760 hr	ton	0.44	ton/yr
	hr * valve	scf gas	385 scf	lbmol	yr	2000 lb		

Table A-7

GHG Emission Calculations - Electrical Equipment Insulated with SF_6

Formosa Plastic Corporation, Texas

2012 Expansion Project: Gas Turbines

November 2012

EPN	Insulated SF_6 Circuit Breaker Capacity (pounds)	Annual Leak Rate, wt %	Annual Leak Rate (tpy)	Global Warming Potential[1]	Estimated Annual CO_2e Emission Rate (tpy)
SF6-FUG	495	0.50%	1.24E-03	23,900	29.6

Notes:

1. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

APPENDIX B

PSD NETTING TABLES

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.:	TBD	Application Submittal Date:	
Company	Formosa Plastic Corporation, Texas		
RN:	RN100218973	Facility Location:	201 Formosa Drive
City	Point Comfort	County:	Calhoun
Permit Unit I.D.:	2012 Expansion Project	Permit Name:	TBD
Permit Activity:	☐ New Major Source	☑ Modification	
Project or Process Description:	Olefins Expansion, LDPE Plant and Gas Turbines		

Complete for all pollutants with a project emission increase.	**POLLUTANTS**						
	Ozone		**CO**	**SO_2**	**PM**	**GHG**	**CO_2e**
	NOx	**VOC**					
Nonattainment? (yes or no)						No	No
Existing site PTE (tpy)	**This form for GHG only**					>100,000	>100,000
Proposed project increases (tpy from 2F)						3,034,027	3,990,283
Is the existing site a major source? 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
If netting required, estimated start of construction:		9/1/13					
5 years prior to start of construction:		9/1/08	Contemporaneous				
estimated start of operation:		10/1/15	Period				
Net contemporaneous change, including proposed project, from Table 3F (tpy)						3,034,027	3,990,283
FNSR applicable? (yes or no)						Yes	Yes

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]: GHG Mass Emissions		**Permit:** TBD	
Baseline Period:	N/A	**to**	N/A

Affected or Modified Facilities[2]	FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions[5]	Projected Actual Emissions	Difference (B - A) [6]	Correction [7]	Project Increase[8]
Olefins 3 Plant Sources										
1	OL3-FUR1	OL3-FUR1		0.00	0.00	99,732		99,732		99,732
2	OL3-FUR2	OL3-FUR2		0.00	0.00	99,732		99,732		99,732
3	OL3-FUR3	OL3-FUR3		0.00	0.00	99,732		99,732		99,732
4	OL3-FUR4	OL3-FUR4		0.00	0.00	99,732		99,732		99,732
5	OL3-FUR5	OL3-FUR5		0.00	0.00	99,732		99,732		99,732
6	OL3-FUR6	OL3-FUR6		0.00	0.00	99,732		99,732		99,732
7	OL3-FUR7	OL3-FUR7		0.00	0.00	99,732		99,732		99,732
8	OL3-FUR8	OL3-FUR8		0.00	0.00	99,732		99,732		99,732
9	OL3-FUR9	OL3-FUR9		0.00	0.00	99,732		99,732		99,732
10	OL3-BOIL1	OL3-BOIL1		0.00	0.00	164,532		164,532		164,532
11	OL3-BOIL2	OL3-BOIL2		0.00	0.00	164,532		164,532		164,532
12	OL3-BOIL3	OL3-BOIL3		0.00	0.00	164,532		164,532		164,532
13	OL3-BOIL4	OL3-BOIL4		0.00	0.00	164,532		164,532		164,532
14	PDH-REAC1	PDH-REAC1		0.00	0.00	61,185		61,185		61,185
15	PDH-REAC2	PDH-REAC2		0.00	0.00	61,185		61,185		61,185
16	PDH-REAC3	PDH-REAC3		0.00	0.00	61,185		61,185		61,185
17	PDH-REAC4	PDH-REAC4		0.00	0.00	61,185		61,185		61,185
18	OL3-FUG	OL3-FUG		0.00	0.00	3.91		3.91		3.91
19	PDH-FUG	PDH-FUG		0.00	0.00	0.94		0.94		0.94

Pollutant[1]:	GHG Mass Emissions	**Permit:**	TBD
Baseline Period:	N/A	**to**	N/A

					A	**B**				
Affected or Modified Facilities[2]			**Permit No.**	**Actual Emissions[3]**	**Baseline Emissions[4]**	**Proposed Emissions[5]**	**Projected Actual Emissions**	**Difference (B - A)[6]**	**Correction[7]**	**Project Increase[8]**
	FIN	**EPN**								
20	OL3-FLR	OL3-FLR		0.00	0.00	118,050	see Note 1	118,050		118,050
21	OL3-LPFLR1	OL3-LPFLR1		0.00	0.00	985.6		985.6		985.6
22	OL3-LPFLR2	OL3-LPFLR2		0.00	0.00	985.6		985.6		985.6
23	OL3-DK1	OL3-DK1		0.00	0.00	211.6		211.6		211.6
24	OL3-DK2	OL3-DK2		0.00	0.00					
25	OL3-MAPD	OL3-MAPD		0.00	0.00	20.9		20.9		20.9
26	PDH-MSSVO	PDH-MSSVO		0.00	0.00	2.55		2.55		2.55
27	OL3-MSSVO	OL3-MSSVO		0.00	0.00	1.70		1.70		1.70
28	OL3-GEN	OL3-GEN		0.00	0.00	447		447		447
29	PDH-GEN	PDH-GEN		0.00	0.00	447		447		447
30	N6460FA/B	1087	19168	2.33	2.33	2.82	see Note 2	0.49		0.49
LDPE Plant Sources										
31	LD-022A/B	LD-022A/B		0.00	0.00	31,550		31,550		31,550
32	LD-023A/B	LD-023A/B		0.00	0.00					
33	OL3-FLR	OL3-FLR		0.00	0.00	21,933	see Note 1	21,933		21,933
34	LD-014	LD-014		0.00	0.00	4,818		4,818		4,818
35	LD-015	LD-015		0.00	0.00	4,818		4,818		4,818
36	LD-002	LD-002		0.00	0.00	207.1		207.1		207.1
37	NG-FUG	NG-FUG		0.00	0.00	20.9		20.9		20.9
38	LD-MSS	LD-MSS		0.00	0.00	0.01		0.01		0.01
Combined Cycle Turbine Sources										
39	7K	7K		0.00	0.00	524,520		524,520		524,520
40	7L	7L		0.00	0.00	524,520		524,520		524,520
41	7K-NGVENT, 7L-NGVENT	7K-NGVENT, 7L-NGVENT		0.00	0.00	1.24		1.24		1.24
42	NG-FUG	NG-FUG		0.00	0.00	20.9		20.9		20.9
43	SF6-FUG	SF6-FUG		0.00	0.00	<0.01		0.01		0.01
Notes:							**Total =**			**3,034,027**

[1] Elevated flare emission rate includes MSS emissions from vessel degassing.

[2] Baseline period is January 2009 through December 2010.

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TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	CO2e	**Permit:**	TBD
Baseline Period:	N/A	**to**	N/A

	Affected or Modified Facilities[2] FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions[5]	Projected Actual Emissions	Difference (B - A) [6]	Correction [7]	Project Increase[8]
Olefins 3 Plant Sources										
1	OL3-FUR1	OL3-FUR1		0.00	0.00	99,865		99,865		99,865
2	OL3-FUR2	OL3-FUR2		0.00	0.00	99,865		99,865		99,865
3	OL3-FUR3	OL3-FUR3		0.00	0.00	99,865		99,865		99,865
4	OL3-FUR4	OL3-FUR4		0.00	0.00	99,865		99,865		99,865
5	OL3-FUR5	OL3-FUR5		0.00	0.00	99,865		99,865		99,865
6	OL3-FUR6	OL3-FUR6		0.00	0.00	99,865		99,865		99,865
7	OL3-FUR7	OL3-FUR7		0.00	0.00	99,865		99,865		99,865
8	OL3-FUR8	OL3-FUR8		0.00	0.00	99,865		99,865		99,865
9	OL3-FUR9	OL3-FUR9		0.00	0.00	99,865		99,865		99,865
10	OL3-BOIL1	OL3-BOIL1		0.00	0.00	164,754		164,754		164,754
11	OL3-BOIL2	OL3-BOIL2		0.00	0.00	164,754		164,754		164,754
12	OL3-BOIL3	OL3-BOIL3		0.00	0.00	164,754		164,754		164,754
13	OL3-BOIL4	OL3-BOIL4		0.00	0.00	164,754		164,754		164,754
14	PDH-REAC1	PDH-REAC1		0.00	0.00	289,840		289,840		289,840
15	PDH-REAC2	PDH-REAC2		0.00	0.00	289,840		289,840		289,840
16	PDH-REAC3	PDH-REAC3		0.00	0.00	289,840		289,840		289,840
17	PDH-REAC4	PDH-REAC4		0.00	0.00	289,840		289,840		289,840
18	OL3-FUG	OL3-FUG		0.00	0.00	77.97		77.97		77.97
19	PDH-FUG	PDH-FUG		0.00	0.00	15.76		15.76		15.76
20	OL3-FLR	OL3-FLR		0.00	0.00	128,455	See Note 1	128,455		128,455
21	OL3-LPFLR1	OL3-LPFLR1		0.00	0.00	1,040.7		1,040.7		1,040.7
22	OL3-LPFLR2	OL3-LPFLR2		0.00	0.00	1,040.7		1,040.7		1,040.7
23	OL3-DK1	OL3-DK1		0.00	0.00	211.6		211.6		211.6
24	OL3-DK2	OL3-DK2		0.00	0.00					
25	OL3-MAPD	OL3-MAPD		0.00	0.00	20.90		20.90		20.90
26	PDH-MSSVO	PDH-MSSVO		0.00	0.00	3.81		3.81		3.81
27	OL3-MSSVO	OL3-MSSVO		0.00	0.00	35.1		35.1		35.1
28	OL3-GEN	OL3-GEN		0.00	0.00	448.5		448.5		448.5
29	PDH-GEN	PDH-GEN		0.00	0.00	448.5		448.5		448.5
30	N6460FA/B	1087		2.72	2.72	3.29	See Note 2	0.57		0.57

Pollutant[1]:	CO2e	**Permit:**	TBD
Baseline Period:	N/A **to** N/A		

Affected or Modified Facilities[2]	FIN	EPN	Permit No.	Actual Emissions(3)	Baseline Emissions(4) A	Proposed Emissions(5) B	Projected Actual Emissions	Difference (B - A) (6)	Correction (7)	Project Increase(8)
LDPE Plant Sources										
31	LD-022A/B	LD-022A/B		0.00	0.00	32,306		32,306		32,306
32	LD-023A/B	LD-023A/B		0.00	0.00					
33	OL3-FLR	OL3-FLR		0.00	0.00	22,216	See Note 1	22,216		22,216
34	LD-014	LD-014		0.00	0.00	17,810		17,810		17,810
35	LD-015	LD-015		0.00	0.00	17,810		17,810		17,810
36	LD-002	LD-002		0.00	0.00	229.1		229.1		229.1
37	NG-FUG	NG-FUG		0.00	0.00	425.2		425.2		425.2
38	LD-MSS	LD-MSS		0.00	0.00	0.08		0.08		0.08
Combined Cycle Turbine Sources										
39	7K	7K		0.00	0.00	525,024		525,024		525,024
40	7L	7L		0.00	0.00	525,024		525,024		525,024
41	7K-NGVENT, 7L-NGVENT	7K-NGVENT, 7L-NGVENT		0.00	0.00	25.1		25.1		25.1
42	NG-FUG	NG-FUG		0.00	0.00	425.2		425.2		425.2
43	SF6-FUG	SF6-FUG		0.00	0.00	29.6		29.6		29.6
	Summary of Contemporaneous Changes						**Total**			**3,990,283**

Notes:

[1] Elevated flare emission rate includes MSS emissions from vessel degassing.

[2] Baseline period is January 2009 through December 2010.

APPENDIX C

CCS DETAILED BACT ANALYSIS AND SUPPLEMENTAL INFORMATION

BACT FOR CARBON CAPTURE AND SEQUESTRATION

FPC TX addresses the potential to capture GHG emissions that are emitted from Carbon Capture and Sequestration (CCS) candidate sources associated with the 2012 Expansion Project listed below (plant names in parenthesis):

- 9 cracking furnaces (Olefins Expansion)
- 4 PDH Reactors (Olefins Expansion)
- 4 steam boilers (Olefins Expansion)
- PDH regeneration vents (Olefins Expansion)
- 2 combined cycle gas-fired turbines (Gas Turbines)
- 2 regenerative thermal oxidizers (LDPE)

The EPA five step top down BACT evaluation for this potential control technology options is provided in this Appendix. As shown in that analysis, CCS is not only not commercially available, not technically feasible but also economically unreasonable. Therefore, it is not included as a BACT option for any of the emissions sources associated with the 2012 Expansion Project.

6.1.1 STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The emerging carbon capture and sequestration (CCS) technologies generally consist of processes that separate CO_2 from combustion or process flue gas (capture component), the compression and transport component, and then injection into geologic formations such as oil and gas reservoirs, unmineable coal seams, and underground saline formations (sequestration component). These three components of CCS are addressed separately below:

Carbon Capture:

Of the emerging CO_2 capture technologies that have been identified, only amine absorption is currently commercially used for state-of-the-art CO_2 separation processes. The U.S. Department of Energy's National Energy Technology Laboratory (DOE-NETL) provides the following brief description of state-of-the-art post-combustion CO_2 capture technology and related implementation challenges. Although the DOE-NETL discussions focus on CCS application at combustion units in electrical generation service, elements of this discussion are applicable when discussing the application of CCS to sources in the chemical manufacturing industry. The following excerpts from DOE-NETL Information Portal illustrate some of the many challenges, but not all, that are present in applying available CO_2 Capture technologies at combustion and process sources located at chemical manufacturing plants.

> *…In the future, emerging R&D will provide numerous cost-effective technologies for capturing CO_2 from power plants. At present, however, state-of-the-art technologies for existing power plants are essentially limited to amine absorbents. Such amines are used extensively in the petroleum refining and natural gas processing industries… Amine solvents are effective at absorbing CO_2 from power plant exhaust streams—about 90 percent removal—but the highly energy-intensive process of regenerating the solvents decreases plant electricity output…*[1]

In its CCS information portal, the DOE-NETL adds:

> *…Separating CO_2 from flue gas streams is challenging for several reasons:*
>
> - *CO_2 is present at dilute concentrations (13-15 volume percent in coal-fired systems and 3-4 volume percent in gas-fired turbines) and at low pressure (15-25 pounds per square inch absolute [psia]), which dictates that a high volume of gas be treated.*
> - *Trace impurities (particulate matter, sulfur dioxide, nitrogen oxides) in the flue gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes.*

It should be noted that the majority of the candidate CCS source vent streams (previously listed in this section) are dilute in CO_2 concentration and contain impurities such as PM, NO_X and SO_2, thus increasing the challenge of CO_2 separation for the Point Comfort expansion project.

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[1] DOE-NETL, *Carbon Sequestration: FAQ Information Portal*, http://extsearch1.netl.doe.gov/search?q=cache:e0yvzjAh22cJ:www.netl.doe.gov/technologies/carbon_seq/FAQs/tech-status.html+emerging+R%26D&access=p&output=xml_no_dtd&ie=UTF-8&client=default_frontend&site=default_collection&proxystylesheet=default_frontend&oe=ISO-8859-1 (last visited July 26, 2012).

Compression and Transport:

The compression aspect of this component of CCS will represent a significant cost and additional environmental impact because of the energy required to provide the amount of compression needed. This is supported by DOE-NETL who states that:

> *Compressing captured or separated CO_2 from atmospheric pressure to pipeline pressure (about 2,000 psia) represents a large auxiliary power load on the overall plant system…*[2]

If CO_2 capture and compression can be achieved at a process or combustion source, it would need to be routed to a geologic formation capable of long-term storage. The long-term storage potential for a formation is a function of the volumetric capacity of a geologic formation and CO_2 trapping mechanisms within the formation, including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock. The DOE-NETL describes the geologic formations that could potentially serve as CO_2 storage sites and their associated technical challenges as follows:

> *Geologic carbon dioxide (CO_2) storage involves the injection of supercritical CO_2 into deep geologic formations (injection zones) overlain by competent sealing formations and geologic traps that will prevent the CO_2 from escaping. Current research and field studies are focused on developing better understanding of 11 major types of geologic storage reservoir classes, each having their own unique opportunities and challenges. Understanding these different storage classes provides insight into how the systems influence fluids flow within these systems today, and how CO_2 in geologic storage would be anticipated to flow in the future. The different storage formation classes include: deltaic, coal/shale, fluvial, alluvial, strandplain, turbidite, eolian, lacustrine, clastic shelf, carbonate shallow shelf, and reef. Basaltic interflow zones are also being considered as potential reservoirs. These storage reservoirs contain fluids that may include natural gas, oil, or saline water; any of which may impact CO_2 storage differently…*[3]

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[2] *Id.*

[3] DOE-NETL, *Carbon Sequestration: Geologic Storage Focus Area,* http://www.netl.doe.gov/technologies/carbon_seq/corerd/storage.html (last visited July 26, 2012)

Therefore, as can be seen from the DOE-NETL Information Portal, CCS as a whole cannot be considered a commercial available, technically feasible option for the combustion and process vent emissions sources under review in the FPC TX proposed expansion. FPC TX's expansion project generates flue gas streams that contain CO_2 in dilute concentrations and the project is not located in an acceptable geological storage location. Even so, FPC TX provides even further and more detailed evaluation to address all 5 steps of the EPA BACT analysis.

6.1.2 Step 2: Eliminate Technically Infeasible Options

Although, as described above, CCS should not be considered an available control technology, in this section, FPC-TX addresses, in more detail, the potential feasibility of implementing CCS technology as BACT for GHG emissions from the proposed expansion project GHG emission sources. The feasibility issues are different for each component of CCS technology (i.e., capture; compression and transport; and storage). Therefore, technical feasibility of each component is addressed separately below.

6.1.2.1 CO_2 Capture

Though 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 to process vents at chemical manufacturing plants.

The Obama Administration's Interagency Task Force on Carbon Capture and Storage, in its recently completed report on the current status of development of CCS systems for power plants, states that carbon capture could be used on combustion units. However, the following discussion on carbon capture technology availability for high volume vent streams and large combustion unit shows that carbon capture is not commercially available for application.

Large commercial applications, such as the expansion project sources, present even more difficult application of carbon capture, in part, due to the additional variability in flow volumes as typically experienced in chemical plants. Therefore, the discussion related to power plants also shows that of CO_2 capture for chemical process combustion and process vent stream are not commercially available.

Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment.[4]

In its current CCS research program plans (which focus on power plant application), the DOE-NETL confirms that commercial CO_2 capture technology for large-scale combustion units (e.g., power plants) is not yet available and suggests that it may not be available until at least 2020:

> *The overall objective of the Carbon Sequestration Program is to develop and advance CCS technologies that will be ready for widespread commercial deployment by 2020. To accomplish widespread deployment, four program goals have been established:*
>
> *(1) Develop technologies that can separate, capture, transport, and store CO_2 using either direct or indirect systems that result in a less than 10 percent increase in the cost of energy by 2015;*
>
> *(2) Develop technologies that will support industries' ability to predict CO_2 storage capacity in geologic formations to within ±30 percent by 2015;*
>
> *(3) Develop technologies to demonstrate that 99 percent of injected CO_2 remains in the injection zones by 2015;*
>
> *(4) Complete Best Practices Manuals (BPMs) for site selection, characterization, site operations, and closure practices by 2020. Only by accomplishing these goals will CCS technologies be ready for safe, effective commercial deployment both domestically and abroad beginning in 2020 and through the next several decades.*[5A]

To corroborate that commercial availability of CO_2 capture technology for large-scale combustion (power plant) projects will not occur for several more years, Alstom, one of the major developers of commercial CO_2 capture technology using post-combustion amine absorption, post-combustion chilled ammonia absorption, and oxy-combustion, states on its web

[4] *Report of the Interagency Task Force on Carbon Capture and Storage* at 50 (Aug. 2010).

[5] DOE-NETL, *Carbon Sequestration Program: Technical Program Plan,* at 10 (Feb. 2011).

site that its CO_2 capture technology will become commercially available in 2015.[6] However, it should be noted that in committing to this timeframe, the company does not indicate whether such technology will be available for CO_2 emissions generated from chemical plant sources, like those included in the Point Comfort expansion project.

6.1.2.2 CO_2 Compression and Transport

Notwithstanding the fact that the above discussion demonstrates that the carbon capture component of CCS is not commercial available for chemical plant combustion and process vents, FPC TX provides the following discussion concerning technical feasibility. This discussion further supports that the compression and transport component of CCS may be technically feasible but, as explained later, the cost evaluation shows that it is not economically reasonable. Therefore, CCS is not BACT for the 2012 Expansion Project.

Even if it is assumed that CO_2 capture could feasibly be achieved for the proposed project, the high-volume CO_2 stream generated would need to be compressed and transported to a facility capable of storing it. Potential geologic storage sites in Texas, Louisiana, and Mississippi to which CO_2 could be transported if a pipeline was constructed are delineated on the map found at the end of this Appendix.[7] The hypothetical minimum length required for any such pipeline(s) is the distance to the closest site with recognized potential for some geological storage of CO_2, which is an enhanced oil recovery (EOR) reservoir site located within 15 miles of the proposed project. However, none of the South and Southeast Texas EOR reservoir or other geologic formation sites have yet been technically demonstrated for large-scale, long-term CO_2 storage.

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 approximately 370 miles away (see the map at the end of this Appendix for the test site location). Therefore, to access this potentially large-scale storage capacity site,

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[6] Alstom, *Alstom's Carbon Capture Technology Commercially "Ready to Go" by 2015*, Nov.30, 2010, http://www.alstom.com/australia/news-and-events/pr/ccs2015/ (last visited July.26, 2012).

[7] Susan Hovorka, University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, *New Developments: Solved and Unsolved Questions Regarding Geologic Sequestration of CO_2 as a Greenhouse Gas Reduction Method* (GCCC Digital Publication #08-13) at slide 4 (Apr. 2008), available at: http://www.beg.utexas.edu/gccc/forum/codexdownloadpdf.php?ID=100(last visited July 26, 2012).

assuming that it is eventually demonstrated to indefinitely store a substantial portion of the large volume of CO_2 generated by the proposed project, a very long and sizable pipeline would need to be constructed to transport the large volume of high-pressure CO_2 from the plant to the storage facility, thereby rendering implementation of a CO_2 transport system infeasible.

The potential length of such a CO_2 transport pipeline is uncertain due to the uncertainty of identifying a site(s) that is suitable for large-scale, long-term CO_2 storage. The hypothetical minimum length required for any such pipeline(s) is estimated to be the lesser of the following:

- The distance to the closest site with established capability for some geological storage of CO_2, which is an enhanced oil recovery (EOR) reservoir site[8] located more than 600 kilometers from the proposed project; or
- The distance to a CO_2 pipeline that Denbury Green Pipeline-Texas is currently constructing approximately 150 kilometers (straight line distance) from the project site for the purpose of providing CO_2 to support various EOR operations in Southeast Texas beginning in late 2013.

6.1.2.3 CO_2 Sequestration

Even if it is assumed that CO_2 capture and compression could feasibly be achieved for the proposed project and that the CO_2 could be transported economically, the feasibility of CCS technology would still depend on the availability of a suitable pipeline or sequestration site as addressed in Step 4 of the BACT analysis. The suitability of potential storage sites is a function of volumetric capacity of their geologic formations, CO_2 trapping mechanisms within formations (including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock), and potential environmental impacts resulting from injection of CO_2 into the formations. Potential environmental impacts resulting from CO_2 injection that still require assessment before CCS technology can be considered feasible include:

- Uncertainty concerning the significance of dissolution of CO_2 into brine,

---

[8] None of the nearby South Texas EOR reservoirs or other geologic formation sites have been technically demonstrated for large-scale, long-term CO_2 storage.

- Risks of brine displacement resulting from large-scale CO_2 injection, including a pressure leakage risk for brine into underground drinking water sources and/or surface water,
- Risks to fresh water as a result of leakage of CO_2, including the possibility for damage to the biosphere, underground drinking water sources, and/or surface water,[9] and
- Potential effects on wildlife.

Potentially suitable storage sites, including EOR sites and saline formations, exist in Texas, Louisiana, and Mississippi. In fact, sites with such recognized potential for some geological storage of CO_2 are located within 15 miles of the proposed project, but such nearby sites have not yet been technically demonstrated with respect to all of the suitability factors described above. In comparison, the closest site that is currently being field-tested to demonstrate its capacity for geological storage of the volume of CO_2 that would be generated by the proposed power unit, i.e., SWP's SACROC test site, is located in Scurry County, Texas approximately 370 miles away. It should be noted that, based on the suitability factors described above, currently the suitability of the SACROC site or any other test site to store a substantial portion of the large volume of CO_2 generated by the proposed project has yet to be fully demonstrated.

6.1.3 STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

As documented above, implementation of CCS technology for the FPC TX expansion emission sources is not currently commercially available or feasible for both technical and economic reasons. Even so, FPC TX will provide detailed economic and impacts analyses in Step 4 which provides further documentation for eliminating this option as a control Technology to be evaluated for the GHG emission sources associated with the FPC TX expansion.

6.1.4 STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

6.1.4.1 Additional Environmental Impacts and Considerations

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

9 *Id.*

example, operation of carbon capture equipment at a typical natural gas fired combined cycle 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).[10] To provide the amount of reliable electricity needed to power a capture system, FPC TX would need to significantly expand the scope of the utility plant expansion 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.

FPC TX would need to construct a pipeline that is estimated to be at least 100 miles in length to transport captured GHGs to the nearest potential purchaser (Denbury Green Pipeline). Constructing a pipeline of this magnitude 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.

Finally, implementation of CCS for the 2012 Expansion Project poses several operational and business concerns. First, the sale of CO_2 material to either a pipeline entity or to a storage facility (EOR) would be made under contractual terms. FPC TX is in the primary business of selling commodity and specialty chemicals; the sale of CO_2 would be a secondary product. The GHG sources that would be tied into a CCS system must be periodically taken out of service for maintenance or other reasons to ensure maximum yield of primary product from the production unit, thereby temporary eliminating or reducing the supply of CO_2 to the buyer. FPC TX has identified contractual issues relating to the sale of CO_2 that conflict directly with existing contracts relating to the sale of primary products. For this reason, FPC TX believes that the sale of CO_2 from the Point Comfort expansion sources poses an unacceptable business conflict.

[10] 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

6.1.4.2 CCS Cost Evaluation

Based on the reasons provided above, FPC TX believes that CCS technology should be eliminated from further consideration as a potential feasible control technology for purposes of this BACT analysis. Furthermore, the Congressional Budget Office's June 2012 document entitled *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide* states that "average capital costs for a CCS-equipped plant would be 76 percent higher than those for a conventional plant."[11] Even so, to address possible questions that the public or the EPA may have concerning the relative costs of implementing hypothetical CCS systems, FPC TX has estimated such costs.

For the cost evaluation, FPC TX considered all plants project (Olefins Expansion, LDPE plant and gas turbines) associated the expansion GHG emission sources for which CCS is considered technically feasible, for purposes of this analysis, even though separate permits are requested for each plant. These GHG emissions sources include the following emission units (respective plant names/permit applications shown in parenthesis):

- 9 cracking furnaces (Olefins Expansion)
- 4 PDH Reactors (Olefins Expansion)
- 4 steam boilers (Olefins Expansion)
- PDH regeneration vent (Olefins Expansion)
- 2 combined cycle gas-fired turbines (Gas Turbines)
- 2 regenerative thermal oxidizers (LDPE Plant)

FPC TX's cost estimation is conservatively low because it does not include additional costs for the following items that would be needed to implement CCS for the FPC TX 2012 Expansion Project:

- additional gas conditioning and stream cleanup to meet specifications for final sale
- thousands of feet of gas gathering system piping to collect vent gas from sources located in different operating units
- costs of additional electric generating units required to power the capture and compression system (including design, procurement, permitting, installation, operating and maintenance costs)

[11] *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide,* Page 7 (June 2012).

- cost of obtaining rights of way for construction of a pipeline

These items would require significantly more effort to estimate and, since the conservatively low cost estimate demonstrates that this technology is not economically reasonable, it was not necessary to expend the extra time and resources to gather this additional data for the cost analysis.

The CCS system cost estimate, excluding these additional capital expenditure items, is presented on Table 6-1 at the end of this Appendix. The total CCS system cost is estimated at over 300 million dollars, which is more than 15% of the total Point Comfort expansion project capital cost (total estimated capital cost is 2 billion dollars). Based on the Congressional Budget Office's indications, this estimate of cost as a percentage of the total capital investment is conservatively low. Increasing the capital cost of the expansion project by this margin and increasing the ongoing operating and maintenance costs would render this project economically unviable. The margins of additional capital and operating costs are significantly greater if the aforementioned additional capital cost items, which were excluded, are taken into consideration.

As discussed above, CCS was determined to be not commercially available and not technically feasible; therefore, a detailed examination of the energy, environmental, and economic impacts of CCS is not required for this application. However, at the request of EPA Region 6, FPC-TX included the estimated costs for implementation of CCS which are presented in Table 6-1. As discussed above these costs show that CCS is not commercially available, not technically feasible but also economically unreasonable. Therefore, it is not included as BACT for the FPC TX expansion.

6.1.5 STEP 5: SELECT BACT

As demonstrated in Steps 2 and 4 of the BACT review, CCS is not only not commercially available, not technically feasible but also economically unreasonable. Therefore, it is not included as BACT for the FPC TX expansion.

6.1.5.1 CCS in Other GHG Permits

FPC TX searched GHG permits issued by EPA Region 6 and other states. Only one permit included the use of CCS, the Indiana Gasification, LLC (IG) project, permit no. 147-30464-

00060 issued by the Indiana Department of Environmental Management (IDEM). The IG project proposes the construction of a coal gasification power plant that will produce liquefied carbon dioxide which will be compressed and piped several hundred miles to EOR facilities in the Gulf Coast region.

This project differs significantly from the Point Comfort expansion in most technical aspects, but it should also be noted that IG has secured federal loan guarantees and potentially state tax credits to make the project, including application of CCS, economically viable. Furthermore, on page 154 of 181 of the PSD/TV Permit, Step 4 of the GHG BACT evaluation for the acid gas removal units (the primary GHG emission vents) state that:

> *IG will not begin construction of this facility without a fully financed project agreement for the pipeline that provides for the pipeline to be in place and ready to receive liquefied CO_2 at the point when pipeline quality CO_2 is available.*

This statement provides evidence that the project, including application of CCS, hinges on the approval and contracts for a new CO_2 pipeline. It is clear from the following quote from the Indiana permit application that installation of CCS was not justified for this project as BACT. The GHG BACT evaluation for the proposed IG plant concludes that "Based on the technically feasibility analysis in Step 2, there are no viable control technologies for the control of GHG emissions from the acid gas recovery unit vent." This is consistent with the results of FPC TX's BACT analysis of CCS for the Point Comfort Expansion project.

Table 6-1
Range of Approximate Annual Costs for Installation and Operation of Capture, Transport, and Storage Systems for Control of CO_2 Emissions from the Point Comfort Expansion

Carbon Capture and Storage (CCS) Component System	Factors for Approximate Costs for CCS Systems	Annual System CO_2 Throughput (tons of CO_2 captured, transported, and stored) [1]	Pipeline Length for CO_2 Transport System (km CO_2 transported) [5]	Range of Approximate Annual Costs for CCS Systems ($)
Post-Combustion CO_2 Capture and Compression System				
Minimum Cost	$44.11 / ton of CO_2 avoided [2]	2,913,739		$128,525,043
Maximum Cost	$103.42 / ton of CO_2 avoided [3]	2,913,739		$301,336,173
Average Cost	$73.76 / ton of CO_2 avoided [4]	2,913,739		$214,930,608
CO_2 Transport System				
Minimum Cost	$0.91 / ton of CO_2 transported per 100 km [3]	2,913,739	150	$3,964,950
Maximum Cost	$2.72 / ton of CO_2 transported per 100 km [3]	2,913,739	150	$11,894,849
Average Cost	$1.81 / ton of CO_2 transported per 100 km [4]	2,913,739	150	$7,929,899
CO_2 Storage System				
Minimum Cost	$0.51 / ton of CO_2 stored [3, 6]	2,913,739		$1,480,248
Maximum Cost	$18.14 / ton of CO_2 stored [3, 6]	2,913,739		$52,865,995
Average Cost	$9.33 / ton of CO_2 stored [4]	2,913,739		$27,173,122
Total Cost for CO_2 Capture, Transport, and Storage Systems				
Minimum Cost	$45.98 / ton of CO_2 removed	2,913,739		$133,970,240
Maximum Cost	$125.65 / ton of CO_2 removed	2,913,739		$366,097,017
Average Cost	$85.81 / ton of CO_2 removed [4]	2,913,739		$250,033,629

[1] Assumes the maximum possible annual CO_2 emissions scenario and assumes that a capture system would be able to capture 90% of the total CO_2 emissions generated by the combustion turbines.

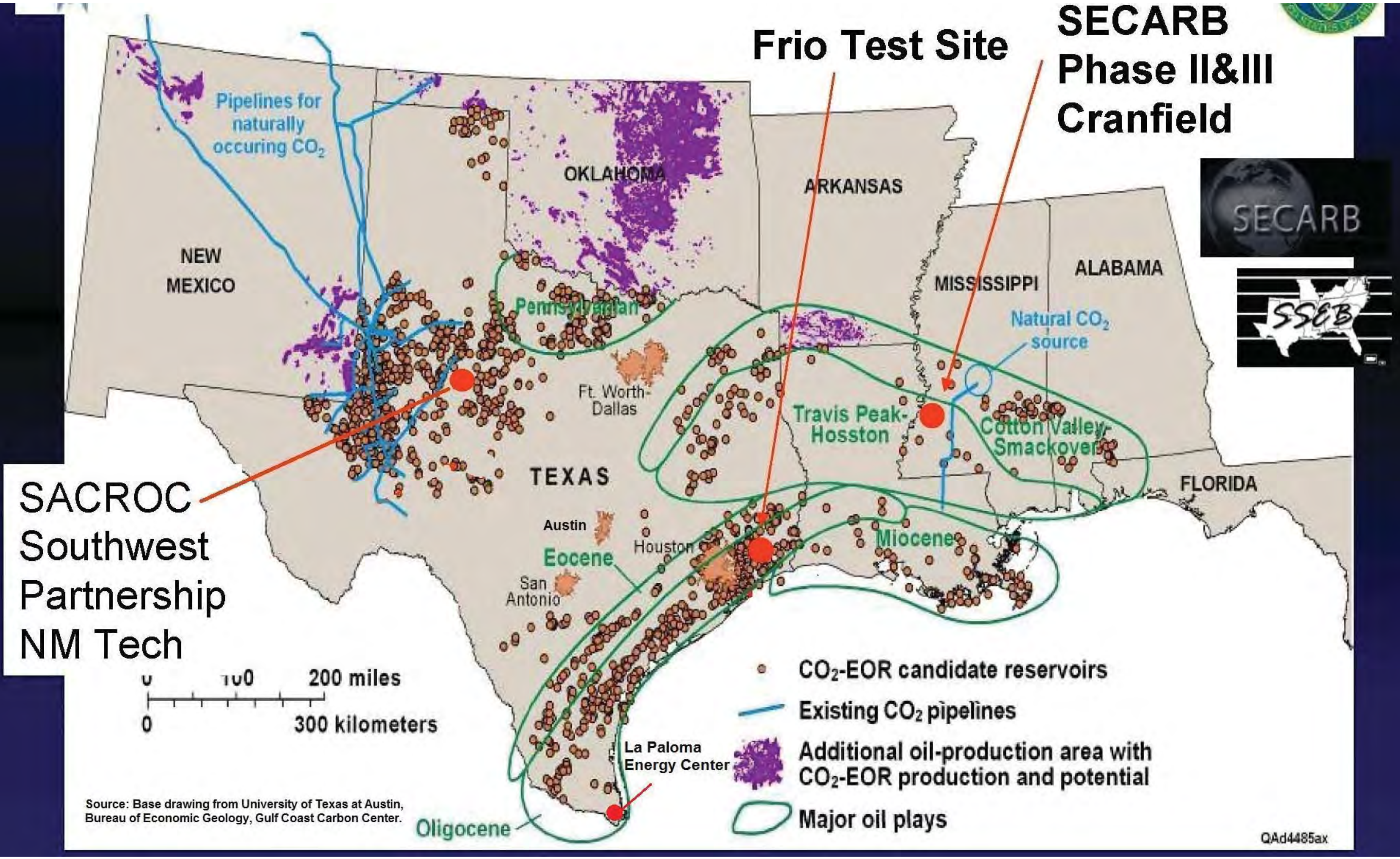
[2] This cost factor is the minimum found for implementation/operation of CO_2 capture systems within the cost-related information reviewed for CCS technology. The factor is from the on the "Properties" spreadsheet of the *Greenhouse Gas Mitigation Strategies Database* (Apr. 2010) (http://ghg.ie.unc.edu:8080/GHGMDB/#data), which was obtained through the EPA GHG web site (http://www.epa.gov/nsr/ghgpermitting.html). The factor is based on the increased cost of electricity (COE; in $/MW-h) resulting from implementation and operation at a CO_2 capture system on a natural gas-fired combined cycle power plant. The factor accounts for annualized capital costs, fixed operating costs, variable operating costs, and fuel costs.

[3] These cost factors are from *Report of the Interagency Task Force on Carbon Capture and Storage* , pp.33, 34, 37, and 44 (Aug. 2010) (http://www.epa.gov/climatechange/policy/ccs_task_force.html). The factors from the report in the form of $/tonne of CO_2 avoided, transported, or stored and have been converted to $/ton. Per the report, the factors are based on the increased cost of electricity (COE; in $/kW-h) of an "energy-generating system, including all the costs over its lifetime: initial investment, operations and maintenance, cost of fuel, and cost of capital".

[4] The average cost factors were calculated as the arithmetic mean of the minimum and maximum factors for each CCS component system and for all systems combined.

[5] The length of the pipeline was assumed to be the distance to the closest potential geologic storage site, as identified by the University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, available at: http://www.beg.utexas.edu/gccc/graphics/Basemap_state_lands_fp_lg.jpg (last visited Feb. 27, 2012).

[6] "Cost estimates [for geologic storage of CO_2] are limited to capital and operational costs, and do not include potential costs associated with long-term liability." (from the *Report of the Interagency Task Force on Carbon Capture and Storage* , p. 44)



Frio Test Site
SECARB
Phase II&III
Cranfield
SACROC
Southwest
Partnership
NM Tech
Pipelines for naturally occuring CO_2
OKLAHOMA
ARKANSAS
NEW MEXICO
MISSISSIPPI
ALABAMA
Natural CO_2 source
Pennsylvanian
Ft. Worth-Dallas
Travis Peak-Hosston
Cotton Valley-Smackover
TEXAS
FLORIDA
Austin
Houston
Eocene
Miocene
San Antonio
SECARB
SSEB
0 100 200 miles
0 300 kilometers
La Paloma Energy Center
CO_2-EOR candidate reservoirs
Existing CO_2 pipelines
Additional oil-production area with CO_2-EOR production and potential
Major oil plays
Source: Base drawing from University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center.
Oligocene
QAd4485ax

APPENDIX D

KELLY HART & HALLMAN MEMO
RE: EPA POLCY ON MULTIPLE PSD PERMITS

KELLY HART & HALLMAN
A PROFESSIONAL CORPORATION

MEMORANDUM

To: Brian Tomasovic

From: Bob Stewart and Steve Dickman

Date: July 13, 2012

Re: EPA Policy on Obtaining Multiple PSD Permits for a Single Source

I. Purpose of Memo and Short Answer

Factual Summary: Formosa Plastics Corp. ("FPC") intends to apply for federal Clean Air Act prevention of significant deterioration ("PSD") greenhouse gas permitting authorization from EPA for its olefins expansion project. This single project consists of three new related major greenhouse gas emission sources at its Point Comfort facility which should be authorized under three separate PSD permits, rather than under a single PSD permit. The first PSD permit will cover greenhouse gas emissions from the proposed new olefins 3 cracker and an associated propane dehydrogenation (PDH) unit; the second PSD permit will cover greenhouse gas emissions from a proposed new low density polyethylene (LDPE) resin plant; and the third PSD permit will cover greenhouse gas emissions from a new power utilities facility serving the other new units. Applying for three new PSD permits is desired by FPC for administrative and compliance reasons including organizational responsibility and accountability within FPC. In support of this approach, TCEQ has historically permitted FPC's various production facilities under separate PSD permits for criteria pollutants. FPC will subject all new units in the aggregate to normal PSD permitting requirements including application of BACT and fenceline air quality impacts analysis.

Issue: This proposal raises the question of whether it is permissible under EPA rules or policy guidance for FPC to obtain permitting of the new units under multiple PSD permits within a single PSD action rather than under a single PSD permit.

Short Answer: EPA has consistently stated that authorizing separate units at a major source facility under separate PSD permits is acceptable so long as doing so does not circumvent the full spectrum of PSD permitting requirements that would apply if the units were jointly permitted under a single permit.

II. Background Controversy Regarding the Aggregation Issue

The issue of use of multiple PSD permits most commonly arises in the context of the PSD Aggregation issue which is the question of whether multiple physical or operational changes must be grouped together, or "aggregated", as a single physical or operational change for purposes of determining applicability of PSD review. Typically, the Aggregation issue arises when a facility attempts to expedite a construction project by applying for several minor source permits for facility changes in order to evade or circumvent the more detailed PSD review that would occur if the changes were considered as a single "major source" PSD project or major modification. The Aggregation issue is important because of consequences in terms of higher costs and level of regulatory review associated with undergoing full PSD review.

EPA typically considers this issue on a case-by-case basis under three regulatory factors set forth in EPA rules along with a set other relevant factors identified in various EPA letters and memoranda. EPA rules as set forth in the definitions of "stationary source" and "building, structure, facility or installation" in 40 CFR Part 52 provide that two or more nominally-separate facility changes should be considered a single PSD project if they meet all of the following three criteria:

1. They belong to the same SIC major (2-digit) group. If two different project facilities could have separate SIC codes but a support relationship exists (e.g., 50% or more of the product of one facility is utilized by the other facility) then one facility is considered a support facility and this criterion is deemed to have been met.

2. They are located on one or more contiguous or adjacent properties in the same general area.

3. They are under common ownership or control. (If this is in dispute, then EPA will review any contractual agreements between the facilities to determine if they are under common control.)

Other various factors used by EPA in conjunction with the above test include:

- the closeness in time to the filing of applications for nominally-separate facility changes;
- whether the nominally-separate changes were considered together in the permittee's integrated facility planning documents or in financing proposals or in public statements;
- whether the nominally-separate facility changes are operationally dependent on each other;
- whether the nominally-separate facility changes are substantially related to each other in some other way;
- whether it is feasible for the permittee to operate a proposed facility change as a minor source without the other facility changes.

The purpose of EPA's Aggregation Policy is to prevent circumvention of PSD review. If multiple facility changes must undergo PSD review as a single PSD project then all relevant facility changes are considered together and are typically authorized under a single PSD permit. However, EPA has recognized that if the Aggregation Policy is so applied, all facilities need not necessarily be authorized under a single PSD permit.

III. Obtaining Separate PSD Permits for Separate Projects

A. The Nucor Case. The most recent expression of EPA policy on the subject of the Aggregation Policy and the use of multiple permits is an EPA Title V permit protest order signed by Lisa Jackson on March 23, 2012 in the case of Nucor Steel of Louisiana. In that case (copy attached), EPA granted three petitions for review of three Title V permits proposed to be issued to Nucor on the grounds that the Title V permits did not properly incorporate NSR permitting requirements as established in the Louisiana SIP. Specifically, the Louisiana Department of Environmental Quality ("LDEQ") had issued separate PSD permits and separate Title V permits to Nucor's pig iron process and its direct reduced iron ("DRI") manufacturing process both of which processes were located at a single site (in a NSR attainment area).

In its objections to Nucor's Title V permits, Zen-Noh Grain Corporation noted that even though both the pig iron process and the DRI process units would each be subject to BACT, LDEQ's proposal to allow separate PSD permitting of the two processes would circumvent the air quality impact analysis prerequisites for the entire Nucor facility. For example, for SO_2 and $PM_{10}/PM_{2.5}$ Nucor modeled only emissions from the DRI process and determined them to be below the significant impact level ("SIL") PSD threshold, but Zen-Noh's modeling showed that if aggregate emissions were modeled a full National Ambient Air Quality Standards ("NAAQS") analysis would have been required for SO_2 and PM_{10} and $PM_{2.5}$, and that the combined Nucor facility would cause a violation of NAAQS for these pollutants.

Pages 8 through 14 of the EPA Order discusses EPA's rationale for determining that emissions from both processes at Nucor should be aggregated. For the most part, EPA's rationale was that LDEQ had not sufficiently demonstrated why the two facilities should be considered separate sources. However, EPA made clear that even though Nucor was not attempting to avoid PSD review for either process since each process was individually a major source, "Nucor's ambient air quality impacts analysis did not consider whether the combined emissions from both the pig iron and DRI processes for all pollutants call for a more thorough cumulative analysis of the air quality impact of these sources." Thus, EPA did not object to the authorization of separate projects under separate PSD and Title V permits, it only objected to Nucor's failure to demonstrate that the combined air impacts of the combined projects met PSD requirements as would have been demonstrated if the two processes were considered in the aggregate.

B. Other EPA Policy Statements. In other cases, the EPA has indicated that having multiple PSD permits for a single PSD project is acceptable so long as doing so does not result in circumvention of PSD requirements that would otherwise apply.

In an EPA objection to Colorado's proposed Title V permit to TriGen-Colorado Energy Corporation which operates a power plant located at, and exclusively serving, the Coors Brewery, EPA required that the permittee's air emissions be aggregated with those of the Coors Brewery for PSD and Title V permitting purposes even though TriGen and Coors had separate PSD and Title V permits. EPA stated that "future modifications of the two facilities that make up a single source must be addressed together to calculate net emissions increases for comparison with NSR and PSD significance levels."

In a 2001 case concerning PSD applicability, EPA issued a determination that two adjacent and commonly-owned power generating facilities could be permitted separately as minor sources because regardless of whether the facilities each obtained a minor NSR permit, the permits would require BACT so that the facilities were not circumventing NSR emission control requirements by obtaining minor source permits. See, Oct. 12, 2001 letter "PSD Applicability for Frederickson Power, L.P." from Doug Cole, Acting Manager Federal & Delegated Air Programs Unit, EPA Region 10 to Grant Cooper and Raymond McKay.

In several cases where EPA has determined that co-located facilities should be aggregated, it has also specified that the facilities need not share a common Title V operating permit. For example, in a November 27, 1996 letter to Jennifer Schlosstein at Simpson Paper Company from Matt Haber of EPA Region 9, EPA stated "There is no need for Simpson and SMI to certify or assure compliance over each other in a Title V permit. EPA recommends that even though they are considered one source, each facility apply for a separate Title V permit, each with its own responsible official, under the Title V application process."

On August 2, 1996, EPA's Office of Air Quality Planning and Standards issued a policy memo concerning "Major Source Determinations for Military Installations" in which EPA stated:

> "After determining that stationary sources at a military installation are subject to Title V permitting, permitting authorities have discretion to issue more than one Title V permit to each major source at that installation, so long as the collection of permits assures that all applicable requirements would be met that otherwise would be required under a single permit for each major source."

EPA explained its rationale for allowing multiple Title V permits for different projects within a single facility in its November 15, 2002 order denying a petition for objection to the Title V permit for Shaw Industries in Georgia. According to the Georgia Environmental Protection Division, for administrative reasons Shaw requested that three separate Title V permits be issued for three different but co-located plants at the Shaw carpet manufacturing facility in Dalton, Georgia. EPA stated in its order:

> "Although multiple facilities meeting the definition of 'same source' must be evaluated as one source with respect to applicability, nothing in the CAA or Part 70 prohibits permitting authorities from issuing multiple Title V permits to one Part 70 source….. Thus under the CAA and EPA's regulations, a Part 70 source is free to request that it be issued more than one Part 70 permit, and permitting authorities are not prohibited from issuing multiple permits to facilities that together constitute a single source. However, permitting authorities that issue multiple permits should do so in a way that makes each facility's compliance obligations clear. Each permit narrative or statement of basis should refer to the other permits and explain the relationships between the facilities for purposes of applicability determinations. For instance, each permit narrative should indicate whether any changes at one facility may require offsetting measures at another facility."

Although the above EPA policy statements in the three immediately preceding cases specifically concern Title V permits, there is no reason why the same rationale should not apply to NSR and PSD permits, especially since EPA has specifically so ruled in the Nucor, TriGen and Frederickson cases discussed above.

IV. Conclusion

Based on the above-cited policy rulings, EPA has clearly accepted the practice of issuing PSD permits for multiple units located at a single major source facility. Separate PSD permits may be issued for separate units within a single PSD project so long as the issuance of separate permits does not allow the units in the aggregate to circumvent any regulatory requirements that would apply if the units were permitted in one permit as a single source .

In the case of FPC, although EPA's Aggregation Policy would clearly apply so as to require FPC to aggregate the emissions from its proposed new facility units, all of those emissions will undergo the full spectrum of PSD review in the aggregate. So long as FPC applies BACT to the new units and performs the required PSD air impacts analysis on an aggregated basis for all of the new units, the use of three separate PSD permits for a single PSD project is acceptable under past EPA practice. In addition, FPC will address any future modifications by evaluating the upstream and downstream effects of the modification on any one or more of the three PSD permits (and other permits) in order to determine the PSD significance thresholds for the modification permitting action. Consequently, the PSD analysis for future modifications would not in any way be circumvented by the fact that three PSD permits are in effect, but rather FPC will evaluate all increases in actual emissions resulting from the modification. Finally, as indicated in the Shaw Industries case, the reasons for utilizing multiple permits may simply be for purposes of administrative convenience of the permittee. In this case, FPC is requesting three separate PSD permits, each of which would be covered under individual Title V permits, in order to comply with future CAA certification requirements and maintain accountability. FPC uses a system designed to assure, through each unit's "chain of command," that the statements and information submitted are true, accurate and complete. Accordingly, EPA should have no legal or practical reasons for objecting to authorization of FPC's new single project for three new units under three separate PSD greenhouse gas permits.