

US EPA ARCHIVE DOCUMENT



Equistar Chemicals, L.P.
1515 Miller Cut-Off Road
P.O. Drawer D
Deer Park, TX 77536
Phone 713.209.7000

September 22, 2011

Jeffery Robinson
Permit Section Chief
U.S. Environmental Protection Agency, Region VI (6PD-R)
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202
Certified Mail: 7010 2780 0002 8137 6985

RECEIVED
11 SEP 29 PM 1:20
AIR PERMITS SECTION
6PD-R

Subject: GHG PSD Permit Application
Equistar Chemicals, L.P., La Porte Complex

Dear Mr. Robinson

Equistar Chemicals, L.P., La Porte Complex submits the attached application for a Greenhouse Gas (GHG) PSD permit. We are providing computer files of the application in WORD and EXCEL for EPA's use in working with this permit application.

Should you have any questions regarding this periodic report, please contact Gary Wojnowski at (713)209-1320.

Courtney Ruth
Complex Manager, La Porte Plant

attachments

PERMIT AMENDMENT APPLICATION
EQUISTAR CHEMICALS, L.P. ■ LA PORTE SITE

QE1 UNIT
PERMIT NUMBER 18978 AND 83822

PREPARED BY:

TRINITY CONSULTANTS
1001 W Loop S
Suite 640
Houston, Texas 77027
(713) 552-1371

September 2011

Project 114402.0080

Trinity 
Consultants

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY	1-1
2. TCEQ FORMS	2-1
3. AREA MAP	3-1
4. PLOT PLAN	4-1
5. PROCESS DESCRIPTION	5-1
6. PROCESS FLOW DIAGRAM	6-1
7. EMISSION CALCULATIONS	7-1
8. NEW SOURCE REVIEW ANALYSIS.....	8-1
8.1 PREVENTION OF SIGNIFICANT DETERIORATION (PSD) REGULATIONS	8-1
9. BEST AVAILABLE CONTROL TECHNOLOGY.....	9-1
9.1 GHG BACT ASSESSMENT METHODOLOGY.....	9-1
9.2 CRACKING FURNACES –GHG BACT	9-5
9.3 CRACKING FURNACE DECOKE STACK – CO ₂ BACT DISCUSSION.....	9-18
9.4 FLARES – GHG BACT.....	9-19
9.5 GHG BACT EVALUATION FOR FUGITIVE EMISSIONS.....	9-22
10. MATERIAL BALANCE	10-1
APPENDIX. EMISSION CALCULATIONS	

1. EXECUTIVE SUMMARY

LyondellBasell owns and operates a chemical manufacturing complex in La Porte, Harris County, Texas (La Porte Complex). The complex is divided into two operating areas and each area operates under a unique Texas Commission on Environmental Quality (TCEQ) Regulated Entity Number (RN) and Customer Number (CN) number:

- Olefins Unit and Polymers Units operated by Equistar Chemicals, LP (RN: 100210319, CN: 600124705), and
- Glacial Acetic Acid and Vinyl Acetate Monomer Units operated by LyondellBasell Acetyls, LLC (RN: 100224450, CN: 603674862).

For the purpose of federal regulatory applicability, the Equistar Facility and Acetyls Facility are contiguous and under common control and hence considered as one site in this permit application. The combined La Porte Complex is an existing major source.

The Equistar Facility includes the Olefins (QE-1) Unit which is authorized under NSR permit 18978/PSD-TX-752M3. Maintenance, startup, and shutdown (MSS) emissions from QE-1 are authorized under NSR permit 83822.

With this submittal, Equistar is requesting issuance of a PSD permit for GHG emissions. The project will include the following additions and modifications to the QE-1 Unit which impact GHG emissions.

- Three new cracking furnaces (EPNs: QE1010B, QE1011B, and QE1012B);
- A new decoking drum (EPN: QE1416FB);
- New fugitive components in GHG service (added to EPN: QEFUG); and
- Additional maintenance, startup, and shutdown (MSS) emissions associated with the periodic clean-out of the new and modified process vessels.

The combined La Porte Complex is an existing major source of greenhouse gas (GHG) emissions, with GHG emissions greater than 100,000 tons/year of CO₂e. The estimated GHG emissions associated with the proposed QE-1 project are above the GHG major modification threshold of 75,000 tons/year of CO₂e. Therefore, the proposed QE-1 expansion will trigger Federal PSD review for GHG emissions.

All required supporting documentation for the permit amendment is provided in this application. For reference, Page 1 of TCEQ Form PI-1 is included in Section 2 of this application. An area map indicating the site location and a plot plan identifying the location of various sources throughout the site are included in Sections 3 and 4 of the report, respectively. A process description and process flow diagram are presented in Sections 5 and 6, respectively. Emission calculations can be found in Section 7 of this application. Detailed New Source Review Analysis relating to the production increase project is provided in Section 8. Discussion of Best Available Control Technology (BACT) is provided in Section 9. A material balance is located in Section 10.



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

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: Equistar Chemicals LP		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name (<input checked="" type="checkbox"/> Mr. <input type="checkbox"/> Mrs. <input type="checkbox"/> Ms. <input type="checkbox"/> Dr.): Courtney F. Ruth		
Title: Complex Manager		
Mailing Address: P.O. Drawer D		
City: Deer Park	State: TX	ZIP Code: 77536-1900
Telephone No.: 713-336-5475	Fax No.: 713-767-1089	E-mail Address: courtney.ruth@lyondellbasell.com
C. Technical Contact Name (<input checked="" type="checkbox"/> Mr. <input type="checkbox"/> Mrs. <input type="checkbox"/> Ms. <input type="checkbox"/> Dr.): Gary Wojnowski		
Title: Principal Environmental Engineer		
Company Name: Equistar Chemicals LP		
Mailing Address: P.O. Drawer D		
City: Deer Park	State: TX	ZIP Code: 77536-1900
Telephone No.: 713-209-1320	Fax No.: 713-209-1440	E-mail Address: gary.wojnowski@lyondellbasell.com
D. Site Name: Equistar Chemicals La Porte Complex		
E. Area Name/Type of Facility: Olefins Unit	<input checked="" type="checkbox"/> Permanent <input type="checkbox"/> Portable	
F. Principal Company Product or Business: Ethylene Manufacturing		
Principal Standard Industrial Classification Code (SIC): 2869		
Principal North American Industry Classification System (NAICS): 325110		
G. Projected Start of Construction Date: March 1, 2013		
Projected Start of Operation Date: May 1, 2014		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 1515 Miller Cut-Off Road		
City/Town: La Porte	County: Harris	ZIP Code: 77571-9810
Latitude (nearest second): 29°42'54" N		Longitude (nearest second): 95°03'55" W



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

I. Applicant Information (continued)	
I. Account Identification Number (leave blank if new site or facility): HG-0770-G	
J. Core Data Form.	
Is the Core Data Form (Form 10400) attached? If <i>No</i> , provide customer reference number and regulated entity number (complete K and L).	<input type="checkbox"/> YES <input checked="" type="checkbox"/> NO
K. Customer Reference Number (CN): CN600124705	
L. Regulated Entity Number (RN): RN100210319	
II. General Information	
A. Is confidential information submitted with this application? If <i>Yes</i> , mark each confidential page confidential in large red letters at the bottom of each page.	<input type="checkbox"/> YES <input checked="" type="checkbox"/> NO
B. Is this application in response to an investigation or enforcement action? If <i>Yes</i> , attach a copy of any correspondence from the agency.	<input type="checkbox"/> YES <input checked="" type="checkbox"/> NO
C. Number of New Jobs: Unknown	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
Senator: Mario Gallegos	District No.: 6
Representative: Wayne Smith	District No.: 128
III. Type of Permit Action Requested	
A. Mark the appropriate box indicating what type of action is requested.	
Initial <input type="checkbox"/> Amendment <input checked="" type="checkbox"/> Revision (30 TAC 116.116(e)) <input type="checkbox"/> Change of Location <input type="checkbox"/> Relocation <input type="checkbox"/>	
B. Permit Number (if existing): 18978, 83822	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. (<i>check all that apply, skip for change of location</i>)	
Construction <input type="checkbox"/> Flexible <input type="checkbox"/> Multiple Plant <input type="checkbox"/> Nonattainment <input type="checkbox"/> Prevention of Significant Deterioration <input checked="" type="checkbox"/>	
Hazardous Air Pollutant Major Source <input type="checkbox"/> Plant-Wide Applicability Limit <input type="checkbox"/>	
Other: _____	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	<input type="checkbox"/> YES <input checked="" type="checkbox"/> NO



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

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.		<input type="checkbox"/> YES <input checked="" type="checkbox"/> 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.		<input type="checkbox"/> YES <input type="checkbox"/> NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?		<input type="checkbox"/> YES <input type="checkbox"/> 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:		
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.		<input checked="" type="checkbox"/> YES <input type="checkbox"/> 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).		<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO <input type="checkbox"/> To be determined
Associated Permit No (s.): O2223		
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.		
FOP Significant Revision <input checked="" type="checkbox"/> FOP Minor <input type="checkbox"/> Application for an FOP Revision <input type="checkbox"/> To Be Determined <input type="checkbox"/>		
Operational Flexibility/Off-Permit Notification <input type="checkbox"/> Streamlined Revision for GOP <input type="checkbox"/> None <input type="checkbox"/>		



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

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 <input type="checkbox"/>	GOP application/revision application: submitted or under APD review <input type="checkbox"/>
SOP Issued <input checked="" type="checkbox"/>	SOP application/revision application submitted or under APD review <input type="checkbox"/>
IV. Public Notice Applicability	
A. Is this a new permit application or a change of location application?	<input type="checkbox"/> YES <input checked="" type="checkbox"/> NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	<input type="checkbox"/> YES <input checked="" type="checkbox"/> NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO
D. Is this a state permit amendment application? If Yes, complete IV.D.1. – IV.D.3.	<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO
1. Is there any change in character of emissions in this application?	<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO
2. Is there a new air contaminant in this application?	<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	<input type="checkbox"/> YES <input checked="" type="checkbox"/> NO
E. List the total annual emission increases associated with the application (<i>list all that apply and attach additional sheets as needed</i>):	
Volatile Organic Compounds (VOC): 14.22 tpy	
Sulfur Dioxide (SO ₂): 3.73 tpy	
Carbon Monoxide (CO): 462.79 tpy	
Nitrogen Oxides (NO _x): 64.28 tpy	
Particulate Matter (PM): 51.76 tpy	
PM ₁₀ microns or less (PM ₁₀): 50.25 tpy	
PM _{2.5} microns or less (PM _{2.5}): 50.25 tpy	
Lead (Pb):	
Hazardous Air Pollutants (HAPs): 2.85	
Other speciated air contaminants not listed above: NH ₃ – 34.23 tpy	



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

V. Public Notice Information (complete if applicable)		
A. Public Notice Contact Name: Gary Wojnowski		
Title: Principal Environmental Engineer		
Mailing Address: P.O. Drawer D		
City: Deer Park	State: TX	ZIP Code: 77536-1900
Telephone No.: 713-209-1320	Fax No.: 713-209-1440	E-mail Address: gary.wojnowski@lyondellbasell.com
B. Name of the Public Place: La Porte Public Library		
Physical Address (No P.O. Boxes): 600 South Broadway St		
City: La Porte	County: Harris	ZIP Code:
Telephone No.: 281-471-4022	Fax No.:	E-mail Address:
The public place has granted authorization to place the application for public viewing and copying.		<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO
The public place has internet access available for the public.		<input checked="" type="checkbox"/> YES <input type="checkbox"/> 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: Ed Emmett		
Mailing Address: 1001 Preston, Suite 911		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.:	Fax No.:	E-mail Address:
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? (For Concrete Batch Plants)		<input type="checkbox"/> YES <input type="checkbox"/> NO
Presiding Officers Name(s) (<input type="checkbox"/> Mr. <input type="checkbox"/> Mrs. <input type="checkbox"/> Ms. <input type="checkbox"/> Dr.):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
Telephone No.:	Fax No.:	E-mail Address:



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

V. Public Notice Information (complete if applicable) (continued)		
3. Provide the name, mailing address of the chief executives of the city and county, State, Federal Land Manager, or Indian Governing Body for the location where the facility is or will be located.		
Chief Executive: Mayor Louis R. Rigby		
Mailing Address: 604 W. Fairmont Parkway		
City: La Porte	State: TX	ZIP Code: 77571
Telephone No.: 281-471-5020	Fax No.:	E-mail Address:
Name of the State or Federal Land Manager (<input type="checkbox"/> Mr. <input type="checkbox"/> Mrs. <input type="checkbox"/> Ms. <input type="checkbox"/> Dr.):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
Telephone No.:	Fax No.:	E-mail Address:
Name of the Indian Governing Body (<input type="checkbox"/> Mr. <input type="checkbox"/> Mrs. <input type="checkbox"/> Ms. <input type="checkbox"/> Dr.):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
Telephone No.:	Fax No.:	E-mail Address:
D. Bilingual Notice		
Is a bilingual program required by the Texas Education Code in the School District?		<input checked="" type="checkbox"/> YES <input type="checkbox"/> 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?		<input checked="" type="checkbox"/> YES <input type="checkbox"/> 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?		<input type="checkbox"/> YES <input checked="" type="checkbox"/> NO
B. Is the site a major stationary source for federal air quality permitting?		<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?		<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?		<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO



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

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 <input checked="" type="checkbox"/>			
2. Plot Plan <input checked="" type="checkbox"/>			
3. Existing Authorizations <input checked="" type="checkbox"/>			
4. Process Flow Diagram <input checked="" type="checkbox"/>			
5. Process Description <input checked="" type="checkbox"/>			
6. Maximum Emissions Data and Calculations <input checked="" type="checkbox"/>			
7. Air Permit Application Tables <input checked="" type="checkbox"/>			
a. Table 1(a) (Form 10153) entitled, Emission Point Summary <input checked="" type="checkbox"/>			
b. Table 2 (Form 10155) entitled, Material Balance <input checked="" type="checkbox"/>			
c. Other equipment, process or control device tables <input checked="" type="checkbox"/>			
B. Are any schools located within 3,000 feet of this facility?			<input type="checkbox"/> YES <input checked="" type="checkbox"/> NO
C. Maximum Operating Schedule:			
Hours:24	Day(s):7	Week(s):52	Year(s):1
Seasonal Operation? If Yes, please describe in the space provide below.			<input type="checkbox"/> YES <input checked="" type="checkbox"/> NO
D. Have the planned MSS emissions been previously submitted as part of an emissions inventory?			<input type="checkbox"/> YES <input checked="" type="checkbox"/> 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 <i>disaster review</i> is required?			<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO
F. Does this application include a pollutant of concern on the <i>Air Pollutant Watch List (APWL)</i> ?			<input type="checkbox"/> YES <input checked="" type="checkbox"/> NO
VIII. State Regulatory Requirements			
Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment. <i>The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.</i>			
A. Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?			<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO
B. Will emissions of significant air contaminants from the facility be measured?			<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO
C. Is the Best Available Control Technology (BACT) demonstration attached?			<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO



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

VIII. State Regulatory Requirements (continued) 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.	
D. Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?	<input checked="" type="checkbox"/> YES <input type="checkbox"/> 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?	<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO
B. Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?	<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO
C. Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO
D. Do nonattainment permitting requirements apply to this application?	<input type="checkbox"/> YES <input checked="" type="checkbox"/> NO
E. Does prevention of significant deterioration permitting requirements apply to this application?	<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO
F. Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	<input type="checkbox"/> YES <input checked="" type="checkbox"/> NO
G. Is a Plant-wide Applicability Limit permit being requested?	<input type="checkbox"/> YES <input checked="" type="checkbox"/> NO
X. Professional Engineer (P.E.) Seal	
Is the estimated capital cost of the project greater than \$2 million dollars?	<input checked="" type="checkbox"/> YES <input type="checkbox"/> 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: 340012	Fee Amount: \$75,000.00
Company name on check: Equistar	Paid online?: <input type="checkbox"/> YES <input checked="" type="checkbox"/> NO
Is a copy of the check or money order attached to the original submittal of this application?	<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO <input type="checkbox"/> N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO <input type="checkbox"/> N/A



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

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.

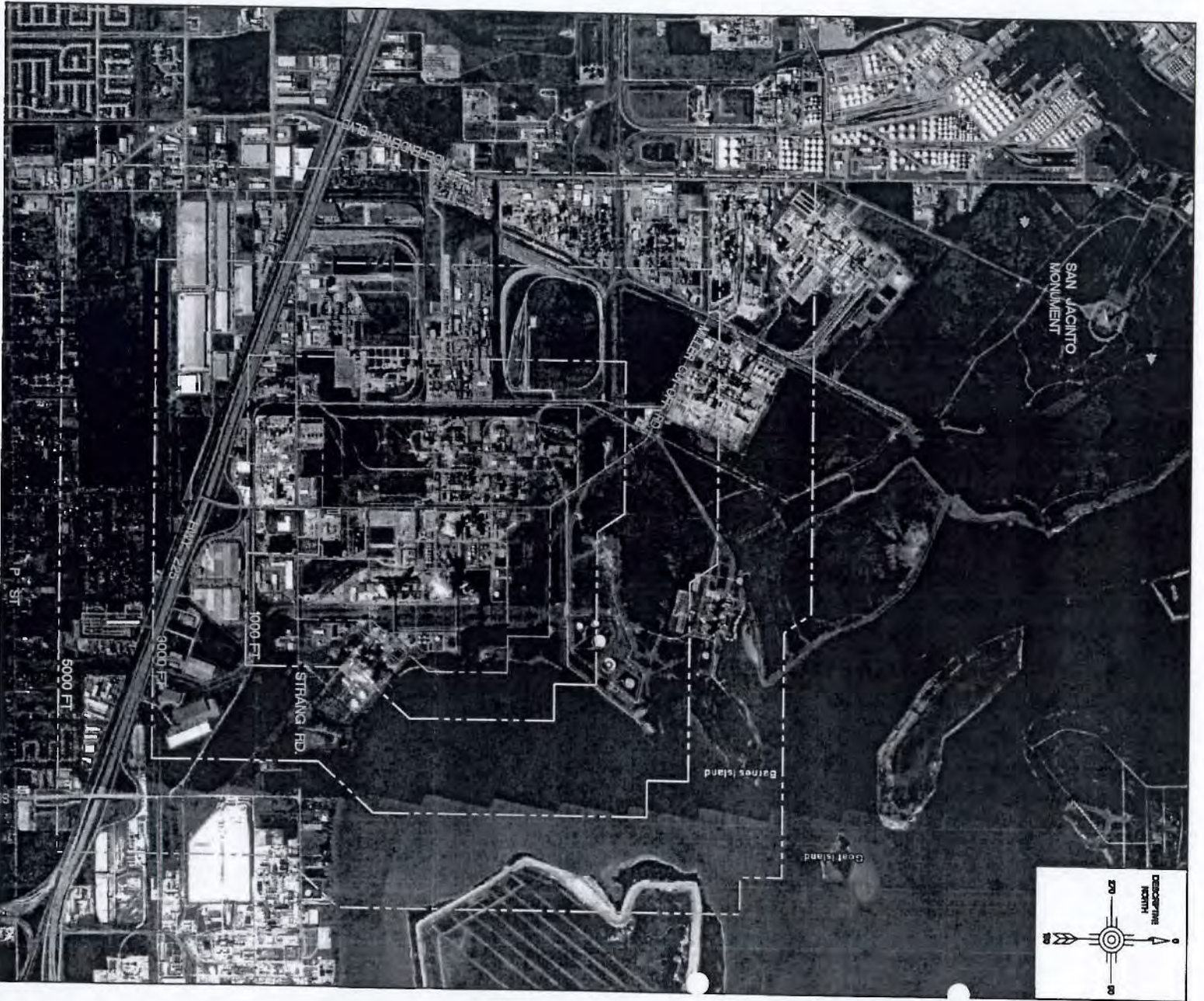
Name: COURTNEY RUTH

Signature: *Courtney Ruth*

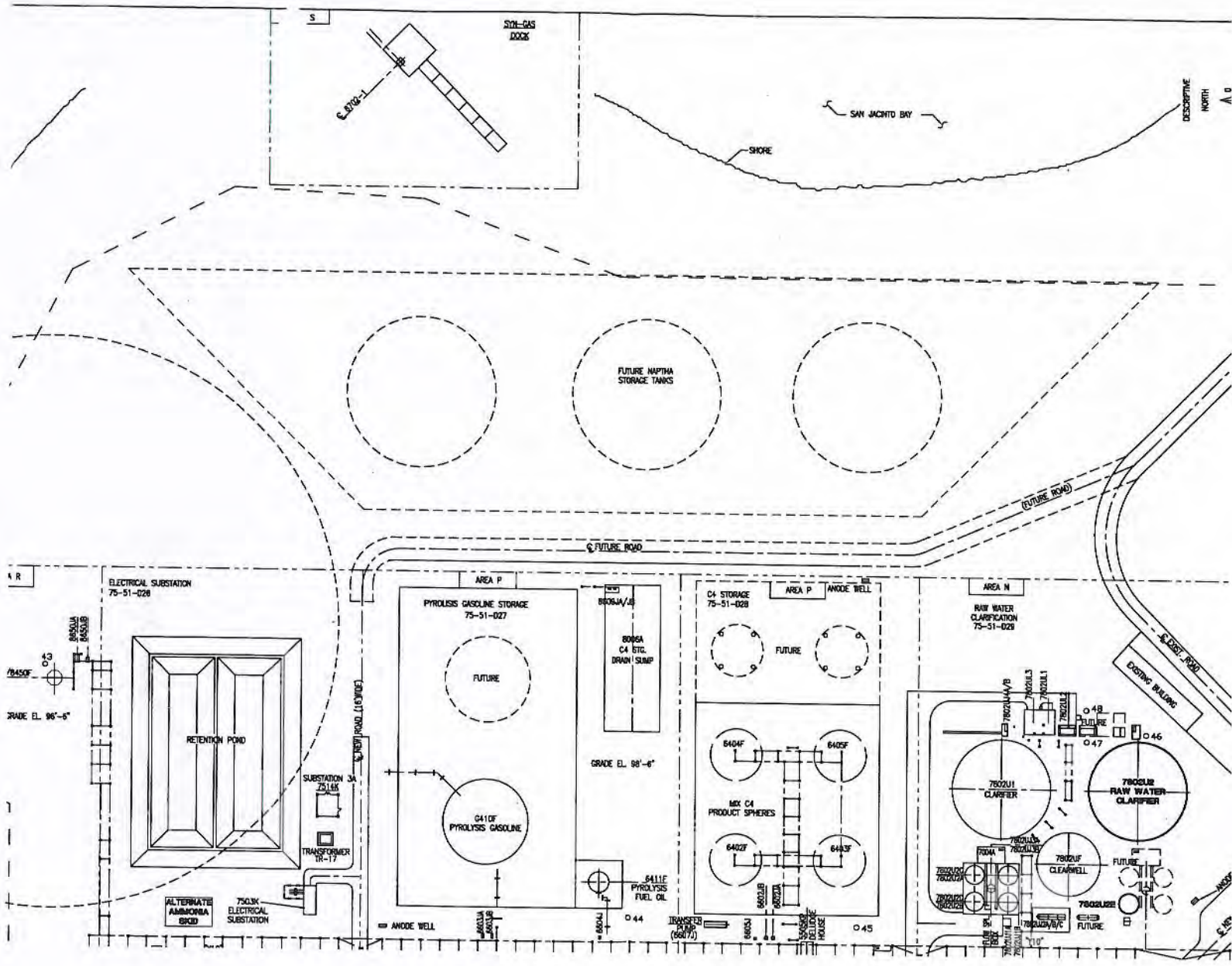
Original Signature Required

Date: 9-21-11

3. AREA MAP



4. PLOT PLAN



5. PROCESS DESCRIPTION

The Olefins unit receives hydrocarbon feedstock where it is fed into pyrolysis furnaces. The pyrolysis furnaces, which are fired on natural gas and/or process gas, heat the feedstock to a high temperature where it cracks and reforms as alkenes or olefins. This expansion installs 3 new cracking furnaces to bring the QE-1 unit total to 12.

The process effluent from the furnaces is quenched and scrubbed with water. Pyrolysis gasoline is removed as a product during water scrubbing. The quenched gases are compressed, dried, and cooled prior to beginning a series of purification/distillation steps. A hydrogen rich stream from the final chilling step is further purified in a pressure swing absorber to produce hydrogen product.

The purification section consists of a demethanizer, deethanizer, acetylene recovery unit (ARU), depropanizer, methyl acetylene propadiene conversion unit (MAPD), debutanizer, C3 splitter, and C2 splitter. This equipment separates the process gas stream into acetylene, ethylene, propylene, mixed C4s, and pyrolysis gasoline (pygas) products. Ethane and propane recovered during distillation and separation are recycled as feedstock into the pyrolysis furnaces.

Periodically, coke (primarily carbon) deposited in the furnace tubes must be removed. This decoking operation consists of two steps, of which only the second produces GHG emissions:

- an initial steam purge which moves hydrocarbons and coke particles further into the process, then
- a burn step which produces CO and CO₂, and routes the vent stream including coke particles to a cyclone separator.

6. PROCESS FLOW DIAGRAM

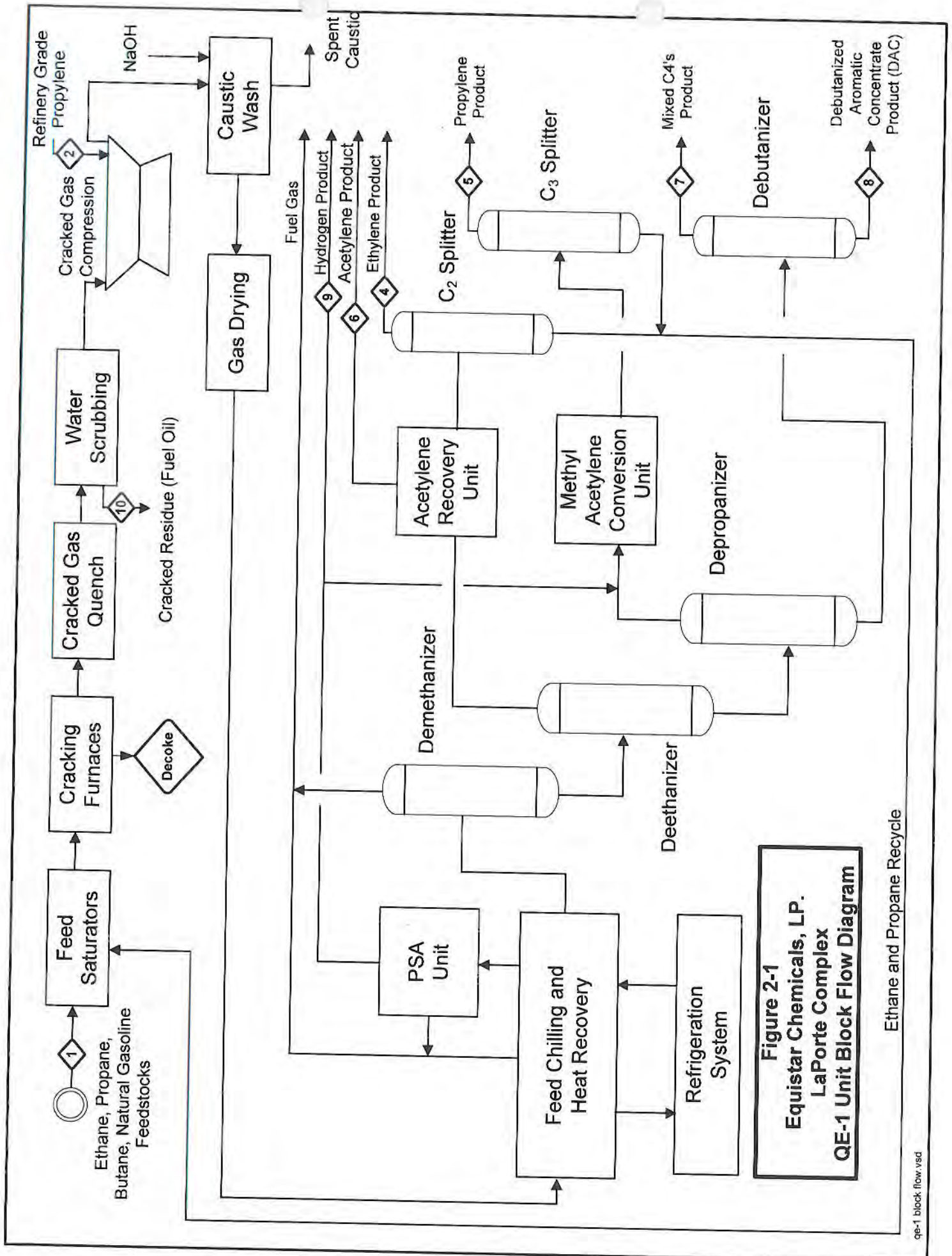


Figure 2-1
Equistar Chemicals, LP.
LaPorte Complex
QE-1 Unit Block Flow Diagram

Ethane and Propane Recycle

7. EMISSION CALCULATIONS

Detailed GHG emission calculations are included in the Appendix A.

TABLE 7-1. GHG EMISSIONS

EPN	Description	CO ₂ e metric tons/yr
QE3050B	ARU Flare	5,554
QE8050B	Elevated Flare	29,954
QE1010B, QE1011B, QE1012B	Furnaces 10-12	657,198
QE1416FB	Decoking Drum	1,040
QEFUG	Process Fugitives	1,307



TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date	September 2011	Permit No.:	18978, 83822	Regulated Entity No.:	100210319
Area Name:	Equistar Chemicals, L.P., QE1 Unit			Customer Reference No.:	600124705

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this table

1. Emission Point			AIR CONTAMINANT DATA		
(A) EPN	(B) FIN	(C) NAME	2. Component of Air Contaminant Name	3. Air Contaminant Emission Rate MTCE/yr (A)	TPY (B)
QE1010B	QE1010B	Furnace 10	CO ₂	218,851	241,174
			CH ₄	87	4.55
			N ₂ O	128	0.45
QE1011B	QE1011B	Furnace 11	CO ₂	218,851	241,174
			CH ₄	87	4.55
			N ₂ O	128	0.45
QE1012B	QE1012B	Furnace 12	CO ₂	218,851	241,174
			CH ₄	87	4.55
			N ₂ O	128	0.45
QE1416FB	QE1416FB	Process Fugitives Decoking Drum	CH ₄	1307	68.59
QE3050B	QE3050B	ARJ Flare Maintenance (Including Startups & Shutdowns)	CO ₂	1040	1146.04
			CO ₂	5477	6037.35
QE8050B	QE8050B	Elevated Flare Maintenance (Including Startups & Shutdowns)	CH ₄	77.35	4.06
			CO ₂	29541	32563.37
			CH ₄	413	21.68

EPN = Emission Point Number
FIN = Facility Identification Number



TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date	September 2011	Permit No.:	18978, 83822
Area Name:	Equistar Chemicals, L.P., QEI Unit	Regulated Entry No.:	100210319
		Customer Reference No.:	600124705

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this table

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS										
(A) EPN	(B) FIN	(C) NAME	4. UTM Coordinates of Emission			5. Building Height (Feet)	6. Height Above Ground (Feet)	7. Stack Exit Data			8. Fugitives		
			Zone	East (Meters)	North (Meters)			(A) Diameter (Feet)	(B) Velocity (fps)	(C) Temperature (°F)	(A) Length (Ft)	(B) Width (Ft)	(C) Axis Degrees
QE1010B	QE1010B	Furnaces 10	15			160		8.6	38.5	270			
QE1011B	QE1011B	Furnaces 11	15			160		8.6	38.5	270			
QE1012B	QE1012B	Furnaces 12	15			160		8.6	38.5	270			
QEFUG	QEFUG	Process Fugitives	15										
QE1416FB	QE1416FB	Decoking Drum	15	300,661	3,288,042	150		3.5	80	550			
QE3050B	QE3050B	ARU Flare Maintenance (Including Startups & Shutdowns)	15	300,670	3,288,269	100		2	400	1831			
QE8050B	QE8050B	Elevated Flare Maintenance (Including Startups & Shutdowns)	15	300,968	3,288,419	340		7.5	400	1831			

EPN = Emission Point Number
FIN = Facility Identification Number

8. NEW SOURCE REVIEW ANALYSIS

8.1 PREVENTION OF SIGNIFICANT DETERIORATION (PSD) REGULATIONS

The La Porte facility is a major source of GHG emissions and the proposed change meets the definition of a major modification under the GHG tailoring rule. Therefore, this application is being submitted for a GHG PSD permit.

The following steps are performed during an analysis to determine PSD applicability:

1. Determine the emission increases from the proposed projects.

Calculate emission increases as a result of the proposed project. If the increases from the proposed projects are less than the *de minimis* levels, no additional PSD review is required. If the emissions are greater than the *de minimis* levels, further review is required.

2. Determine the beginning and ending dates for the contemporaneous period.

The contemporaneous period commences five years prior to the date construction started and extends to the date of commencement of operation.

3. Determine creditable emission increases or decreases during the contemporaneous period on a pollutant-by-pollutant basis.

An emission increase is the amount by which the new level of “actual emissions” at the emissions unit exceeds the old level. The new level of “actual emissions” is the proposed permitted emission rate after the modification. The old level of “actual emissions” is calculated based on the average of any 24-month period of operation, which occurred within 10 years preceding the modification. No existing source that emits CO₂e is being modified; all CO₂e project increases come from new sources. Therefore, the baseline is equal to zero.

4. Determine net emission increase.

The net emission increase is the sum of all contemporaneous and creditable emission increases and decreases and includes the emission increases and decreases from the proposed modification. If the net emission increase from the proposed modification is greater than the corresponding PSD *de minimis* emission rate, PSD review must be performed for that pollutant. If the net emission increase is less than the PSD *de minimis* emission rate, no additional review is required.

8.1.1 APPLICABILITY ANALYSIS

Emissions increases associated with this project for GHG are greater than the corresponding de minimis levels, as shown in the table below. Hence, the emissions increases trigger PSD for GHG. PSD permitting requirements are addressed in the following sections.

TABLE 8-1. PSD APPLICABILITY SUMMARY

	GHG (tpy)
Project Emission Increase (tpy)	694,013
PSD Significant Emission Rate (tpy)	75,000
PSD Review Required?	YES

8.1.2 BACT REVIEW

PSD regulations require Best Available Control Technology (BACT) review for all equipment that is physically or operationally modified. The following emission sources of GHG are being physically or operationally modified as part of this project: three new cracking furnaces, new decoking drum, additional fugitive components, and MSS emissions from the two flares. Therefore, federal BACT review does apply. BACT requirements are addressed in Section 9 of this application.

8.1.3 AIR QUALITY ANALYSIS

Localized GHG emissions are not known to cause adverse public health or environmental impacts. Rather, GHG emissions are anticipated to contribute to long-term environmental consequences on a global scale. Accordingly, EPA's Climate Change Workgroup has characterized the category of regulated GHGs as a "global pollutant." Given the global nature of impacts from GHG emissions, NAAQS are not established for GHGs in the Tailoring Rule and a dispersion modeling analysis for GHG emissions is not a required element of a PSD permit application for GHGs.

9. BEST AVAILABLE CONTROL TECHNOLOGY

9.1 GHG BACT ASSESSMENT METHODOLOGY

Greenhouse Gas (GHG) Best Available Control Technology (BACT) for the facility has been evaluated via a “top-down” approach which includes the steps outlined in the following subsections.

GHG emissions increases from the Olefins Expansion are greater than 100,000 tons per year (tpy) expressed as carbon dioxide equivalents (CO₂e). Therefore, the project is subject to regulation under PSD and a BACT review must be conducted for each of the GHG pollutants and applicable emission units. In the proposed project, GHGs are emitted from the following sources:

- Furnaces (EPNs: QE1010B, QE1011B, QE1012B)
- Decoking Drum (EPN: QE1416FB)
- Flares (EPNs: QE3050B, QE8050B)
- Fugitive Emissions (EPN: QEFUG)

The emission sources listed above generate GHG emissions in one of the following ways: combustion or fugitive emissions. GHG emissions of CO₂, CH₄, and N₂O are anticipated as a result of combustion at the flare and within the cracking furnace. The additional sources of GHGs include CH₄ fugitive emissions from piping components.

U.S. EPA has issued limited guidance documents related to the completion of GHG BACT analyses. The following guidance documents were utilized as resources in completing the GHG BACT evaluation for the proposed project:

- *PSD and Title V Permitting Guidance For Greenhouse Gases* (hereafter referred to as General GHG Permitting Guidance)²
- *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boiler* (hereafter referred to as GHG BACT Guidance for Boilers)³
- *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Petroleum Refining Industry* (hereafter referred to as GHG BACT Guidance for Refineries)⁴

² U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: March 2011). <http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf>

³ U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). <http://www.epa.gov/nsr/ghgdocs/iciboilers.pdf>

⁴ U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). <http://www.epa.gov/nsr/ghgdocs/refineries.pdf>

BACT TOP DOWN APPROACH

9.1.1 STEP 1 - IDENTIFY CONTROL TECHNOLOGIES

Available control technologies with the practical potential for application to the emission unit and regulated air pollutant in question are identified. Available control options include the application of alternate production processes and control methods, systems, and techniques including fuel cleaning and innovative fuel combustion, when applicable and consistent with the proposed project. The application of demonstrated control technologies in other similar source categories to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental, energy, economic or other impacts; control technologies with potential application to the emission unit under review are identified in this step.

The following resources are typically consulted when identifying potential technologies for criteria pollutants:

1. EPA's Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database;
2. Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies;
3. Engineering experience with similar control applications;
4. Information provided by air pollution control equipment vendors with significant market share in the industry; and/or
5. Review of literature from industrial technical or trade organizations.

Equistar will rely primarily on items (3) through (5) above, and the following additional resources such:

- RBLC database – Searching the newly enhanced RBLC database returned no results on permitting decisions for gaseous fuel and gaseous fuel mixture combustion in Process Code 11.300, synthetic organic chemical manufacturing industry (SOCMI), in Process Code 64.000, or flares in Process Code 19.300.⁵
- GHG Mitigation Strategies Database – The GHG Mitigation Strategies Database did not contain any information for emission sources presented in this analysis.⁶

9.1.2 STEP 2 - ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling the PSD-triggering pollutant emissions from the source in question. The first question in determining whether or not a technology is feasible is

⁵ <http://cfpub.epa.gov/RBLC/>

⁶ <http://ghg.ic.unc.edu:8080/GHGMDB/>

whether or not it is demonstrated. Demonstrated has specific meaning in this regard. Demonstrated “means that it has been installed and operated successfully elsewhere on a similar facility.” “This step should be straightforward for control technologies that are demonstrated--if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible.”⁷

An undemonstrated technology is only technically feasible if it is “available” and “applicable.” A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is “commercially available”.⁸ Control technologies in the R&D and pilot scale phases are not considered available. Based on EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source. Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative. The NSR Manual explains the concept of applicability as follows: “An available technology is “applicable” if it can reasonably be installed and operated on the source type under consideration.”⁹ Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the NSR Manual.

9.1.3 STEP 3 - RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

All remaining technically feasible control options are ranked based on their overall control effectiveness for the pollutant under review.

9.1.4 STEP 4 - EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked option from consideration it is selected as the basis for the BACT limit. Alternatively, in the judgment of the permitting agency, if unreasonable adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until a control technology is identified.

Please note that the GHG BACT assessment presents a unique challenge with respect to the evaluation of CO₂ and CH₄ emissions. The technologies that are most frequently used to control emissions of CH₄ in hydrocarbon-rich streams (e.g., flares and thermal oxidizers) actually convert CH₄ emissions to CO₂ emissions. Consequently, the reduction of one GHG (i.e., CH₄) results in a proportional increase in emissions of another GHG (i.e., CO₂).

⁷ NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.17.

⁸ NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18.

⁹ NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18.

Permitting authorities have historically considered the effects of multiple pollutants in the application of BACT as part of the PSD review process, including the environmental impacts of collateral emissions resulting from the implementation of emission control technologies. To clarify the permitting agency's expectations with respect to the BACT evaluation process, states have sometimes prioritized the reduction of one pollutant above another. For example, technologies historically used to control NO_x emissions frequently caused increases in CO emissions. Accordingly, several states prioritized the reduction of NO_x emissions above the reduction of CO emissions, approving low NO_x control strategies as BACT that result in elevated CO emissions relative to the uncontrolled emissions scenario.

According to 40 CFR §52.21(b)(49)(ii), CO₂e emissions must be calculated by scaling the mass of each of the six GHGs by the gas's associated global warming potential (GWP), which is established in Table A-1 to Subpart A of 40 CFR Part 98. Therefore, to determine the most appropriate strategy for prioritizing the control of CO₂ and CH₄ emissions, Equistar considered each component's relative GWP. As presented in Table 9-1, the GWP of CH₄ is 21 times the GWP of CO₂. Therefore, one ton of atmospheric CH₄ emissions equates to 21 tons of CO₂e emissions. On the other hand, one ton of CH₄ that is combusted to form CO₂ emissions prior to atmospheric release equates to 2.7 tons of CO₂e emissions. Since the combustion of CH₄ decreases GHG emissions by approximately 87 percent on a CO₂e basis, combustion of CH₄ is preferential to direct emissions of CH₄.

TABLE 9-1. GLOBAL WARMING POTENTIALS

Pollutant ¹	GWP ²
CO ₂	1
CH ₄	21
N ₂ O	310

1. Only those GHGs for which quantifiable emissions increases are expected due to this project are listed.
2. GWPs are based on a 100-year time horizon, as identified in Table A-1 to 40 CFR Part 98, Subpart A.

9.1.5 STEP 5 - SELECT BACT

In the final step, the BACT emission limit is determined for each emission unit under review based on evaluations from the previous step.

Although the first four steps of the top-down BACT process involve technical and economic evaluations of potential control options (i.e., defining the appropriate technology), the selection of BACT in the fifth step involves an evaluation of emission rates achievable with the selected control technology.

NAAQS have not been established for GHGs and a dispersion modeling analysis for GHG emissions is not a required element of a PSD permit application for GHGs. Since localized short-term health and environmental effects from GHG emissions are not recognized, Equistar proposes to only implement the most stringent demonstrated and technologically feasible control as BACT.

9.2 CRACKING FURNACES –GHG BACT

The following section presents BACT evaluations for GHG emissions produced from the cracking furnace combustion process.

9.2.1 CRACKING FURNACES – CO₂ BACT

9.2.1.1 IDENTIFICATION OF POTENTIAL CO₂ CONTROL TECHNIQUES (STEP 1)

The following potential CO₂ control strategies for the furnaces were considered as part of this BACT analysis:

- ▲ Carbon capture and storage (CCS)
- ▲ Selection of the lowest carbon fuel
- ▲ Installation of energy efficient options for the furnaces
- ▲ Best Operational Practices

9.2.1.1.1 CARBON CAPTURE AND STORAGE

Carbon capture and storage (CCS) involves separation and capture of CO₂ emissions from the flue gas, compression of the captured CO₂, transportation of the compressed CO₂ via pipeline, and finally injection and long-term geologic storage of the captured CO₂. Several different technologies have demonstrated the potential to separate and capture CO₂. To date, some of these technologies have been demonstrated at the laboratory scale only, while others have been proven effective at the slip-stream or pilot-scale. Numerous projects are currently planned for the full-scale demonstration of CCS technologies.

According to the recently issued U.S. EPA guidance for PSD and Title V Permitting of Greenhouse Gases:

“For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is “available” for facilities emitting CO₂ in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO₂ streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing).¹⁰”

The guidance document doesn't specifically identify cracking furnaces in an olefins production process in the high purity CO₂ stream emitting sector; however similar furnaces are a component of hydrogen production, which is listed above. Therefore the flue gas produced by the furnaces contains typical combustion device levels of CO₂ and CCS is considered an “available” add-on

¹⁰ US EPA, Office of Air Quality Planning and Standards, “PSD and Title V Permitting Guidance for Greenhouse Gases”, March 2011, p. 32.

control technology for this flue gas stream. Currently there are two options for CO₂ capture from such flue gases: Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes.

Capture or separation of the CO₂ stream alone is not a sufficient control technology, but instead requires the additional step of permanent storage. After separation, storage could involve sequestering the CO₂ through various means such as enhanced oil recovery (EOR), saline aquifers, and sequestration in un-minable coal seams.

There are additional methods of sequestration such as potential direct ocean injection of CO₂ and algae capture and sequestration (and subsequent conversion to fuel); however, these methods are not as widely documented in the literature for industrial scale applications. As such, while capture-only technologies may be technologically available at a small-scale, the limiting factor is the availability of a mechanism (pipeline or geologic formation) to permanently sequester, store, or inject the captured gas. The Equistar, La Porte facility is not located near a permanent CO₂ sequester option; therefore EOR, Saline Aquifers, or un-minable coal seams are not a technically feasible option. The La Porte facility is located approximately 25 miles from the Denbury Green Pipeline (a commercial CO₂ pipeline); however the distance from the pipeline, the excessive cost of designing, constructing, and operating the pipeline to transport compressed CO₂ to the Denbury Green Pipeline; and lack of similar demonstrated projects make this sequestration option infeasible for this project.

In addition to the U.S. EPA permitting guidance for GHG, white papers for GHG reduction options were reviewed for discussion of CCS technologies. In the GHG BACT Guidance for Boilers white paper, a brief overview of the CCS process is provided and the guidance cites the Interagency Task Force on Carbon Capture and Storage for the current development status of CCS technologies.^{11,12} In the Interagency Task Force report on CCS technologies, a number of pre- and post- combustion CCS projects are discussed in detail; however, many of these projects are in formative stages of development and are predominantly power plant demonstration projects (and mainly slip stream projects). Capture-only technologies are technically available; however not commercially demonstrated. In addition, the limiting factor in CCS projects is typically the lack of a geologic formation or pipeline for the carbon to be permanently sequestered or the extremely high cost of the design, construction and operation of a CCS project.

¹¹ US EPA, "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial and Institutional Boilers," October 2010, p. 26, <http://www.epa.gov/nsr/ghgdocs/iciboilers.pdf>

¹² "Report of the Interagency Task Force on Carbon Capture and Sequestration," August 2010. <http://fossil.energy.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf>.

Beyond power plant CCS demonstration projects, the report also discusses three relevant industrial CCS projects that are being pursued under the Industrial Carbon Capture and Storage (ICCS) program for the following companies/installations:

- Leucadia Energy: a methanol plant in Louisiana where 4 million tonnes per year of CO₂ will be captured and used in an enhanced oil recovery (EOR) application.
- Archer Daniels Midland: an ethanol plant in Illinois where 900,000 tonnes per year of CO₂ will be captured and stored in a saline formation directly below the plant site.
- Air Products: a hydrogen-production facility in Texas where 900,000 tonnes per year of CO₂ will be captured and used in an EOR application.

At present, these industrial deployments were selected for funding in June 2010 and are moving onto a construction/demonstration phase. Therefore, they are not yet demonstrated. In addition, the Department of Energy is providing significant financial assistance for these projects to offset the cost and make these projects economically feasible.

In addition, the August 2010 federal Interagency Task Force for Carbon Capture and Storage (CCS) report noted the following four (4) fundamental near-term and long-term concerns for CCS:¹³

- The existence of *market failures*, especially the lack of a climate policy that sets a price on carbon and encourages emission reductions.
- The need for a *legal/regulatory framework* for CCS projects that facilitates project development, protects human health and the environment, and provides public confidence that CO₂ can be stored safely and securely.
- Clarity with respect to the *long-term liability for CO₂ sequestration*, in particular regarding obligations for stewardship after closure and obligations to compensate parties for various types and forms of legally compensable losses or damages.
- Integration of *public information, education, and outreach* throughout the lifecycle of CCS projects in order to identify key issues, foster public understanding, and build trust between communities and project developers.

9.2.1.1.2 SELECTION OF THE LOWEST CARBON FUEL

For GHG BACT analyses, low-carbon intensity fuel selection is the primary control option that can be considered a lower emitting process. The furnaces

¹³ Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, <http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf>, p. 53.

will combust natural gas as the primary fuel and may combust fuel gas containing H₂ as a secondary fuel when practicable and available. Natural gas is the lowest emitting GHG fuel on a direct carbon basis than all other typical fossil fuels. The use of fuel gas containing H₂ will further reduce the CO₂ emissions from this combustion source.

9.2.1.1.3 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE FURNACES

The first step in the production of olefins in the process known as steam cracking is energy intensive, and is the only significant source of GHG emissions in such an olefins manufacturing unit. This section describes the energy efficiencies incorporated in the design of Equistar's cracking furnaces.

Because operation of an olefins furnace is energy intensive, it is intentionally designed to maximize the energy efficiency in the various components of the furnace. In a typical olefins plant, more than 60% of energy consumption is in the olefins furnaces. The furnace addition by Equistar will maximize thermal efficiency as described in this document. Furnace design will incorporate the latest improvements in heat transfer and fluid flow to maximize the energy efficiency and energy recovery.

The major components of a furnace are

- Firebox or Radiant Section
- Burners
- Convection Section
- Fan
- Stack
- Quench Exchangers and Steam Drum

Firebox or Radiant Section

The firebox of an olefins furnace is the heart of the furnace where the cracking reaction takes place to thermally break down hydrocarbon feeds allowing them to reform as ethylene, propylene and other by-products. The cracking process is highly endothermic, and high amounts of heat must be input to the process fluids to break down the hydrocarbon feed to lighter gases. The reaction takes place inside process tubes, commonly referred to as radiant tubes or the radiant coil, where radiant heat is provided for the thermal cracking process by burners which heat the tubes in the radiant section of the furnace.

The radiant tubes in the firebox will be located in the center of the box in a configuration to minimize the shadowing effect of adjacent radiant tubes, which allows for increased radiant heat transfer to the radiant tubes and high radiant transfer efficiency. The firebox is vertical with the radiant tubes supported vertically in the center of the firebox, with burners on either side of the tubes. This allows radiant heat to be transferred uniformly, which

minimizes localized coke build-up inside the radiant tubes, reduces spots of overheating which reduce efficiency, and helps maintain high energy efficiency of radiant heat transfer.

Olefins cracking furnaces are known for extremely high operating temperatures. The temperature in an olefins furnace firebox will be on the order of 2100°F or higher. The higher the temperature of the object, the higher the radiant energy an object releases. Due to the high temperature in the firebox, the overwhelming majority of the heat transfer to the radiant tubes is through radiant heat transfer, as opposed to conductive or convective heat transfer. The hot firebox radiates heat to the relatively cold radiant tubes for thermal cracking. This radiant heat is similar to the heat one feels when standing a distance from a campfire where the air temperature is cold, but the heat can be clearly felt. In order to put this in context, the temperature range for basic petrochemical process heaters is typically less than 1600°F, and they tend to have less corresponding potential heat loss. The olefin furnaces proposed in this application have a fuel firing rate in excess of 400 MMBtu/hour in each furnace. The typical petrochemical process heater generally has a firing rate less than 200 MMBtu/hour and often the firing rate is less than 100 MMBtu/hour. Since the firebox temperature in an olefins furnace is high it is important to minimize heat loss from the firebox and it is important to have sufficient insulation to reduce the external metal temperature to values recommended by American Petroleum Institute. A combination of high temperature brick and ceramic fiber insulation of sufficient thickness will be used along the walls of the firebox, to reduce firebox heat loss and to maximize reflection of radiant heat back to the radiant tubes.

Another feature that Equistar will be using to maximize efficiency in the firebox is to minimize air infiltration from the entry and exit of radiant tubes in the firebox. Traditionally, the radiant tubes are supported from the top and bottom. However, penetration of radiant tube support guide pins through the radiant floor will not be used in this design so as to avoid unnecessary air intake which reduces furnace efficiency.

The radiant tubes will be hung from the top of the firebox in such a way as to minimize the number of penetrations of the box. Each opening where the radiant tubes enter and exit the firebox will be sealed to maintain high energy efficiency. Engineered insulation boots to cover the openings will be utilized to minimize air infiltration.

A typical olefins cracking furnace could have anywhere from 48 to 300 radiant tubes. If the process flow to each of the radiant tubes is not uniform, it will lead to uneven coke formation in different tubes. This will lead to higher heat requirement in tubes with coke build-up which decreases the heat transfer efficiency. The radiant tubes will be decoked as needed to maintain the heat

transfer efficiency. Also, in order to get uniform feed flow to each radiant tube for maximum furnace efficiency, critical sonic flow venturis will be installed at the inlet of each radiant tube. The uniform distribution of the feed to the radiant tubes and the uniform heating of the tubes are critical to the successful thermal cracking of the feed.

Burners

High efficiency burners will be installed in the firebox, on both sides of the radiant coil. Burners will be designed to handle the whole range of fuels combusted in the olefins plant cracking furnaces. In order to maintain the combustion efficiency the burner maintenance will be included in the preventative maintenance program. The burners will be inspected, while in service so the burner flame pattern can be observed, on a routine basis.

The burners will be located inside the firebox so as to maximize radiant heat transfer efficiency. State-of-the art computational flow dynamics modeling of the burner arrangement and burner flame pattern will be utilized to ensure proper firebox operation. A predictable and even heat distribution profile along the length of the radiant tubes is critical to the thermal cracking process. The burner flame envelopes for floor mounted burners are long and thin, with long highly luminous portions in the infrared spectrum parallel to the process tubes, again maximizing efficiency. The burners that will be installed in Equistar olefins furnaces will be tested at the burner vendor facility prior to installation and burner design optimized for maximizing efficiency and operability.

Burners will be designed to operate with minimum excess air to maintain high combustion efficiency. The furnace will be equipped with an oxygen analyzer to provide data used in the control of the combustion process. Operation with more than optimum excess air causes energy inefficiency leading to more fuel gas consumption. The burners will be designed to operate under the range of fuel gases combusted in the plant, including natural gas, and plant produced fuel gases.

Convection Section

The hot flue gases from the firebox enter the convection section to maximize heat recovery for achieving the optimum thermal efficiency for the furnace. In this section, the heat transfer occurs primarily by convection, with hot flue gases transferring heat to the convection tubes which are located horizontally in the convection section.

In a process heater which operates at lower temperatures, the convection section will be located directly above the radiant section. The convection

section in an olefins furnace with high firebox temperatures will not be located directly on top of the radiant section. There will be an off-set with respect to the firebox so that there is no direct radiation to the bottom rows of tubes in the convection section. Direct radiation could lead to localized overheating, reduced heat transfer and premature failure of tubes with more frequent start-ups and shutdowns.

The firebox in a modern cracking furnace could be over 60 feet long and 40 feet tall and the convection section could be over 60 feet long, 10 feet wide and 40 feet tall. The area between the radiant section and the convection section is called the transition section. The hot flue gases exiting the vertical firebox make a 90° horizontal turn over the entire firebox length and then another 90° vertical turn to enter the convection section. In order to maximize heat transfer, the transition section will be designed carefully to minimize channeling of flue gas. In addition, the first row of convection section tubes will be located above the transition floor with sufficient distance to allow for fully developed flue gas flow across the tubes for maximum heat recovery.

The convection section will have refractory along the walls of sufficient thickness to minimize heat loss from the convection walls and to meet American Petroleum Institute recommendations for external skin temperature. The convection tubes will be located in a triangular pattern between rows of tubes, or in triangular pitch, to maximize heat transfer to the tubes. In a triangular pattern, end tubes between alternating rows will have more gap between the tube and end wall. These larger gaps will be filled with refractory flow diverters called corbels which will be used to keep the same distance between end tubes and end walls in all rows of tubes. The corbels near the end tubes in each row break up flow and minimize flue gas channeling, thus maximizing efficiency.

The heat recovery in the convection section can be divided into two services - process service tubes with hydrocarbon and steam flowing from the convection tubes into the radiant section and waste heat recovery service tubes with boiler feed water and very high pressure steam. In order to minimize fuel gas usage, the process feed gas will be preheated in the convection section to the maximum extent practicable before entering the radiant section. The remaining flue gas heat will be recovered by preheating boiler feed water before the feed water enters a steam drum and by superheating the high pressure saturated steam which is generated in the steam drum.

The selective catalytic reduction (SCR) catalyst bed, for reduction of NO_x, will be an integral part of the convection section. When operating an SCR, there is an optimum temperature envelop for maximum NO_x reduction across the catalyst. There will be convection tube banks above and below the SCR catalyst bed. The heat in the flue gas is needed to heat other process fluids, as

described above, and is the driving force in the NO_x reduction reaction across the catalyst.

Heat recovery will be maximized for the range of operating conditions to get the flue gas exiting the convection section to the lowest temperature practicable. The temperature will be sufficiently low that further heat recovery is impractical.

Fan

It is important to control the excess oxygen required for combustion in order to maximize thermal efficiency of the furnace. An induced draft fan is located on top of the convection section to pull the flue gases up through the convection section. There is a stack damper located at the inlet to the fan. The draft is maintained at a minimum with the stack damper opening or closing to minimize infiltration of any tramp or unnecessary air. The induced draft fan in combination with the stack damper allow for oxygen to be controlled at the desired low level for efficiency (as described above).

Stack

Flue gases will exit the furnace through a stack located on top of the fan. Stack design is important to furnace efficiency because it contributes to an organized even flow of gases through the furnace. The stack will be designed to have sufficient velocity for the wide of range operating conditions that the furnace will encounter.

Quench Exchangers & Steam Drum

In order to offset rising utility costs, rising fuel costs, and to increase overall furnace efficiency, integral quench exchangers / steam drum will be provided with the furnace. While not uncommon, this design is not ubiquitous to cracking furnaces. The radiant tubes exit the firebox and are close coupled to the quench exchangers. The cracked gas passes from the radiant tubes to the quench exchangers where the gas is rapidly cooled from about 1500°F to less than 900°F. With gas crackers, the quench exchanger process outlet temperature could be cooled to as low as 400°F to improve the efficiency further. Water from the steam drum is circulated by natural circulation on the shell side as the cooling fluid to produce very high pressure steam, which is beneficially used in compressor drivers, further reducing overall energy consumption. Depending on the plant requirements, the steam drum will be designed to produce anywhere from 600 psig to 1700 psig.

9.2.1.1.4 BEST OPERATIONAL PRACTICES

Periodic Tune up – The furnaces, to the extent practicable and in accordance with usual industry preventative maintenance practices, are kept in good working condition. These tune-ups include a variety of activities ranging from instrument calibration to cleaning of dirty or fouled mechanical parts. With respect to GHG emissions potential, these activities maintain performance as opposed to enhancing performance.

Oxygen Trim Controls – The excess oxygen is measured post-combustion and those results are used to control inlet combustion air volume to maintain high efficiency. Introduction of too much excess air increases the mass in the furnace to be heated and reduces efficiency. Oxygen trim control allows the excess oxygen to be controlled to optimum levels, thus allowing the furnace to operate at continuous high levels of efficiency.

9.2.1.2 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

9.2.1.2.1 CARBON CAPTURE AND STORAGE

Capture and Compression

CO₂ capture is achieved by separating CO₂ from emission sources where it is then recovered in a concentrated stream that can be sequestered. Currently there are a few options for CO₂ capture from combustion device flue gas streams: Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes. Post-combustion capture uses solvent scrubbing, typically using monoethanolamine (MEA) as the solvent, is a commercially mature technology. Solvent scrubbing has been used in the chemical industry for separation of CO₂ in exhaust streams and is an available technology for this application.

Post-combustion membranes technology may also be used to separate or adsorb CO₂ in an exhaust stream. It has been estimated that 80 percent of the CO₂ could be captured using this technology. The captured CO₂ would then be purified and compressed for transport. The current state of this technology is primarily the research stage, with industrial application at least 10 years away; therefore post-combustion membranes are also technically infeasible because they are not currently demonstrated and available for this application.

Sequestration - Lack of Sequestration Sink (Geologic or Pipeline)

While capture-only technologies may be available and demonstrated on pilot scales, a remaining hurdle is the availability of a mechanism (pipeline or geologic formation) to permanently sequester the captured gas. As stated above, the closest existing pipeline is approximately 25 miles from the La Porte facility. The distance from the pipeline, the excessive cost of designing,

constructing, and operating the CCS project to transport compressed CO₂ to the Denbury Green Pipeline; and lack of similar demonstrated projects make this sequestration option infeasible for this project.

Based on the aforementioned technical challenges with capture, compression and storage of CO₂, CCS as a combined technology is not considered technically feasible as BACT for reducing CO₂ emissions from the furnaces. Accordingly, CCS is eliminated as a potential control option in this BACT assessment for CO₂ emissions due to technical infeasibility.

9.2.1.2.2 SELECTION OF THE LOWEST CARBON FUEL

Natural gas, the lowest carbon fuel, is a technically feasible option for CO₂ control of the furnaces. In addition, fuel gas containing H₂ may be used as a secondary fuel when practicable and available, which will further reduce CO₂ emissions. However, burners are designed for high efficiency and to minimize production of NO_x and CO. As a result, the fuel slate that is suitable for any specific burner is limited. A burner designed to accommodate 100% natural gas will have limits on the hydrogen content of a fuel mixture.

9.2.1.2.3 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE FURNACES

As presented in section 9.2.1.1.3, "Installation of Energy Efficiency Options on the Furnaces," the furnaces employed by Equistar incorporate many design features to provide continuous high efficiency operation. The operation of this type of furnace using the proposed fuel slate has been demonstrated and is technically feasible.

9.2.1.2.4 BEST OPERATIONAL PRACTICES

Periodic tune-up and oxygen trim control are common practices for combustion devices that can be described as best operational practices. These are low cost options, that have been demonstrated, and while they do not reduce GHG emissions, they prevent degradation of performance that would increase GHG emissions.

9.2.1.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

With elimination of CCS as an option, low carbon fuel selection, installation of energy efficient options, and implementation of operational control to maintain efficiency are the remaining technically feasible control options for minimizing CO₂ emissions from the cracking furnaces. Efficiency of design is, based on good engineering judgment, the primary contributor to reducing GHG emissions in any carbon based fuel fired device.

Use of a low carbon fuel, utilization of efficient design, and implementation of operational controls will be evaluated further in Step 4 of the BACT analysis.

As stated above, the best operational practices do not reduce GHG emissions but rather prevent performance degradation that would allow GHG emissions to increase.

9.2.1.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

9.2.1.4.1 SELECTION OF THE LOWEST CARBON FUEL

Natural gas is the lowest emitting carbon fuel that could be relied upon for the proposed operation. High H₂ fuel gas may be utilized as a secondary fuel for the furnaces when it is available and its use is practicable. The availability of hydrogen for combustion in the furnaces is not assured. As stated in section 9.2.1.2.2, burners in the furnaces are designed for a slate of fuels that limit hydrogen content. In addition, hydrogen is not always available and its consumption as fuel may not be practicable. While consumption of hydrogen as fuel creates no GHG emissions from that portion of the fuel, its use as a fuel in the furnaces cannot be assured and therefore there is no assurance that GHG emissions can be reduced.

9.2.1.4.2 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE FURNACES

The furnaces are being designed with the energy efficiencies described in section 9.2.1.1.3. High efficiency burners are being installed to further enhance overall energy efficiency, thereby reducing the GHG emissions potential of the largest source of GHG emissions in the olefins unit. The technologies being employed are proven and energy efficiency has the greatest impact on the emissions of GHGs from the unit.

9.2.1.4.3 BEST OPERATIONAL PRACTICES

The implementation of periodic tune-ups and the use of oxygen trim control do not reduce GHG emissions, but are useful in preventing degradation of performance that would allow GHG emissions to increase.

9.2.1.5 SELECTION OF CO₂ BACT (STEP 5)

Based on the top-down process described above for control of GHG from the furnaces, Equistar is proposing that the firing of natural gas as the primary fuel source and the operation of several energy efficiency options constitutes BACT for the furnaces. These energy efficiency options, fully described in Section 9.2.1.1.3, are summarized in Table 9-2.

TABLE 9-2. SUMMARY OF ENERGY EFFICIENCY OPTIONS FOR THE FURNACES

Energy Efficiency Option	Features of Furnace
Radiant section thermal efficiency.	Vertical process tubes combined with floor mounted burners. Highly luminous radiant section, maximizing radiant heat transfer. Process tube placement to assure uniform heating, and to minimize shadowing.
Sealed system	Minimize air infiltration with proper sealing of firebox penetrations.
Reduce heat loss.	Brick and ceramic fiber insulation to reduce heat loss.
Energy recovery	Preheating of process fluids in the convection section. Use of integral quench exchangers and steam drum.
Physical characteristics	Triangular pitch in convection section with corbels to control hot combustion gas flow and maximize transfer of heat into the process fluids. Properly sized and designed induced draft fan. Properly sized and placed stack.
Burner design	Long, thin flames parallel to tubes with highly luminous flame envelopes. Minimum excess air design to enhance efficiency.
Operating parameters	Careful control of feedstock/steam ratios, temperatures, pressures, and residence times to maximize production rate at normal firing rates.

9.2.2 CRACKING FURNACES - CH₄ BACT

9.2.2.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Available control options for minimizing CH₄ emissions from the furnaces include the selection of high efficiency burners and good combustion/operating practices to minimize fuel consumption.

9.2.2.2 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

Burner selection and energy efficient operating practices are the only technically feasible control options for reducing CH₄ emissions from the natural gas fired furnaces.

9.2.2.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

High efficiency burner selection and energy efficient operating practices are evaluated in the remaining steps of the CH₄ BACT analysis for the furnaces. It is unclear which option

has a more significant impact on emissions of CH₄ from the facility; and Equistar will employ both options. Therefore, no ranking of control options is performed.

9.2.2.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The most efficient, technically feasible control options to reduce CH₄ emissions involve installation of a high efficiency natural gas burners and use of energy efficient practices.

9.2.2.5 SELECTION OF CH₄ BACT (STEP 5)

Equistar will select the most efficient natural gas burners that meet the design criteria and is implementing the energy efficiency efforts as described in Section 9.2.1.5. Through these efforts to maximize the unit's efficiency, CH₄ emissions from the furnaces are inherently reduced and kept to a minimum.

9.2.3 CRACKING FURNACES - N₂O BACT

9.2.3.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

N₂O catalysts have been used in nitric/adipic acid plant applications to minimize N₂O emissions.¹⁴ Tailgas from the nitric acid production process is routed to a reactor vessel with a N₂O catalyst followed by ammonia injection and a NO_x catalyst.

Low NO_x burner technology selection and energy efficient operating practices are additionally available control technology options for N₂O reduction.

9.2.3.2 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

N₂O catalysts have not been used to control N₂O emissions from cracking furnace applications. In addition, the N₂O concentrations present in the exhaust stream would make installation of N₂O catalysts technically infeasible. In comparison, the application of a catalyst in the nitric acid industry sector has been effective due to the high (1,000-2,000 ppm) N₂O concentration in those exhaust streams. N₂O catalysts are eliminated as a technically feasible option for the proposed project.

With N₂O catalysts eliminated, low-NO_x, efficient burner technology selection and energy efficient operating practices are the only available and technically feasible control options for N₂O reduction from the furnaces.

9.2.3.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

Low-NO_x, high efficiency burner selection and energy efficient operating practices are evaluated in the remaining steps of the N₂O BACT analysis for the furnaces. It is unclear which option has a more significant impact on emissions of N₂O from the facility and Equistar intends to employ both options concurrently. Therefore, no ranking of control options is performed.

¹⁴ http://www.catalysts.basf.com/Main/mediaroom/10years_worldscale_experience_in_reducing_nitrous.be

9.2.3.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The most efficient, technically feasible control options to reduce N₂O emissions involve installation of low-NO_x high efficiency natural gas burners and use of energy efficient practices. Both options will be employed by Equistar.

9.2.3.5 SELECTION OF N₂O BACT (STEP 5)

Equistar will select efficient, low-NO_x natural gas burners that meet the design requirements for the proposed project and is implementing the energy efficiency efforts as described in Section 9.2.1.5. Through these efforts to maximize the unit's efficiency, N₂O emissions from the furnaces are inherently reduced and kept to a minimum.

9.3 CRACKING FURNACE DECOKE STACK – CO₂ BACT DISCUSSION

9.3.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Decoking is a process of removing coke deposits from the interior of process tubes in the furnace. This is a combustion process with CO and CO₂ being a product of that combustion. The gases are emitted via a drum that is used to remove particulates.

Control of air in the decoking process to low levels to drive the reaction to predominately CO would reduce emissions of CO₂ while increasing emissions of CO.

Review of the RBLC identified no BACT level control for GHG emissions from decoking operations. Because coke deposits in furnace tubes reduce furnace efficiency, great effort is incorporated in the design and operation of furnaces to minimize the amount of coke that is required to be removed. This alone is a limitation of CO₂ emissions. No methods have been identified for practical control of the CO₂ emissions other than to design and operate the furnaces to minimize the need for decoking.

9.3.2 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

While the limitation of air in the decoking process would drive reaction kinetics to favor CO generation, such a move is environmentally detrimental. Therefore this option is rejected as technically infeasible.

There are no known control options for CO₂ from decoking operations beyond the proper design and operation of the furnaces to minimize the amount of coke to be burned. This is a technically feasible option for overall reduction of CO₂ emissions.

9.3.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

Only a single option remains for control of CO₂ from decoking operation, that being the careful design and operation of the furnace to limit the need for decoking and its associated emissions of CO₂.

9.3.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

Only a single option remains for control of CO₂ from decoking operation, that being the careful design and operation of the furnace to limit the need for decoking and its associated emissions of CO₂.

9.3.5 SELECTION OF CO₂ BACT (STEP 5)

Equistar will utilize a combination of design and furnace operation that limits build-up of coke in the process tubes, thus limiting the need for decoking. By minimizing decking, CO₂ emissions are also minimized.

9.4 FLARES – GHG BACT

9.4.1 FLARES - CO₂ BACT EVALUATION

CO₂ emissions from flaring process gas are produced from the combustion of carbon-containing compounds (e.g., CO, VOCs, CH₄) present in the process gas streams and the pilot fuel. CO₂ emissions from the flare are based on the estimated flow rates of flared carbon-containing gases derived from heat and material balance data.

The flares are examples of control devices in which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, the control of CH₄ in the process gas at the flare results in the creation of additional CO₂ emissions via the combustion reaction mechanism. However, given the relative GWPs of CO₂ and CH₄ and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to CH₄ emissions even though it will form additional CO₂ emissions.¹⁵

9.4.1.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

The following potential CO₂ control strategies for the flares were considered as part of this BACT analysis:

- ▲ Carbon capture and storage (CCS)
- ▲ Flare Gas Recovery
- ▲ Good Flare Design

9.4.1.1.1 CARBON CAPTURE AND SEQUESTRATION

A detailed discussion of the feasibility and availability of CCS technology is provided in Section 9.2.1.1.1. The primary source of CO₂ emissions from the flares is combustion of CH₄ and VOC present in the process gas. With no ability to collect exhaust gas from a flare other than using an enclosure, post combustion capture is not an available control option, and pre-combustion capture has not been demonstrated for removal of CO₂ from

¹⁵ For example, combusting 1 lb of CH₄ (21 lb CO₂e) at the flare will result in 0.02 lb CH₄ and 2.7 lb CO₂ (0.02 lb CH₄ x 21 CO₂e/CH₄ + 2.7 lb CO₂ x 1 CO₂e/CO₂ = 2.9 lb CO₂e), and therefore, on a CO₂e emissions basis, combustion control of CH₄ is preferable to venting the CH₄ uncontrolled.

intermittent and dilute process gas streams routed to a flare. Furthermore, even if pre-combustion capture were available, the limiting factor is the availability of a mechanism (pipeline or geologic formation) at this time for the facility to permanently sequester the captured gas. Since CCS is not considered an available technology, it has been eliminated from further consideration in the remaining steps of the analysis.

9.4.1.1.2 FLARE GAS RECOVERY

Flaring can be reduced by installation of commercially available recovery systems, including recovery compressors and collection and storage tanks. The recovered gas is then utilized by introducing it into the fuel system as applicable. However, it is important to note the maintenance, startup, and shutdown streams sent to the flares is a waste stream that cannot be routed to the fuel gas system or to a process unit due to its composition and variability. Therefore, it is technically infeasible to re-route the flare gas to a process fuel system and hence, the gas will be combusted by the flare for control.

9.4.1.1.3 GOOD FLARE DESIGN

Good flare design can be employed to destroy large fractions of the flare gas. Much work has been done by flare and flare tip manufacturers to assure high reliability and destruction efficiencies. Good flare design includes pilot flame monitoring, flow measurement, and monitoring/control of waste gas heating valve.

9.4.1.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Installing a flare gas recovery system to recover flare gas to the fuel gas system is considered a feasible control technology for industrial flares; however as stated above, the composition of the flare gas produced by this project is unsuitable for the gas to be rerouted into the process or to a fuel stream. For this project, flare gas recovery is infeasible.

Use of a good flare design with appropriate instrumentation and control is a demonstrated and available option.

9.4.1.3 STEP 3 – RANK REMAINING CONTROL OPTIONS BY EFFECTIVENESS

Use of a good flare design with appropriate instrumentation and control is the only remaining option. Natural gas-fired pilots and good flare design will be applied as CO₂ GHG BACT for the flares in order to minimize emissions from the flares.

9.4.1.4 STEP 4 – TOP-DOWN EVALUATION OF CONTROL OPTIONS

No significant adverse energy or environmental impacts (that would influence the GHG BACT selection process) associated with operating a flare to control process gas or using good flare design are expected.

9.4.1.5 STEP 5 – SELECT CO₂ BACT FOR FLARE

Use of a good flare design with appropriate instrumentation and control is the only remaining option. Natural gas-fired pilots and good flare design will be applied as CO₂ GHG BACT for the flares in order to minimize emissions from the flares.

9.4.2 FLARES - CH₄ BACT EVALUATION

Contributions to CH₄ emissions from the flares include:

- Incomplete combustion of CH₄ in the process gas and supplemental natural gas fuel, and
- CH₄ formed as a byproduct of incomplete hydrocarbon combustion from the flare pilots.

Primary CH₄ emissions are calculated based on the CH₄ content of flared process gas and supplemental natural gas fuel and the CH₄ combustion efficiency for a well-designed flare. Secondary CH₄ emissions from incomplete combustion of non-CH₄ hydrocarbons in the pilot gas are calculated based on the MRR emission factor for CH₄ from natural gas combustion. In general, completeness of combustion and CH₄ emissions from a flare is governed by flame temperature, residence time in the combustion zone, turbulent mixing of the components to complete the oxidation reaction, and available oxygen for free radical formation.¹⁶

9.4.2.1 STEP 1 – IDENTIFY AVAILABLE CONTROL OPTIONS

The following potential CH₄ control strategies for the flares were considered as part of this BACT analysis:

- ▲ Good Flare Design
- ▲ Flare Gas Recovery

9.4.2.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Use of a good flare design is considered feasible. As stated above the variability of the flare gas makes it infeasible to consider flare gas recovery for this project.

9.4.2.3 STEP 3 – RANK REMAINING CONTROL OPTIONS BY EFFECTIVENESS

The only feasible option from Step 2 for minimizing CH₄ emissions from the flares will be applied; that being the use of an existing good flare design.

9.4.2.4 STEP 4 – TOP-DOWN EVALUATION OF CONTROL OPTIONS

Only one feasible option remains. That option is the use of a properly designed, operated, instrumented, and controlled flare.

¹⁶ U.S. EPA, Office of Air Quality Planning and Standards. *OAQPS Control Cost Manual*, 6th edition. Section 3.2 – Chapter 1. EPA 452/B-02-001. Research Triangle Park, NC. January 2002.

9.4.2.5 STEP 5 – SELECT CH₄ BACT FOR FLARE

Equistar is proposing to use an existing properly designed and operated flare for control of waste gas emissions. The flare will meet the requirements of 40 CFR §60.18, and will be properly instrumented and controlled.

9.4.3 FLARE - N₂O BACT EVALUATION

Process gas routed to the flares will not contain N₂O. Since the flares are required to safely dispose of process gas and to meet BACT requirements for criteria pollutant emissions. Emissions of N₂O generated by the flares are negligible and are therefore deemed not technically or economically feasible for further application of controls.

9.5 GHG BACT EVALUATION FOR FUGITIVE EMISSIONS

9.5.1 CH₄ BACT EVALUATION

GHG emissions from leaking pipe components (fugitive emissions) in the proposed project include CH₄. The following section proposes appropriate GHG BACT emission limitations for fugitive CH₄ emissions.

9.5.1.1 STEP 1 – IDENTIFY ALL CONTROL TECHNOLOGIES

In determining whether a technology is available for controlling GHG emissions from fugitive components, permits and permit applications and US. EPA's RBLC were consulted. Based on these resources, the following available control technologies were identified:

- ▲ Installation of leakless technology components to eliminate fugitive emission sources.
- ▲ Implementing various LDAR programs in accordance with applicable state and federal air regulations.
- ▲ Implement alternative monitoring using a remote sensing technology such as infrared camera monitoring.
- ▲ Implementing an audio/visual/olfactory (AVO) monitoring program for compounds.
- ▲ Design and construct facilities with high quality components, with materials of construction compatible with the process.

9.5.1.2 STEP 2 – TECHNICAL FEASIBILITY ANALYSIS

Leakless technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used. These technologies are generally considered cost prohibitive except for specialized service. Some solutions, such as bellows valves, if they fail, cannot be repaired without a unit shutdown that often generates additional emissions.

LDAR programs have traditionally been developed for control of VOC emissions. BACT determinations related to control of VOC emissions rely on economic reasonableness for these instrumented programs. The adverse impact of fugitive emissions of CH₄ due to its global warming potential has not been quantified, and no reasonable cost effectiveness has been determined. Instrumented monitoring is technically feasible for components in CH₄ service.

Remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbons.

Leaking components can be identified through AVO methods. Some of the fuel gases and process fluids in the olefins unit are expected to have discernable odor, making them detectable by olfactory means. A large leak can be detected by sound (audio) and sight. The visual detection can be a direct viewing of leaking gases, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. AVO programs are common and in place in industry.

A key element in control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. For example, a valve that has been manufactured under high quality conditions can be expected to have lower runout on the valve stem and the valve stem is typically polished to a smoother surface. Both of these factors greatly reduce the likelihood of leaking. The olefins unit at Equistar's La Porte plant utilizes such components, and materials of construction, including gasketing that is compatible with the service in which they are employed.

9.5.1.3 STEP 3 – RANKING OF REMAINING CONTROL TECHNOLOGIES BY EFFECTIVENESS

Leakless technologies are highly effective in eliminating fugitive emissions from the specific interface where installed, however leak interfaces remain even with leakless technology components in place. In addition the sealing mechanism, such as a bellows, is not repairable online and may leak in the event of a failure until the next unit shutdown. This is the most effective of the controls.

Instrumented monitoring can identify leaking CH₄, making identification of components requiring repair possible.

Remote sensing using infrared imaging has proven effective for identification of leaks. The process has been the subject to EPA rulemaking for an alternative monitoring method to Method 21. Effectiveness is likely comparable to EPA Method 21 with cost being included in the consideration.

Audio/Visual/Olfactory means of identifying leaks owes its effectiveness to the frequency of observation opportunities. Those opportunities arise as operating technicians make rounds, inspecting equipment during those routine tours of the operating areas. This

method cannot generally identify leaks at as low a leak rate as instrumented reading can identify; however low leak rates have lower potential impacts than do larger leaks. This method, due to frequency of observation is effective for identification of larger leaks.

Use of high quality components is effective in preventing emissions of GHGs, relative to use of lower quality components.

9.5.1.4 STEP 4 – TOP-DOWN EVALUATION OF CONTROL OPTIONS

Recognizing that leakless technologies have not been universally adopted as LAER or BACT, even for toxic or extremely hazardous services, it is reasonable to state that these technologies are impractical for control of GHG emissions whose impacts have not been quantified. Any further consideration of available leakless technologies for GHG controls is unwarranted.

The use of instrumented leak detection is technically feasible, however the effectiveness in comparison to the infrared monitoring, based on EPA's presentation of the infrared monitoring as an acceptable alternative, is that they are likely similar. However cost and expediency of the infrared monitoring makes it a more cost effective method.

The infrared monitoring has much lower cost than Method 21 instrumented monitoring and, based on EPA adoption of this remote sensing as an acceptable alternative to Method 21 monitoring, this option is preferred over instrumented Method 21 monitoring.

The AVO monitoring option is believed to be effective in finding larger leaks and has low cost due to being incorporated into routine operations.

Design to incorporate high quality components is effective in proving longer term emissions control.

9.5.1.5 STEP 5 – SELECT CH₄ BACT FOR FUGITIVE EMISSIONS

Equistar proposes to conduct remote sensing for detection of leaks for those pipeline sized fugitive emissions components that are in methane service and not required to be monitored via instrumented Method 21 monitoring by another permit or rule.

10. MATERIAL BALANCE

TABLE 2

MATERIAL BALANCE

This material balance table is used to quantify possible emissions of air contaminants and special emphasis should be placed on potential air contaminants, for example: If feed contains sulfur, show distribution to all products. Please relate each material (or group of materials) listed to its respective location in the process flow diagram by assigning point numbers (taken from the flow diagram) to each material.

LIST EVERY MATERIAL INVOLVED IN EACH OF THE FOLLOWING GROUPS	Point No. from Flow Diagram	Process Rate (lbs/hr or SCFM) standard conditions: 70 °F 14.7 PSIA. Check appropriate column at right for each process.	Measurement	Estimation	Calculation
1. Raw Materials - Input					
Ethane, Propane, Butane, Natural Gasoline, Natural Gas Liquids, and Liquefied Petroleum Gas Import Propylene	1	1,080,000 lb/hr			X
	2	90,000 lb/hr			X
2. Fuels - Input					
Fuel Gas and/or Natural Gas	3	2.6 MMSCf/hr		X	
3. Products & By-Products - Output					
Ethylene	4	682,000 lb/hr			X
Propylene	5				X
Acetylene	6				X
Mixed C4's	7				X
Debutanized Aromatic Concentrate (DAC)	8				X
Hydrogen	9				X
Fuel Oil	10				X
4. Solid Wastes - Output					
Coke		50 tons/yr 770,000 lbs every 2 years 174,500 lbs every 4 years		X	
Spent Desiccant				X	
Spent Catalysts				X	
5. Liquid Wastes - Output					
Wastewater Effluent		320,000 lb/hr (average)		X	
6. Airborne Waste (Solid) - Output					
Coke Fines		See Table 1a			X
7. Airborne Wastes (Gaseous) - Output					
PM		See Table 1a			X
NOx					X
CO					X
SO2					X
VOC					X

10/93

EMISSION CALCULATIONS

Equistar Chemicals, L.P.
La Porte Site
QE-1 Expansion
18978 and 83822

GHG Emission Factors - Natural Gas Combustion

Greenhouse Gas	Global Warming Potential ¹	Emission Factor ²	
		(kg/MMBtu)	
CO ₂	1	53.02	
CH ₄	21	1.0E-03	
N ₂ O	310	1.0E-04	

¹ Per 40 CFR Part 98 dated July 12, 2010, Table A-1 of Subpart A - Global Warming Potentials (100-year time horizon), used to convert emissions of each GHG to a CO₂ equivalent basis.

² Per 40 CFR Part 98 dated December 17, 2010, Table C-1 of Subpart C - Default CO₂ Emission Factors and High Heat Values for Various Types of Fuel and Table C-2 of Subpart C - Default CH₄ and N₂O Emission Factors for Various Types of Fuel. Emission factors for natural gas (unspecified heat value, weighted U.S. average) are used.

GHG Emission Rates from Natural Gas Combustion

Heat Input Capacity ¹ (MMBtu/hr)	Maximum Annual Operation (hr/yr)	Number of New Furnaces	CO ₂ Emissions ³		CH ₄ Emissions ³		N ₂ O Emissions ³		Total Emissions	
			(MTCE/yr) ²	(tpy)	(MTCE/yr) ²	(tpy)	(MTCE/yr) ²	(tpy)	(MTCE/yr)	(tpy)
471	8,760	3	656,553.87	723,522.37	260.05	13.65	383.88	1.36	657,197.79	723,537.38

¹ Annual Average Heat Input Capacity is assumed to be 80% of the maximum rated capacity (589 MMBtu/hr) for the furnace.

² MTCE - Metric tons (tonne) of carbon dioxide equivalent

³ Sample Calculation for CO₂ emissions:

$$\text{CO}_2 \text{ Emission Rate (MTCE/yr)} = (\text{Emission Factor (kg/mmBtu)} * (\text{Global Warming Potential}) * (\text{Heat Input Capacity (MMBtu/hr)} * (\text{Maximum Annual Operation (hr/yr)})) * (0.001 \text{ tonne/kg}))$$

$$\text{CO}_2 \text{ Emission Rate (tpy)} = (\text{CO}_2 \text{ Emission Rate (MTCE/yr)} * (1.102 \text{ ton/tonne}))$$

$$\text{CO}_2 \text{ Emission Rate (tpy)} = \frac{656,553.87 \text{ MTCE}}{\text{yr}} * 1.102 \text{ ton/tonne} = 723,522 \text{ ton/yr}$$

Equistar Chemicals, L.P.
La Porte Site
QE-1 Expansion
18978 and 83822

EPN: QE1416FB
FIN: QE1416FB

GHG Emission Rates from Decoking

Calculation Basis	
Number of Decoke per year	26
Number of Furnaces	3
CO Emission Factor	6233 lb/decoke
Amount of coke burned results in CO ₂ :	75.00 mol%
Amount of coke burned results in CO:	25.00 mol%

Greenhouse Gas	Emission Factor lb/decoke ¹	Global Warming Potential ²	Emission Rate	
			(tpy)	(MTCE/yr) ³
CO ₂	29,386	1	1,146	1,040
CH ₄	N/A	21	N/A	N/A
N ₂ O	N/A	310	N/A	N/A

¹ CO₂ Emission Factor (lb/decoke) = 6233lb = 29,386 lb/decoke

decoke	mol of CO	44 lb
		= 29,386 lb/decoke

² Per 40 CFR Part 98 dated July 12, 2010, Table A-1 of Subpart A - *Global Warming Potentials (100-year time horizon)*, used to convert emissions of each GHG to a CO₂ equivalent basis.

³ CO₂ Emission Rate (MTCE/yr) = $\frac{1146.04 \text{ ton}}{\text{yr}} \times \frac{1 \text{ kg CO}_2\text{e}}{\text{kg CO}_2} \times \frac{1 \text{ ton}}{1.102 \text{ tonne}} = 1039.97 \text{ MTCE/yr}$

Equistar Chemicals, L.P.

La Porte Site

QE-1 Expansion

18978 and 83822

EPN: QEFUG

FIN: QEFUG

Greenhouse Gas	Global Warming Potential ¹
CO ₂	1
CH ₄	21
N ₂ O	310

GHG Emission Rates from Fugitives

Greenhouse Gas	Emission Rate	
	(tpy)	(MTCE/yr) ²
CO ₂	N/A	N/A
CH ₄	68.59	1307.11
N ₂ O	N/A	N/A

¹ Per 40 CFR Part 98 dated July 12, 2010, Table A-1 of Subpart A - Global Warming Potentials (100-year time horizon); used to convert emissions of each GHG to a CO₂ equivalent basis.

² MTCE - Metric tons (tonne) of carbon dioxide equivalent.

Sample Calculation for CH₄ emissions:

$$\text{CH}_4 \text{ Emission Rate (MTCE/yr)} = \frac{\text{Emission Rate (ton/yr)} * (\text{Global Warming Potential}) * (1 \text{ tonne} / 1.102 \text{ tonne})}{1 \text{ ton}} = 1307.11 \text{ MTCE/yr}$$

$$\text{CH}_4 \text{ Emission Rate (MTCE/yr)} = \frac{68.59 \text{ ton}}{\text{yr}} * \frac{21 \text{ kg CO}_2\text{e}}{\text{kg CO}_2} = 1,102 \text{ tonne}$$

GHG Emissions

	Calculation Basis ¹	
	QE3050B	QE8050B
Annual CH ₄ Vent Rate	1,624,004	8,673,105 lb/yr
Annual Carbon to Flare	3,309,648	17,851,092 lb/yr
Annual Vent Stream Heating Value	88,007	466,255 MMBtu/yr
Global Warming Potential ²		
CH ₄	21	kg CO ₂ e/kg component
CO ₂	1	kg CO ₂ e/kg component

¹ Data from MSS permit application and updated based on new total volume of equipment to flare.

² Per 40 CFR Part 98 dated July 12, 2010, Table A-1 of Subpart A - *Global Warming Potentials (100-year time horizon)*, used to convert emissions of each GHG to a CO₂ equivalent basis.

Flare	Component	Annual Vent Rate	Flare DRE ¹	Emission Rate ²	
		(lb/yr)	(%)	(tpy)	(MTCE/yr)
QE3050B	CH ₄	1,624,004	99.5%	4.06	77.35
	CO ₂		0%	6,037	5,477
QE8050B	CH ₄	8,673,105	99.5%	21.68	413.08
	CO ₂		0%	32,563	29,541
Total Emissions =				38,626.46	35,508.40

¹ Previously documented and TCEQ approved DRE of Main Flare and ARU Flare.

² Emission Rate CH₄ (tpy) = (Annual Vent to Flare [lb/yr])*(1-Flare DRE [%])/(2000 lb/ton)

Emission Rate CO₂ (tpy) = (Annual Carbon to Flare [lb/yr])*(Flare DRE [%])*(44 lb/lbmol CO₂/12 lb/lbmol C)/(2000 lb/ton)

Emission Rate (MTCE/yr) = (Emission Rate [tpy])*(Global Warming Potential)/(1.102 ton/tonne)