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Application for Prevention of Significant Deterioration Greenhouse Gas Emissions Air Permit Olefins Plant Expansion Project

Equistar Chemicals, LP
Corpus Christi Complex
Corpus Christi, Texas

RN100221662
CN 600124705

STATE OF TEXAS
J L MONTGOMERY
51616
LICENSED
PROFESSIONAL ENGINEER

March 2013

RPS
TBPE No. 1298

J L Montgomery
3/6/2013

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Section 1
Introduction

Equistar Chemicals, LP (Equistar) operates a petrochemical manufacturing plant located in Corpus Christi, Nueces County. The petrochemical manufacturing plant consists of two chemical production units, the butadiene unit and the olefins and aromatics unit. There is also a cogeneration unit at the site. The olefins and aromatics unit is commonly referred to as the Olefins Plant. Equistar is proposing to expand Olefins Plant production and is requesting regulatory air permit authorization for the planned construction.

1.1 Background and Permit History

Recent advances in drilling techniques and shale oil production is positive news for the United States economy in general and petrochemical manufacturers in particular, who have benefited from the increased availability of ethane feed stocks and lower energy costs that in turn lower overall chemical production costs. These factors have resulted in numerous announcements from US companies concerning recent plans to move forward with various projects including ethane cracking projects, which has further benefited both employment and economic recovery in the United States.

Equistar's Olefins Plant is authorized for new source review (NSR) purposes by Texas Commission on Environmental Quality (TCEQ) Permit No. 4682B/PSD-TX-761-M2, which was most recently renewed on February 10, 2012. The maintenance, startup, and shutdown (MSS) activities associated with the Olefins Plant are authorized by Permit No. 83864.

1.2 Purpose of This Permit Application

Equistar proposes to expand its Olefins Plant production by increasing maximum furnace firing rates and changing the tubing configuration of seven (7) cracking U.S.C. furnaces (EPNs 1C, 1D, 1E, 1F, 1G, 1H, 1J), which will trigger NSR requirements. The purpose of this application is to authorize the following Olefins Plant Expansion Project changes and associated emissions:

- Increase maximum firing rates of four (4) cracking U.S.C. furnaces from 153 MMBtu/hr to 188 MMBtu/hr each (HHV) (EPNs 1A, 1B, 1K, and 1L);
- Increase VMR furnace A & B maximum firing rates from 93 MMBtu/hr to 126.7 MMBtu/hr each (HHV) (EPNs 3A and 3B);

- Revise the tubing configurations of seven (7) cracking U.S.C. furnaces and increase maximum firing rates from 153 MMBtu/hr to 290 MMBtu/hr each (HHV) (EPNs 1C, 1D, 1E, 1F, 1G, 1H, 1J);

- Increase maximum firing rates of two (2) U.S.C. furnaces from 260 MMBtu/hr to 290 MMBtu/hr each (HHV) (EPNs 1M and 1N);

- Increase maximum firing rates for two (2) steam super heaters from 67 MMBtu/hr to 146 MMBtu/hr each (HHV) (EPNs 5A and 5B);

- Enable the use of higher hydrogen fuel gas for combustion heat, but retain the ability to use low hydrogen fuel gas, by installing new ultra-low NO_x burners in all fifteen (15) cracking furnaces (EPNs 3A, 3B, 1A through 1H and 1J through 1N) and the two (2) steam super heaters (EPNs 5A and 5B);

- Install a new Demethanizer Tower, Residue Gas Rectifier, and Acetylene Converter to enable the processing of the increased quantity of cracked gas;

- Addition of associated process drums;

- Addition of fugitive components (necessary valves, connectors, pumps, compressors, etc.); and

- Addition of cooling tower cells.

Appendix A, Table A-1 contains a summary of the proposed increases in carbon dioxide equivalent (CO_2e) emissions associated with the planned Olefins Plant Expansion Project. The proposed increase exceeds the 75,000 tpy CO_2 equivalent (CO_2e) PSD significance threshold, which will trigger PSD requirements for GHG emissions that are currently being administered by EPA Region VI.

In order to obtain the required Olefins Plant Expansion Project New Source Review (NSR) air permit authorizations, Equistar is submitting a criteria pollutant PSD application to TCEQ and GHG PSD application to EPA for the proposed Olefins Plant Expansion Project. A copy of the criteria pollutant Permit No. 4682B/PSD-TX-761-M2 amendment application submitted to TCEQ on March 1, 2013 is enclosed in Appendix C solely for reference purposes. The remainder of the enclosed documentation is a PSD application that is intended to permit the Olefins Plant Expansion Project GHG emissions.

1.3 How This Application is Organized

This document constitutes Equistar's GHG PSD permit application and request for an EPA PSD permit to authorize GHG emissions from the planned Olefins Plant project. Because EPA has not developed application forms for GHG permitting, TCEQ forms are used where deemed appropriate. The application is organized as follows:

Section 1 identifies the project for which authorization is requested and presents the application document organization.

Section 2 contains administrative information and completed Federal NSR applicability Tables 1F and 2F.

Section 3 contains an area map showing the facility location and a plot plan showing the location of each emission point with respect to the plant fence line.

Section 4 contains more details about the proposed modifications and changes in operation, as well as a brief process description and process flow diagrams.

Section 5 describes the basis of the calculations for the project GHG emissions and includes the proposed GHG emission limits.

Section 6 includes an analysis of best available control technology for the new and modified sources of GHG emissions.

Section 7 contains a federal NSR applicability discussion and analyses.

Appendix A contains GHG emissions calculations for new, modified or affected project emission equipment.

Appendix B contains the results of an RBLC database search for GHG controls employed on new and modified GHG emission sources.

Appendix C contains a copy of the TCEQ air permit application for the project.

Section 2
Administrative Information and TCEQ Forms

This section contains the following forms:

- Administrative Information;
- TCEQ Table 1F; and
- TCEQ Table 2F.

Tables 1F and 2F are federal NSR applicability forms. Equistar recognizes that the planned Olefins Plant Expansion Project will trigger PSD requirements for GHG emissions, so an emissions netting Table 3F for the contemporaneous period is not required and has not been included in the enclosed application. Because this application covers only GHG emissions, and PSD permitting of other pollutants is being conducted by TCEQ, these forms only include GHG emissions for new, modified or affected project sources. Detailed PSD applicability information for the project GHG emissions is presented on Tables 1F and 2F and in Section 7.

Administrative Information

A. Company or Other Legal Name: Equistar Chemicals, LP		
B. Company Official Contact Name (☒ Mr. ☐Mrs. ☐Ms. ☐Dr.): Randal Tatum		
Title: Plant Manager		
Mailing Address: 1501 McKinzie Road		
City: Corpus Christi	State: TX	ZIP Code: 77410
Telephone No.: 361-242-8075	Fax No.: 361-242-8003	E-mail Address: Randal.Tatum@lyondellbasell.com
C. Technical Contact Name: H. Scott Peters		
Title: Environmental Engineer		
Company Name: Equistar Chemicals, LP		
Mailing Address: 1501 McKinzie Road		
City: Corpus Christi	State: TX	ZIP Code: 77410
Telephone No.: 361-242-5028	Fax No.: 361-242-8030	E-mail Address: Howard.Peters@lyondellbasell.com
D. Facility Location Information:		
Street Address: 1501 McKinzie Road		
If no street address, provide clear driving directions to the site in writing:		
City: Corpus Christi	County: Nueces	ZIP Code: 77410
E. TCEQ Account Identification Number (leave blank if new site or facility): NE-0051-B		
F. TCEQ Customer Reference Number *(leave blank if unknown):* CN600124705		
G. TCEQ Regulated Entity Number *(leave blank if unknown)*: RN100221662		
H. Site Name: Corpus Christi Operations (CCO)		
I. Area Name/Type of Facility: Olefins Unit	☒ Permanent ☐ Portable	
J. Principal Company Product or Business: Petrochemical		
K. Principal Standard Industrial Classification Code: 2869		
L. Projected Start of Construction Date: 6/02/2014	Projected Start of Operation Date: 11/2/14 to 5/9/15	
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.		
NAME: Randal Tatum		
SIGNATURE:____ *Original Signature Required*		
DATE:		

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: TBD	Application Submittal Date:	March 6, 2013
Company: Equistar Chemicals LP		
RN: 100221662	Facility Location: Corpus Christi	
City: Corpus Christi	County: Nueces	
Permit Unit I.D.: TBD	Permit Name: Olefins Plant GHG Permit	
Permit Activity: New Source___ Modification_X_		
Project or Process Description: Olefins Plant Expansion		

Complete for all Pollutants with a Project Emission Increase.	POLLUTANTS								
	Ozone		CO	PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	Other[1] CO_2e
	VOC	NO_x							
Nonattainment? (yes or no)	NA	NA	NA	NA	NA	NA	NA	NA	No
PSD?	NA	NA	NA	NA	NA	NA	NA	NA	Yes
Existing site PTE (tpy)?									>100,000
Proposed project emission increases (tpy from 2F)[3]									1,059,332
Is the existing site a major source? [2]If not, is the project a major source by itself?	NA	NA	NA	NA	NA	NA	NA	NA	Yes
Significance Level (tpy)									75,000
If netting required, estimated start of construction?	June 2, 2014								
Five years prior to start of construction	June 2, 2009								contemporaneous
Estimated start of operation	November 2, 2014 to May 9, 2015								period
Net contemporaneous change, including proposed project, from Table 3F. (tpy)									NA
Major NSR Applicable?	NA	NA	NA	NA	NA	NA	NA	NA	Yes

1 Other PSD pollutants. [CO_2e, Pb, H_2S, TRS, H_2SO_4, Fluoride excluding HF, ect.]
2 Sum of proposed emissions minus baseline emissions, increases only.

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

Signature Title

TABLE 2F
PROJECT EMISSION INCREASE

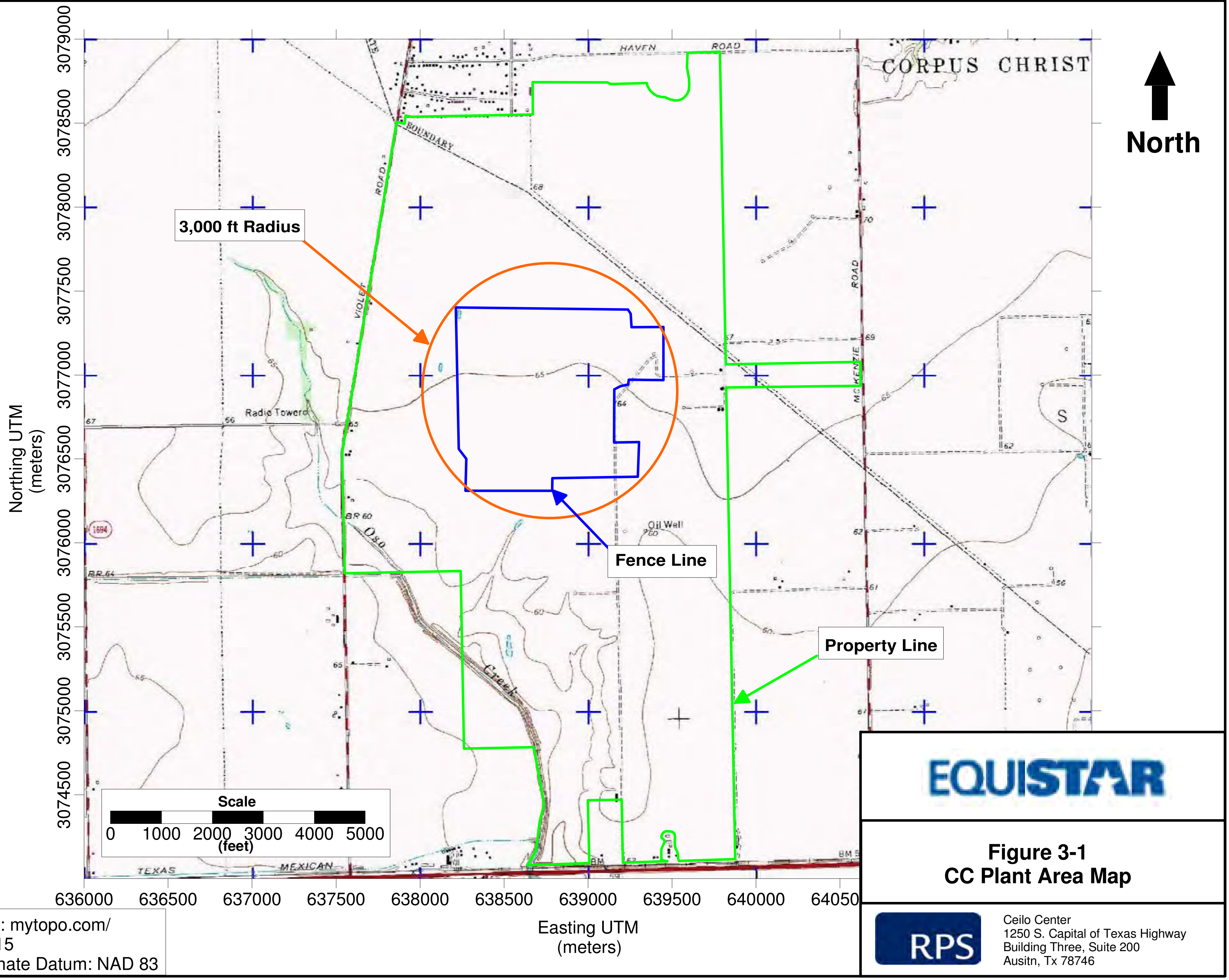
Pollutant[1]:	**CO_2 Equivalent**	**Permit No.:**	**TBD**
Baseline Period:	**1/1/2010**	**to**	**12/31/2011**

	Affected or Modified Facilities[2]			Permit No.	Actual Emissions[3] (tons/yr)	A Baseline Emissions[4] (tons/yr)	B Proposed Emissions[5] (tons/yr)	Projected Actual Emissions	Difference (B-A)[6]	Correction[7] (tons/yr)	Project Increase[8] (tons/yr)
	FIN	EPN	Facility Name								
1	1A	1A	U.S.C. FURNACE “A”	TBD	55,395	55,395	94,290		38,895		38,895
2	1B	1B	U.S.C. FURNACE “B”	TBD	53,619	53,619	94,290		40,671		40,671
3	1C	1C	U.S.C. FURNACE “C”	TBD	54,997	54,997	145,448		90,451		90,451
4	1D	1D	U.S.C. FURNACE “D”	TBD	53,711	53,711	145,448		91,737		91,737
5	1E	1E	U.S.C. FURNACE “E”	TBD	57,092	57,092	145,448		88,356		88,356
6	1F	1F	U.S.C. FURNACE “F”	TBD	60,571	60,571	145,448		84,877		84,877
7	1G	1G	U.S.C. FURNACE “G”	TBD	58,418	58,418	145,448		87,030		87,030
8	1H	1H	U.S.C. FURNACE “H”	TBD	54,607	54,607	145,448		90,841		90,841
9	1J	1J	U.S.C. FURNACE “J”	TBD	55,960	55,960	145,448		89,488		89,488
10	1K	1K	U.S.C. FURNACE “K”	TBD	60,154	60,154	94,290		34,136		34,136
11	1L	1L	U.S.C. FURNACE “L”	TBD	55,650	55,650	94,290		38,641		38,641
12	1M	1M	U.S.C. FURNACE “M”	TBD	78,898	78,898	145,448		66,550		66,550
13	1N	1N	U.S.C. FURNACE “N”	TBD	65,342	65,342	145,448		80,106		80,106
14	3A	3A	V.M.R. FURNACE “A”	TBD	39,403	39,403	63,546		24,143		24,143
15	3B	3B	V.M.R. FURNACE “B”	TBD	41,688	41,688	63,546		21,858		21,858
16	5A	5A	STEAM S. HEATER “A”	TBD	30,249	30,249	73,025		42,776		42,776
17	5B	5B	STEAM S. HEATER “B”	TBD	27,138	27,138	73,025		45,887		45,887
18	9A	9A	SOUTH DECOKING	TBD	127	127	724		597		597
19	9B	9B	NORTH DECOKING	TBD	121	121	545		424		424
20	FUG	FUG	Fugitive Emissions	TBD			190		190		190
21	MSS	MSS	Flare MSS Emissions	TBD			1,678		1,678		1,678
										Page Subtotal[9]:	**1,059,332**

1. Individual Table 2F=s should be used to summarize the project emission increase for each criteria pollutant.
2. Emission Point Number as designated in NSR Permit or Emissions Inventory.
3. All records and calculations for these values must be available upon request.
4. Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.
5. If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplement.
6. Proposed Emissions (column B) Baseline Emissions (column A).
7. Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement.
8. Obtained by subtracting the correction from the difference. Must be a positive number.
9. Sum all values for this page.
10. Underlying data in this table may not be accurate to the apparent number of significant digits.

Section 3
Area Map and Plot Plan

An Area Map showing the location of the Olefins Production Plant is presented in Figure 3-1. A plot plan showing the location of Olefins Plant Expansion Project emission equipment with GHG emissions is presented in Figure 3-2.



Source: mytopo.com/
Zone: 15
Coordinate Datum: NAD 83

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Figure 3-1
CC Plant Area Map

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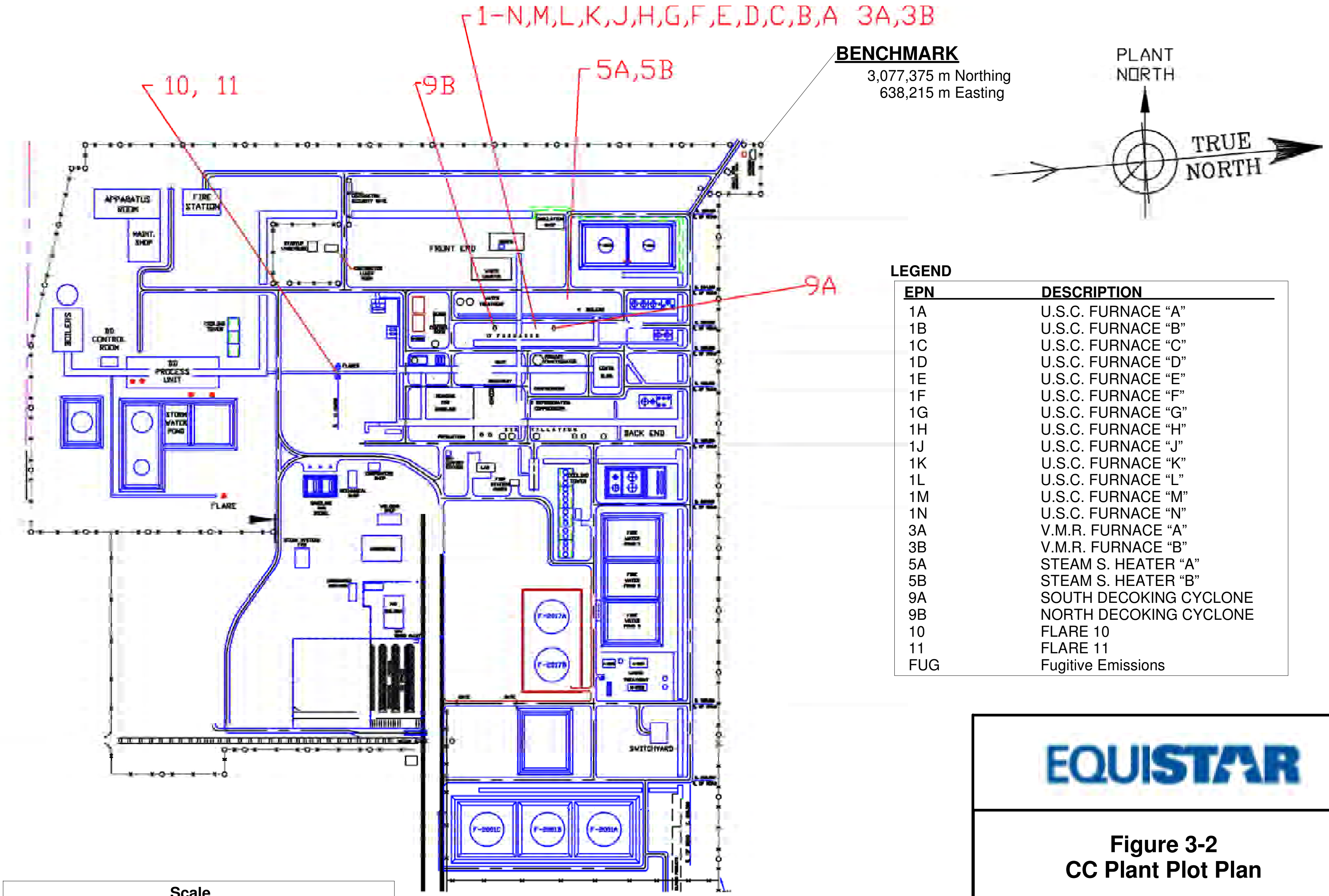

LEGEND

EPN	DESCRIPTION
1A	U.S.C. FURNACE “A”
1B	U.S.C. FURNACE “B”
1C	U.S.C. FURNACE “C”
1D	U.S.C. FURNACE “D”
1E	U.S.C. FURNACE “E”
1F	U.S.C. FURNACE “F”
1G	U.S.C. FURNACE “G”
1H	U.S.C. FURNACE “H”
1J	U.S.C. FURNACE “J”
1K	U.S.C. FURNACE “K”
1L	U.S.C. FURNACE “L”
1M	U.S.C. FURNACE “M”
1N	U.S.C. FURNACE “N”
3A	V.M.R. FURNACE “A”
3B	V.M.R. FURNACE “B”
5A	STEAM S. HEATER “A”
5B	STEAM S. HEATER “B”
9A	SOUTH DECOKING CYCLONE
9B	NORTH DECOKING CYCLONE
10	FLARE 10
11	FLARE 11
FUG	Fugitive Emissions

Scale

0 300 600 900 1200 1500

(feet)

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Figure 3-2
CC Plant Plot Plan

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Section 4
Project and Process Description

Equistar plans to expand production at its Olefins Plant in Corpus Christi, Texas. The Olefins Plant consists of Ethylene and Gasoline Hydrotreating Units. This proposed project involves changes to the Ethylene Unit. A process description of the existing Ethylene Unit and a description of the proposed changes to that unit associated with the Olefin Plant Expansion Project is provided below. A process flow diagram for the Ethylene Unit is provided in Figure 4-1 and a process flow diagram of the Gas Separation Train is provided in Figure 4-2. The process description and flow diagrams are for anticipated typical operation, and some variation from this description is expected as part of routine plant operation within a range of possible scenarios.

4.1 Existing Ethylene Unit

The Ethylene Unit consists of fifteen (15) pyrolysis or cracking furnaces (13 USC and 2 VMR). The USC cracking furnaces are capable of processing ethane, propane, butane, or liquid. The VMR furnaces process recycled ethane/propane. Furnace effluents are combined and cooled by contacting with recirculation quench oil and pan oil in the primary fractionator. The fractionation step removes the pan oil, quench oil, and fuel oil components. Fuel oil is removed and delivered to product storage, and quench oil and pan oil are separated, cooled, and recirculated.

The primary fractionator overhead is further cooled with circulating quench water and the vapor is sent to the compression system. The condensed hydrocarbon is separated and used to reflux the primary fractionator. The water condensate is filtered, stripped, pressurized and vaporized for use as dilution steam. The cracked gas is compressed in a steam turbine driven, four-stage, centrifugal compressor. Hydrocarbons condensed in the first three stages are flashed back to successively lower stages. Hydrocarbons from primary fractionation and compression, consisting of C5’s and heavier, join the debutanizer bottoms and flow to the gasoline hydrogenation unit (GHU).

Acid gas is removed between the third and fourth compression stages by the caustic scrubber system. The liquid waste blowdown (spent caustic) from the scrubber is disposed of in permitted deep disposal wells. Cracked gas from the final compression stage flows to the drying system for removal of water and is subsequently conveyed to the demethanizer system, where it is cooled in four stages by heat exchange and by refrigeration to -200°F. Condensate from each separation stage is fed to the demethanizer, where methane plus residual hydrogen is taken overhead.

Hydrogen-rich gas from the final demethanizer feed separator is cooled in a single-stage system utilizing the cooling effect of the liquid condensate for automatic refrigeration to produce a 95 mole percent hydrogen stream. After warming to ambient temperature for recovery of refrigeration, the hydrogen is methanated and dried and then used for hydrogenation of acetylenes contained in the C2 and C3 streams. Hydrogen is also used for treating pyrolysis gasoline. Excess hydrogen is exported, used as fuel gas, or routed to a flare.

Bottoms from the demethanizer are fractionated in a deethanizer, depropanizer, debutanizer sequence. The overhead product from the deethanizer is catalytically hydrogenated in reactors to convert acetylene and then fractionated to ethylene and ethane in the ethylene fractionator. Ethylene is withdrawn from a purification section, pumped, heated, and delivered to the battery limits of the plant. Recycle ethane from the bottom of the fractionator is vaporized and superheated before passing to one of the pyrolysis furnaces. Ethane may also be routed to fuel gas.

Bottoms from the deethanizer are fed to the depropanizer. The propylene-propane net overhead, after catalytic hydrogenation, flows to the secondary deethanizer where the light ends from the hydrogenation are separated from the C3 stream. C3's are further fractionated in the propylene tower producing polymer-grade propylene product. Propane rejected in the propylene tower is recycled to the ethane pyrolysis furnace or routed to fuel gas.

The depropanizer bottoms are fed to the debutanizer, producing a C4 fraction product. Bottoms from the debutanizer combine with distillate from the primary fractionation system and are sent to the GHU. An ethylene/propylene cascade arrangement, which provides ethylene refrigeration at -149°F and -90°F, and propylene refrigeration at -28°F, 0°F and 45°F, furnish the refrigeration for the low-temperature fractionation system. Where possible, refrigerant vapors are condensed in reboilers or cooled by process streams for increased refrigeration economy. Refrigeration compressors are driven by steam turbines.

4.2 Proposed Changes

The following changes to the existing Ethylene Unit are proposed to enable an increased production capacity:

- Increase maximum firing rates of four (4) cracking U.S.C. furnaces from 153 MMBtu/hr to 188 MMBtu/hr each (HHV) (EPNs 1A, 1B, 1K, and 1L);
- Increase VMR furnace A & B maximum firing rates from 93 MMBtu/hr to 126.7 MMBtu/hr each (HHV) (EPNs 3A and 3B);
- Revise the tubing configurations of seven (7) cracking U.S.C. furnaces and increase maximum firing rates from 153 MMBtu/hr to 290 MMBtu/hr each (HHV) (EPNs 1C, 1D, 1E, 1F, 1G, 1H, 1J);
- Increase maximum firing rates of two U.S.C. furnaces from 260 MMBtu/hr to 290 MMBtu/hr each (HHV) (EPNs 1M and 1N);
- Increase maximum firing rates for two (2) steam super heaters from 67 MMBtu/hr to 146 MMBtu/hr each (HHV)(EPNs 5A and 5B);
- Enable the use of higher hydrogen fuel gas for combustion heat, but retain the ability to use low hydrogen fuel gas, by installing new ultra-low NOx burners in all fifteen (15) cracking furnaces (EPNs 3A, 3B, 1A through 1H and 1J through 1N) and the two (2) steam super heaters (EPNs 5A and 5B);
- Install a new Demethanizer Tower, Residue Gas Rectifier, and Acetylene Converter to enable the processing of the increased quantity of cracked gas;
- Addition of associated process drums;
- Addition of fugitive components (necessary valves, connectors, pumps, compressors, etc.); and
- Addition of cooling tower cells.

ETHYLENE UNIT

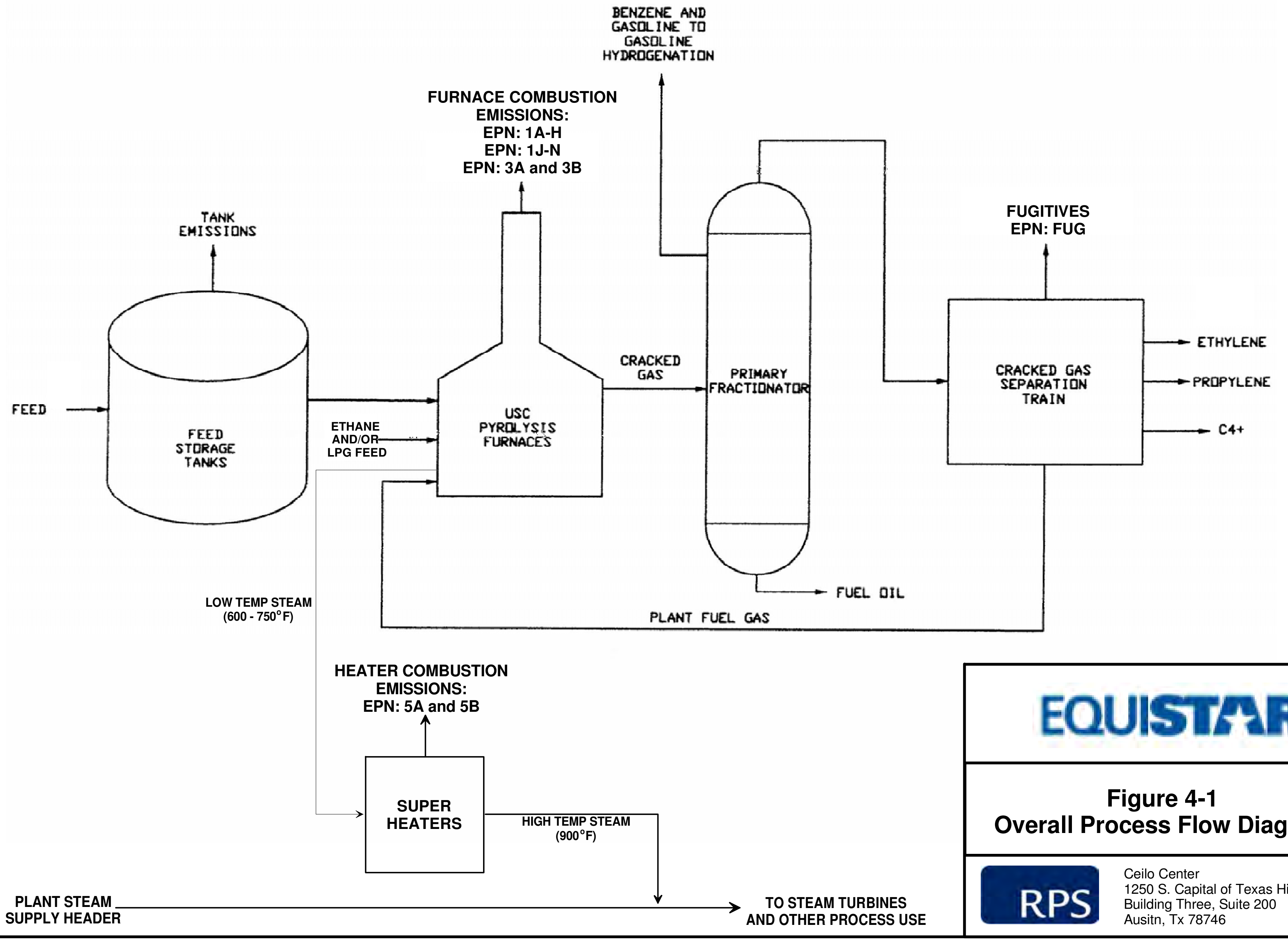

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Figure 4-1
Overall Process Flow Diagram

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CRACKED GAS SEPARATION TRAIN

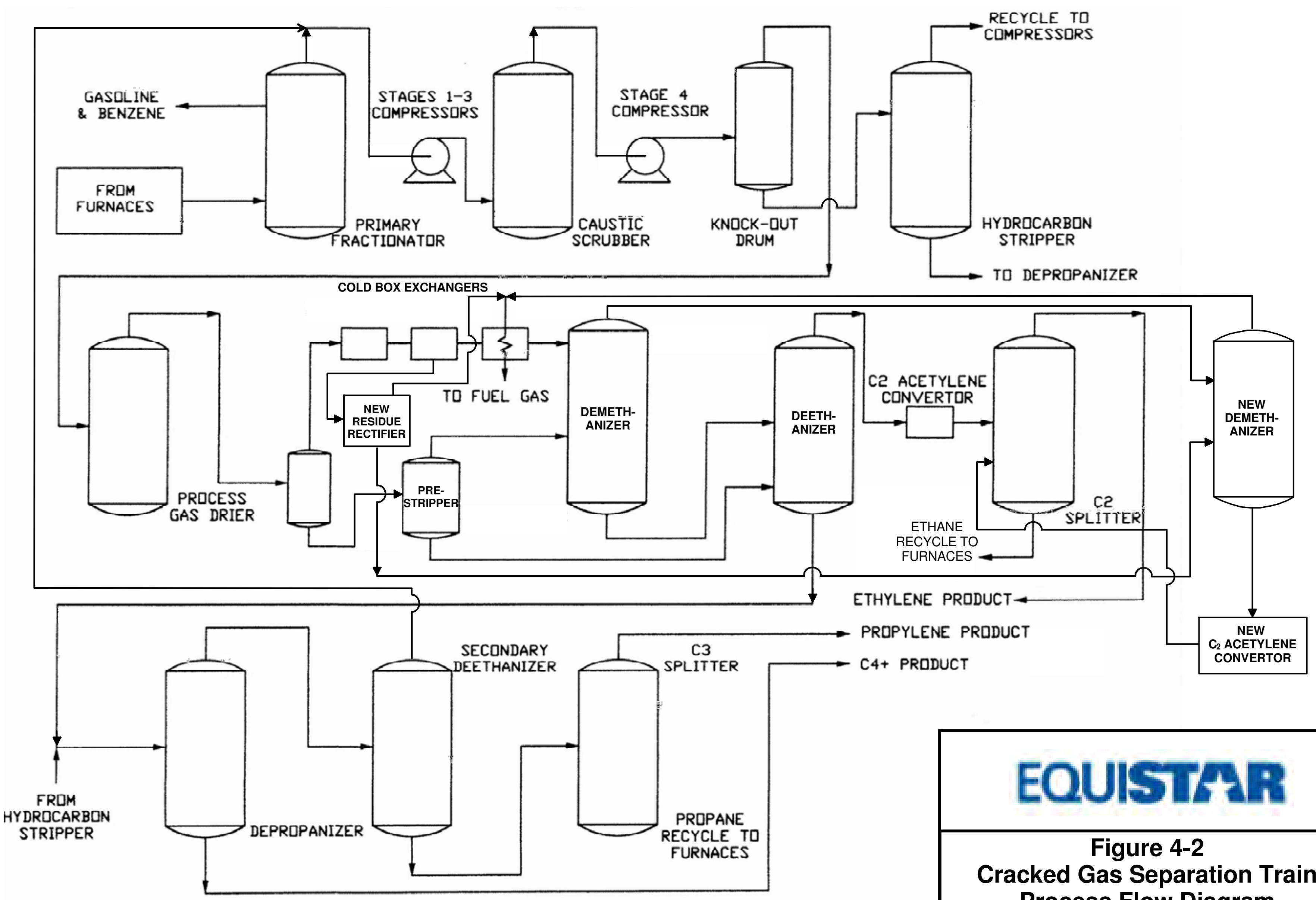

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Figure 4-2
Cracked Gas Separation Train
Process Flow Diagram

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Section 5
Emission Rate Basis

This section contains a description of the increases in GHG emissions from project emission sources. GHG emission calculations methods are also described, and the resulting GHG emission rates are presented in Table 5-1 for each emission point. Emissions calculations are included in Appendix A for reference purposes. In the proposed project, specific GHGs will be emitted from the following sources, and no other GHGs (i.e., SF6, hydrofluorocarbons, and perfluorocarbons) will be emitted from the project beyond those indicated below:

- Cracking Furnaces (CO_2, N_2O and CH_4)
- Steam Super Heaters (CO_2, N_2O and CH_4)
- Flares (CO_2, N_2O and CH_4)
- Decoke Vents (CO_2)
- Fugitive Emissions (CH_4)

5.1 Furnace Fuel Combustion Emissions

Maximum annual GHG fuel combustion emission calculations for the fifteen (15) Olefins Plant furnaces are based on the continuous firing (8,760 hr/yr) of each furnace at the maximum fuel firing rate. Carbon dioxide emissions are calculated in Appendix A based on the carbon content of the fuel using Equation C-5 in 40 CFR Part 98, Chapter C. Emissions of CH_4 and N_2O are calculated from the emission factors on Table C-2 of Appendix A to 40 CFR Part 98, Chapter C. Maximum furnace CO_2 equivalent emissions are calculated by multiplying calculated annual CO_2, CH_4 and N_2O emissions in tons/yr by their respective global warming potentials listed on Table A-1 in 40 CFR Part 98, Chapter A. Project furnace annual CO_2 equivalent emission increases are calculated by subtracting past two year annual average CO_2 equivalent emissions from the previously calculated maximum furnace CO_2 equivalent emissions.

5.2 Furnace Decoking Emissions

In addition to typical fuel combustion emissions, the furnaces will also have decoking GHG emissions. Carbon dioxide decoking emissions are calculated from design specific CO emission factors for VMR, USC-188 MMBtu/hr and USC-290 MMBtu/hr furnaces, and process knowledge that decoking combustion products contain 3 moles of CO_2 for each mole of CO. Furnace CO factors of 1,330.73 lb CO/decoke, 870.26 lb CO/decoke and 2,809.46 lb CO/decoke are multiplied by conversion factors (1 lb-mole CO/ 28 lb CO, 3 lb-moles CO_2/ lb-mole CO and 44 lb CO_2 / lb-mole CO_2) to derive VMR, USC-188 MMBtu/hr and USC-290 MMBtu/hr furnace CO_2 emission factors of 6,272.60 lb CO_2/decoke, 4,102.65 lb CO_2/decoke and 13,244.60 lb CO_2/decoke, respectively. Maximum decoking CO_2 emissions for each furnace in tons/yr are derived by multiplying the previously calculated CO_2 emission factor (in lb CO_2/decoke) by the maximum annual number of decoking events for its furnace design and by a 1 ton/ 2,000 lb conversion factor. The furnace CO_2 emissions are summed to get a combined maximum annual tpy value.

5.3 Steam Super Heater Emissions

Maximum annual GHG fuel combustion emission calculations for Steam Super Heater EPNs 5A and 5B are based on the continuous firing (8,760 hr/yr) at the new maximum heat input of 145.6 MMBtu/hr for each Heater. Carbon dioxide emissions are calculated in Appendix A based on the carbon content of the fuel using Equation C-5 in 40 CFR Part 98, Chapter C. Emissions of CH_4 and N_2O are calculated from the emission factors on Table C-2 of Appendix A to 40 CFR Part 98, Chapter C. Maximum Heater CO_2 equivalent emissions are calculated by multiplying calculated annual CO_2, CH_4 and N_2O in tons/yr by their respective global warming potentials listed in 40 CFR Part 98. Project Heater annual CO_2 equivalent emission increases are calculated by subtracting past two year annual average CO_2 equivalent emissions from the previously calculated maximum Steam Super Heater CO_2 equivalent emissions.

5.4 Flare Emissions

Equistar’s planned Olefins Plant Expansion project will result in the increased maintenance, start-up and shutdown (MSS) waste gas stream flaring activities. These waste gas streams contain VOCs that when combusted by the flare produce CO_2 emissions. The sweep gas, used to help maintain a minimum flare stream heating value for complete combustion and ensure safe operation of the flare header, will also contain hydrocarbons that produce CO_2 emissions when burned. Any unburned methane from the flare will also be emitted to the atmosphere, and small quantities of N_2O emissions can result from the combustion process. Emissions of these pollutants were calculated based on the carbon content of the waste streams sent to the flare and of the sweep gas with the same equations and emission factors from 40 CFR Part 98 that were used for the furnace and heater combustion emissions. These equations and factors were applied to the maximum projected annual waste gas and sweep gas flow rates to derive maximum annual flare emissions.

5.5 Process Fugitive Emissions

Process fugitive (equipment leak) GHG pollutant releases consist of methane (and 0.01 tpy of CO_2) emissions from the new project piping components (EPN FUG). All emissions calculations utilize current TCEQ factors and methods in the TCEQ's *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.* Each fugitive component was classified first by equipment type (valve, pump, relief valve, etc.) and then by material type (gas/vapor, light liquid, heavy liquid). Uncontrolled emission rates were obtained by multiplying the number of fugitive components of a particular equipment/material type by the appropriate Synthetic Organic Chemicals Manufacturing Industry (SOCMI) emission factor. The uncontrolled fugitive stream emission rates were multiplied by the appropriate TCEQ 28VHP Program control factor, which is the LDAR program determined to be BACT in Section 6.5, to derive a controlled stream emission rate. Individual speciated GHG emissions were derived by multiplying the controlled stream emission rate by the weight percent of GHG pollutant in the process stream. Each speciated GHG emission rate was multiplied by its Global Warming Potential (located in 40 CFR 98, Subpart A, Table A-1) to calculate an annual GHG pollutant emission rate in tpy of CO_2e emissions. The fugitive emissions calculations are included in Appendix A for reference purposes.

Table 5-1 Proposed GHG Emission Limits

Description	EPN	CO_2e Emission Rate (tpy)
U.S.C. FURNACE “A”	1A	94,290
U.S.C. FURNACE “B”	1B	94,290
U.S.C. FURNACE “C”	1C	145,448
U.S.C. FURNACE “D”	1D	145,448
U.S.C. FURNACE “E”	1E	145,448
U.S.C. FURNACE “F”	1F	145,448
U.S.C. FURNACE “G”	1G	145,448
U.S.C. FURNACE “H”	1H	145,448
U.S.C. FURNACE “J”	1J	145,448
U.S.C. FURNACE “K”	1K	94,290
U.S.C. FURNACE “L”	1L	94,290
U.S.C. FURNACE “M”	1M	145,448
U.S.C. FURNACE “N”	1N	145,448
V.M.R. FURNACE “A”	3A	63,546
V.M.R. FURNACE “B”	3B	63,546
STEAM S. HEATER “A”	5A	73,025
STEAM S. HEATER “B”	5B	73,025
SOUTH DECOKING CYCLONE	9A	724
NORTH DECOKING CYCLONE	9B	545
Fugitive Emissions	FUG	190
Flare MSS Emissions	MSS	1,678
Total		**1,962,473**

Note: Underlying data in this table may not be accurate to the apparent number of significant digits.

Section 6
Best Available Control Technology

New or modified facilities must utilize best available control technology (BACT) as specified in federal PSD permitting guidance, with consideration given to the technical practicability and economic reasonableness of reducing or eliminating the emissions from the facility. Each facility is evaluated on a case-by-case basis.

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:1A, 1B, 1C, 1D, 1E, 1F, 1G, 1H, 1J, 1K, 1L, 1M, 1N, 3A & 3B)
- Steam Super Heaters (EPN: 5A & 5B)
- Decoking Drum (EPN: 9A & 9B)
- Flares (EPNs:10 & 11)
- Fugitive Emissions (EPN: FUG)

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.

The only PSD pollutant addressed in this permit application is GHG. The list of new, modified or affected project equipment associated with the project that emit GHGs consists of fifteen (15) pyrolysis (cracking) furnaces, two Steam Super Heaters, an existing flare and new process fugitive components. BACT applies to each of the new or modified sources of GHG emissions. Section 6 contains the required BACT evaluation for each of the applicable new or modified emission sources.

The U.S. EPA-preferred methodology for a BACT analysis for pollutants and facilities subject to PSD review is described in a 1987 EPA memo (U.S. EPA, Office of Air and Radiation Memorandum from J.C. Potter to the Regional Administrators, December 1, 1987). This methodology is to determine, for the emission source in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. In addition, a control technology must be analyzed only if the applicant opposes that level of control.

In an October 1990 draft guidance document (*New Source Review Workshop Manual (Draft*), October 1990), EPA set out a 5-step process for conducting a top-down BACT review, as follows:

1) Identification of available control technologies;
2) Technically infeasible alternatives are eliminated from consideration;
3) Remaining control technologies are ranked by control effectiveness;
4) Evaluation of control technologies for cost-effectiveness, energy impacts, and environmental effects in order of most effective control option to least effective; and
5) Selection of BACT.

In its *PSD and Title V Permitting Guidance for Greenhouse Gases* (November 2010), EPA reiterates that this is also the recommended process for permitting of GHG emissions under the PSD program. As such, this BACT analysis follows the top-down approach.

The first step is to identify potentially available control options for each GHG emission source subject to BACT review. Available controls are the technologies with a potentially practical application to the emission source under evaluation. In conducting BACT analyses, the following sources are typically consulted when identifying potential control technologies:

- USEPA RACT/BACT/LAER Clearinghouse (RBLC);
- USEPA New Source Review Website and Regulations;
- State agency website, regulations, guidance and files;
- Similar control application engineering experience; and
- GHG Guidance Documents and Reports including:
  - "Available and Emerging Technologies For Reducing GHG Emissions From Industrial, Commercial, and Institutional Boilers" published by USEPA Office of Air and Radiation;
  - "PSD and Title V Permitting Guidance for Greenhouse Gases" published by USEPA Office of Air and Radiation;

- "Report of the Interagency Task Force on Carbon Capture and Storage" obtained from http://www.epa.gov/climatechange/policy_task_force.html; and
- "Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry" by Maarten Neelis, Ernst Worrell and Eric Masanet.

The second step is to eliminate technically infeasible control options from the BACT evaluation. A technology must be both available and technically proven to be considered feasible. To be considered available, a control technology must have reached the licensing and commercial sales phase of development so it is "commercially available".

6.1 Furnace Combustion

The furnace modifications that are described in this permit application and will occur on existing furnaces and not new sources.

6.1.1 Step 1 – Identification of Potential Control Technologies

To maximize Olefins Plant thermal efficiency, the modified cracking furnaces are designed to achieve high thermal efficiencies that minimize GHG emissions. Planned furnace modifications like the installation of new burners are being designed to achieve a high thermal efficiency. Potentially applicable technologies to minimize GHG emissions from the cracking furnaces include the following:

- Periodic Tune-up – Periodically tune-up of the furnaces to maintain optimal thermal efficiency.
- Furnace Design – Good furnace burner and combustion design to maximize thermal efficiency,
- Furnace Air/Fuel Control – Monitoring of flue gas oxygen concentration, which will be employed along with dry low-NOx burner installations to control air to fuel ratio on a continuous basis for optimal efficiency.
- Waste Heat Recovery – Use of heat recovery from both the furnace exhausts and process streams to preheat the furnace combustion air, ethylene unit feedstock, or to produce steam for use at the site.
- Use of Low Carbon Fuels – Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. Selecting low carbon fuels is a viable method of reducing GHG emissions.
- CO_2 Capture and Storage – Capture and compression, transport, and geologic storage of the CO_2.

A RACT/BACT/LAER Clearinghouse (RBLC) search was also conducted in an attempt to identify BACT options that have been implemented or proposed for other similar gas fired combustion facilities. The results of this search are presented in Appendix B. No additional technologies were identified as a result of the RBLC review. The control methods identified in the search were limited to the first three options listed above (tune-ups, good design, and good combustion control and operation). Information from *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008) was also used in the preparation of this analysis.

6.1.2 Step 2 – Elimination of Technically Infeasible Alternatives

Step 2 eliminates any identified control technology that is not considered technically feasible.

6.1.2.1 Tune-up

Periodic tune-ups represent a technically feasible control technology for the furnaces.

6.1.2.2 Furnace Design

Good Furnace Design represents a technically feasible control technology for the furnaces.

6.1.2.3 Furnace Air/Fuel Control

Air/Fuel Ratio Control represents a technically feasible control technology for the furnaces.

6.1.2.4 Low Carbon Fuels

Low Carbon Fuels represent a technically feasible control technology for the furnaces.

6.1.2.5 Waste Heat Recovery/Air Preheater

The furnaces currently utilize waste heat recovery in generating steam, which results in a low exhaust gas temperature (below 400^{o}F) that does not contain sufficient residual thermal energy to allow the effective recovery of additional heat through retrofit technology. For example, use of flue gas heat recovery to preheat the furnace combustion air is typically only considered practical if the exhaust gas temperature is higher than 650^{o}F (*Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008)). Consequently, additional waste heat recovery is not a viable control option for the proposed Olefins Plant furnace modifications and will not receive further consideration in this BACT evaluation.

6.1.2.6 Carbon Capture and Sequestration

Carbon capture and sequestration (CCS) is not considered to be a viable alternative for controlling GHG emissions from gas-fired facilities due to the low partial pressure of the CO_2 in the flue gas. However, for completeness, this control option is included in the remainder of this BACT analysis, and the reasons that it is not considered viable are discussed in Section 6.1.4.

In summary, all other options identified in Step 1 are considered to be technically feasible, except the CCS option. CCS is technically infeasible, but will continue to be evaluated with the technically feasible options in Step 3 for completeness purposes.

6.1.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Step 3 consists of ranking technically feasible GHG emission controls from the most stringent to the least stringent. The remaining technologies applicable to the proposed furnace design in order of most effective to least effective include:

- CO_2 capture and storage (up to approximately 90% on an annual average basis)[1],
- Use of low carbon fuels (varies according to carbon content),[2]
- Furnace Design (up to 10%),[3,4]
- Air/Fuel Control (5 - 25%),[3,4]
- Periodic tune-up (up to 10% for boilers; information not found for furnaces),[3] and
- Product Heat Recovery (does not directly improve furnace efficiency)[2].

Each technically feasible control technology listed is discussed in the following subsections.

6.1.3.1 Carbon Capture and Sequestration (CCS)

Carbon Capture and Sequestration represents an emerging technology that has only been demonstrated on a very limited number of previous applications such as large power plant combustion units. According to technical literature[1], CCS is capable of achieving an annual average 90% reduction in emissions from large combustion units with a concentrated CO_2

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[1] Controlling Power Plant CO2 Emissions: A Long Range View, Marion, Nsakala, Griffin and Bill, Page 5.
[2] Similar control application engineering experience
[3] Available and Emerging Technologies For Reducing GHG Emissions From Industrial, Commercial, and Institutional Boilers, Page 8 through 15.
[4] Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry.
[5] RBLC BACT data retrieval shown in Appendix B.
[6] PSD and Title V Permitting Guidance for Greenhouse Gases, Appendix Page F-1.

exhaust stream. The 90% represents the fraction of CO_2 captured from the flue gas, without regard for the CO_2 created in the otherwise unnecessary power generation needed to operate the energy intense CO_2 recovery system.

A search of both regulatory and industry files did not find evidence that CCS technology has ever been demonstrated on Olefins Plant cracking furnaces. Although CCS is not a technically proven or viable control technology for the Equistar Olefins Plant Expansion Project, it will be further evaluated for completeness purposes as mentioned previously.

6.1.3.2 Low Carbon Fuels

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel to CO_2. Some processes produce significant quantities of concentrated hydrogen, which produces no CO_2 emissions when burned. Thus, use of a completely carbon-free fuel such as 100% hydrogen, has the potential of reducing CO_2 emissions by 100% and is being included in this low carbon fuel evaluation. Hydrogen is typically only a viable low carbon fuel at industrial plants that generate purified hydrogen internally. The Equistar Olefins Unit like most other industrial facilities will not generate a pure hydrogen stream that may be employed as a fuel supply. Although the use of 100% hydrogen is not a viable alternative to supply the proposed Olefins Plant Expansion Project, there are other low carbon fuel alternatives, including fuel gases with significant hydrogen concentrations that may be utilized to reduce GHG emissions.

Fuels used in industrial process and power generation typically include coal, fuel oil, natural gas and similar process fuel gases. Equistar's annual average fuel gas composition contains more hydrogen and a lower carbon content to produce CO_2 emissions that are even lower than the 59 kg/MMBtu emission factor in 40 CFR 98, Subpart C, Table C-1 for typical fuel gas. Appendix A CO_2 emission calculations that are based on the worst-case annual average carbon content of the fuel and 40 CFR 98, Subpart C, Equation C-5 result in an annual average gaseous fuel CO_2 emission factor equivalent to 51.69 kg/MMBtu for the furnaces, versus a 97.02 kg/MMBtu value for sub bituminous coal on Table C-2 in 40 CFR Part 98, Subpart C. None of the liquid and solid fuels identified in Table C-2 has a lower CO_2 factor than Equistar's worst-case furnace fuel CO_2 emission factor. Only coke oven gas in 40 CFR Part 98, Subpart C, Table C-2 has a lower CO_2 emission factor than the Olefins Plant fuel, but it is not a viable fuel for the proposed furnaces since the Olefins Plant will not contain coke ovens. Therefore, gaseous furnace fuels that include fuel gas, natural gas, or a combination represent the lowest carbon dioxide emitting fuel available for use in the Olefins Plant Expansion Project furnaces.

6.1.3.3 Furnace Design

Good furnace design is considered effective and has a range of efficiency improvements that cannot be directly quantified; therefore, the above ranking is approximate only. The estimated efficiencies for each of these control technologies listed were obtained from *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008). This report addressed improvements to existing energy systems, as well as new equipment; thus, the higher end of the range of stated efficiency improvements that can be realized is assumed to apply to the existing (older) facilities, with the lower end of the range being more applicable to new furnace designs.

6.1.3.4 Air/Fuel Control

GHG emissions may be minimized through the use of air to fuel ratio controls that limit the amount of excess oxygen to slightly above stoichiometric levels. An air to fuel control system has been successfully employed on ethylene furnaces and wide of other industrial combustion equipment applications. The estimated efficiency for this control technology was obtained from *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008) and included in the BACT determination.

6.1.3.5 Periodic Tune-up

Furnace GHG emissions may be reduced by up to 10% through the use of periodic tune-ups to establish a combustion process that proceeds as efficiently as possible. This helps to ensure that maximum thermal efficiency is maintained. Periodic furnace tune-ups include the following activities:

- Air to fuel control system and associated fuel gas flow meter preventive maintenance;
- Furnace burner adjustment, cleaning, replacement and preventive maintenance; and
- Oxygen control analyzer checks and preventive maintenance.

The estimated efficiency for this control technology was obtained from *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008).

6.1.3.6 Waste Heat Recovery/Air Preheater

The furnaces currently utilize waste heat recovery to generate steam and will continue to employ this GHG emission control technology after implementation of the Olefins Plant Expansion Project.

6.1.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Step 4 requires that each remaining control technology be further evaluated to assess the potential for adverse environmental, economic and energy impacts. This evaluations are presented in the following sub-sections in accordance with the effectiveness of each control option established in Section 6.1.2 starting with the most stringent control system.

6.1.4.1 Carbon Capture and Sequestration

As stated in Section 6.1.2, carbon capture and sequestration (CCS) is not considered to be a viable alternative for controlling GHG emissions from fuel gas or natural gas fired facilities. A technology must be both available and technically proven to be considered feasible. In this context, CCS is not considered to be an available control technology for use on the cracking furnaces.

This conclusion is supported by the BACT example for a natural gas fired boiler in Appendix F of EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (November 2010). In the EPA example, CCS is not even identified as an available control option for natural gas fired facilities. Also, on pages 33 and 44 of the Guidance Document, it states:

> "For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is available for large CO2-emitting facilities including fossil fuel-fired power plants and 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). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs."

The CO_2 streams included in this permit application are similar in nature to the gas-fired industrial boiler in the EPA Guidance Appendix F example and are dilute streams, and thus are not among the facility types for which the EPA guidance states CCS should be listed in Step 1. Although the proposed facility is not one of the listed facility types for which CCS should be considered, it was further evaluated for the project to ensure that the analysis was complete.

Equistar has performed an order of magnitude cost analysis for CCS applied to the Furnaces addressed in this permit application for completeness purposes. The results of the analysis, presented in Table 6-1, show that the cost of CCS for the project would be approximately $96 per ton of CO_2 emissions controlled, which is not considered to be cost effective for GHG control. This equates to a total annual CCS cost of more than $188,151,000 per year for the Olefins Plant Expansion Project. The best estimate of the total capital cost of the Olefins Plant Expansion Project is a nominal $417,000,000. Based on a 7% interest rate, and 20 year equipment life, this cost equates to an annualized cost of $39,361,850. Thus, the additional annualized cost for CCS controls would be over 478% of the entire project's base cost, which obviously exceeds the threshold that would make CCS economically viable for the project.

There are additional negative impacts associated with use of CCS for the proposed Furnaces. The additional process equipment required to separate, cool, and compress the CO_2 would require a significant additional power and energy expenditure. This equipment would include amine units, dehydration units, and compression facilities. The power and energy must be provided from additional combustion units, including furnaces, engines, and/or combustion turbines. 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-terms concerns for CCS:

- 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.

Based on both the excessive cost effectiveness in $/ton of GHG emissions controlled and the inability of the project to bear the high cost and the associated negative environmental and energy impacts, CCS is rejected as a control option for the proposed project

6.1.4.2 Use of Low Carbon Gas Fuel

Gaseous fuels contain the lowest carbon content and emit the lowest amount of CO_2 emissions for the available furnace fuels. According to 40 CFR 98, Subpart C, Table C-1, gaseous fuels (like the proposed fuel gas, natural gas, or a combination) have a significantly lower CO_2 emission rate than liquid or solid fuels.

The fuel for the cracking furnaces consists primarily of fuel gas produced as a byproduct of the Ethylene Unit. The fuel gas is considered a readily available and cost effective fuel alternative. The fuel gas typically has a significant hydrogen content, particularly when using ethane as a feedstock, which minimizes the carbon content of the fuel gas and the resulting CO_2 emissions. Fuel gas can be supplemented with natural gas as required based on fuel gas availability. These gaseous fuels are also a very clean burning fuel with respect to criteria pollutants and thus have minimal environmental impact compared to liquid and solid fuels. This makes such gaseous fuels the commonly selected fuel of choice for most industrial facilities, especially Olefins Plants, in addition to being the lowest carbon fuels available. Although use of Equistar’s gaseous fuel (fuel gas from the Olefins Plant, natural gas or a combination) results in annual CO_2 emissions equivalent to 51.69 kg/MMBtu, which is about 30% less CO_2 emissions than diesel fuel and 47% less CO_2 emissions than sub bituminous coal; it is more prudent to consider gaseous fuel to be the “baseline” fuel for this BACT analysis; otherwise, claiming an emission reduction from its use could be deemed a misrepresentation.

6.1.4.3 Furnace Design

Furnaces can be designed and retrofitted with efficient burners, state-of-the-art refractory and insulation materials in the furnace walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency by introducing additional mass of air that is heated and carried out of the furnace, and by reducing the radiant firebox temperature. The function and near steady state furnace operation allows it to be designed to achieve “near best” thermal efficiency.

6.1.4.4 Air/Fuel Controls

Some amount of excess air is required to ensure complete fuel combustion, minimize emissions, and for safety reasons. More excess air than needed to achieve these objectives reduces overall furnace efficiency. Manual or automated air/fuel ratio controls are used to optimizes these parameters and maximize the efficiency of the combustion process. Automated controls are considered more effective than manual controls.

6.1.4.5 Periodic Furnace Tune-ups

Periodic tune-ups of the furnaces include:

- Preventive maintenance check of fuel gas flow meters annually;
- Preventive maintenance check of oxygen control analyzers quarterly;
- Cleaning of burner tips on an as-needed basis; and
- Cleaning of convection section tubes on an as-needed basis.

These activities insure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement, although convection cleaning has shown improvements in the 0.5 to 1.5% range.

6.1.4.6 Waste Heat Recovery/Air Preheater

The furnaces currently utilize waste heat recovery to generate steam and will continue to employ this GHG emission control technology after implementation of the Olefins Plant Expansion Project.

6.1.5 Step 5 – Selection of BACT

The preceding evaluation has determined that the use of efficient furnace design, low carbon fuel, periodic tune-ups, waste heat recovery, product heat recovery and air/fuel controls are BACT for the modified furnace GHG emissions from the planned Olefins Plant Expansion Project. These technologies and additional BACT practices proposed for the furnaces are listed below:

- Use of low carbon fuel (fuel gas and/or natural gas). Fuel gas and/or natural gas will be fired in the modified furnaces. These gaseous fuels represents the lowest carbon fuel available for use at the Olefins Plant.

- Determine CO_2e emissions from the modified Olefins Plant furnaces based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance.

- Good design to maximize heat transfer efficiency in the furnaces and reduce heat loss. Materials such as Ceramic fiber blankets and Kaolite™ of various thickness and density will be used where feasible on furnace surfaces. Kaolite™ is a super light low thermal conductivity insulation material that reduces heat transfer producing significant savings in furnace fuel consumption.

- Demonstrate modified furnace efficiencies by monitoring the exhaust temperature, fuel temperature, ambient temperature, and excess oxygen.
- The modified furnaces will be designed and operated to achieve the maximum possible thermal efficiency for the current equipment configuration.
- Utilize an air/fuel control system to maximize modified furnace combustion efficiency.
- Clean furnace burner tips and convection tubes as needed.
- Calibrate and perform annual preventive maintenance on the furnace fuel flow meter and air/fuel control analyzers.
- Maintain current waste heat recovery equipment, procedures and practices as required.

6.2 Furnace Decoking

Equistar’s planned Olefins Plant Expansion Project will result in the modification of fifteen furnaces that will require periodic decoking to remove coke deposits from the process side (inside) of the tubes. Coke build-up occurs continuously during olefins production and must be eliminated to maintain high heat transfer efficiency. Equistar introduces super heated steam and air to initiate the combustion of coke that builds-up inside the furnace tubes and produce CO_2 emissions, which enter the atmosphere through decoking drums. The following subsections contain a BACT evaluation for these periodic decoking activities.

6.2.1 Step 1 – Identification of Potential Control Technologies

An RBLC search was conducted to identify potentially feasible control technologies for decoking activities. However, no GHG control technologies were identified as a result of the RBLC search. The following are two GHG control technologies known to minimize potential CO_2 emissions generated from decoking activities:

- Limiting air and steam during the decoking process and
- Proper furnace design and operation to minimize coke formation.

6.2.2 Step 2 – Elimination of Technically Infeasible Alternatives

It is possible to minimize both the quantities of air and steam and update the furnace design to minimize the amount of CO_2 generated from decoking activities. Therefore, all options identified in Step 1 are considered technically feasible.

6.2.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Step 3 consists of ranking technically feasible GHG emission controls from the most stringent to the least stringent. The remaining technologies applicable to ethylene furnace decoking activities in order of most effective to least effective include:

- Limiting air and steam flow during the decoking process and
- Proper furnace design and operation to minimize coke formation.

Each technically feasible control technology listed is discussed in the following subsections.

6.2.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Step 4 requires that each remaining control technology be further evaluated to assess the potential for adverse environmental, economic and energy impacts. This evaluations are presented in the following sub-sections in accordance with the effectiveness of each control option established in Section 6.1.2 starting with the most stringent control system.

6.2.4.1 Air and Steam Limit

Limiting air and/or steam flow during the decoking process will reduce CO_2 and increase CO emissions by shifting the coke oxidation reaction towards CO and away from CO_2 generation. These limitations are applied to simultaneously erode coke from the tube interiors to supplement removal through combustion and to simultaneously prevent tube overheating from the combustion. Excessive limitation of steam and air could result in a failure to completely remove the deposited coke, making more frequent decoking necessary. This control alternative could result in both an ineffective decoking process and increased CO emissions, which is a criteria pollutant. Therefore, air and/or steam flow restriction controls will not receive further CO_2 BACT consideration for decoking activities.

6.2.4.2 Minimize Coke Formation

Coke formation is an important consideration in ethylene furnace design and operation. Coke deposits act as an insulator to reduce heat transfer efficiency and increase pressure drop that wastes valuable energy resources. Decoking of the furnace tubes becomes necessary once metallurgical or hydraulic limits are reached. The furnace tube coke deposition rate may be minimized by employing proper design and operating controls. Equistar's proposed furnace modifications will include proper design and operating controls to minimize coke build up and meet BACT for decoking CO2 emissions.

6.2.5 Step 5 – Selection of BACT

The preceding analyses have determined that proper furnace design and operation to minimize coke formation is the only remaining control system under evaluation. Therefore, proper furnace design and operation to minimize coke formation is selected BACT for decoking CO_2 emissions.

6.3 Steam Super Heaters

6.3.1 Step 1 – Identification of Potential Control Technologies

Equistar Olefins Plant utilizes super heated steam (as opposed to saturated steam) to power steam turbine drivers on product compressors. The products must be compressed to pipeline pressure so they may be transported to market. High temperature steam production begins with the recovery of waste heat from Ethylene Unit furnace effluent steams that is used to generate 600^{o}F steam. The 600^{o}F steam is piped to one of the two existing Steam Super Heaters (EPNs 5A and 5B) that combust fuel to produce 900^{o}F steam, which is routed a steam header that supplies the plant's steam turbines. The use of waste heat recovery energy, which may otherwise be lost, make the steam powered compression system and associated Steam Super Heater equipment process very energy efficient.

If the Steam Super Heaters were not employed to power the product compression system, another energy source would be required and would emit additional GHG emissions to accomplish this necessary task.

Equistar's Steam Super Heaters are designed to achieve high thermal efficiencies, which minimize GHG emissions. The potentially applicable technologies to minimize GHG emissions from the Steam Super Heaters include the following:

- Periodic Tune-up[2,3,4] – Periodically tune-up of the Heaters to maintain optimal thermal efficiency.
- Good Steam Super Heater Design[3,4] – Good Heater design to maximize thermal efficiency,
- Steam Super Heater Air/Fuel Control[4] – Monitoring of oxygen concentration in the flue gas to be used to control air to fuel ratio on a continuous basis for optimal efficiency.
- Waste Heat Recovery/Air Preheater[3,4,5] – Use of heat recovery from both the Heater exhausts and process streams to preheat the Heater combustion air, feed (oil) to Heaters, or to produce steam for use at the site.

- Use of Low Carbon Fuels[3,4] – Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. Selecting low carbon fuels is a viable method of reducing GHG emissions.

- CO_2 Capture and Storage[3] – Capture and compression, transport, and geologic storage of the CO_2.

The list of potential control technologies was gleamed from previously listed industry and regulatory sources, including a RACT/BACT/LAER Clearinghouse (RBLC) search that was conducted in an attempt to identify BACT options for other similar gas fired combustion facilities. The results of this RBLC search are presented in Appendix B for documentation purposes. The control methods identified in the search were limited to the first three options listed above (tune-ups, good design, and good combustion control and operation). Guidance information from *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008) was also used to identify other potential Steam Super Heater controls.

6.3.2 Step 2 – Elimination of Technically Infeasible Alternatives

Step 2 eliminates any identified control technology that is not considered technically.

6.3.2.1 Tune-up

Periodic tune-ups represent a technically feasible control technology for the Steam Super Heaters.

6.3.2.2 Steam Super Heater Design

Good Steam Super Heater Design represents a technically feasible control technology.

6.3.2.3 Steam Super Heater Air/Fuel Control

Air/Fuel Ratio Control represents a technically feasible control technology for the Steam Super Heaters.

6.3.2.4 Low Carbon Fuels

Low Carbon Fuels represent a technically feasible control technology for the Steam Super Heaters.

6.3.2.5 Waste Heat Recovery/Air Preheater

The Steam Super Heaters currently utilize waste heat recovery in generating steam, which results in a low exhaust gas temperature (approximately 375^{o}F) that does not contain sufficient residual thermal energy to allow for the effective recovery of additional heat. For example, use of flue gas heat recovery to preheat the Steam Super Heater combustion air is typically only considered practical if the exhaust gas temperature is higher than 650^{o}F (*Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008)). Consequently, additional waste heat recovery is not a viable control option for the proposed Olefins Plant Steam Super Heater modifications and will not receive further consideration in this BACT evaluation.

6.3.2.6 Carbon Capture and Sequestration

As mentioned in Section 6.1., carbon capture and sequestration (CCS) is not considered to be a viable alternative for controlling GHG emissions from gas-fired industrial furnaces and heaters. Therefore, it is not a viable control option and will not receive additional consideration as a control option for GHG emissions from the Steam Super Heaters.

6.3.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Step 3 consists of ranking technically feasible GHG emission controls from the most stringent to the least stringent. The remaining technologies applicable to the proposed Steam Super Heater design in order of most effective to least effective include:

- Use of low carbon fuels (varies according to carbon content)[2];
- Heater Design (up to 10%)[3,4];
- Air/Fuel Control (5 - 25%)[4]; and
- Periodic tune-up (up to 10% for boilers; information not found for heaters)[3,4].

Each technically feasible control technology listed is discussed in the following subsections.

6.3.3.1 Low Carbon Fuels

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel to CO_2. Some processes produce significant quantities of concentrated hydrogen, which produces no CO_2 emissions when burned. Thus, use of a completely carbon-free fuel such as 100% hydrogen, has the potential of reducing CO_2 emissions by 100% and is being included in this low carbon fuel evaluation. Hydrogen is typically only a viable low carbon fuel at industrial plants that generate purified hydrogen internally. The Olefins Plant like most other industrial facilities will not generate a pure hydrogen stream that may be employed as a fuel supply. Although the use of 100% hydrogen is not a viable alternative to supply the proposed Olefins Plant Expansion Project, there are other low carbon fuel alternatives, including fuel gases with significant hydrogen concentrations that may be utilized to reduce GHG emissions.

Fuels used in industrial process and power generation typically include coal, fuel oil, natural gas and similar process fuel gases. Of these, typical fuel gas and natural gas are among the lowest carbon fuel that can be burned, with a CO_2 emission factor of 59 kg/MMBtu and 53.02 kg/MMBtu, respectively. Equistar's annual average fuel composition will contain more hydrogen and a lower carbon content than these typical gaseous fuels and produce CO_2 emissions that are even lower. Appendix A CO_2 emission calculations that are based on the worst-case annual average carbon content of Equistar's proposed gaseous fuel and 40 CFR 98, Subpart C, Equation C-5 result in an annual average gaseous fuel CO_2 emission factor equivalent to 51.69 kg/MMBtu for the furnaces, versus a 97.02 kg/MMBtu value for sub bituminous coal on Table C-2 in 40 CFR Part 98, Subpart C. None of the liquid and solid fuels identified in Table C-2 has a lower CO_2 factor than Equistar's Steam Super Heater fuel CO_2 emission factor. Only coke oven gas in 40 CFR Part 98, Subpart C, Table C-2 has a lower CO_2 emission factor than the proposed Olefins Plant fuel, but it is not a viable fuel for the Steam Super Heaters since the Olefins Plant will not contain coke ovens. Therefore, gaseous Steam Super Heater fuel that includes fuel gas, natural gas, or a combination represent the lowest carbon dioxide emitting fuel available for use in the Olefins Plant Expansion Project Steam Super Heaters.

6.3.3.2 Steam Super Heater Design

Good Steam Super Heater design, air/fuel ratio control, and periodic tune-ups are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. The estimated efficiencies for each of these control technologies listed were obtained from *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008). This report addressed improvements to existing energy systems, as well as new equipment; thus, the higher end of the range of stated efficiency improvements that can be realized is assumed to apply to the existing (older) facilities, with the lower end of the range being more applicable to new heater designs.

6.3.3.3 Air/Fuel Control

GHG emissions may be minimized through the use of air to fuel ratio controls that limit the amount of excess oxygen to slightly above stoichiometric levels. An air to fuel control system has been successfully employed on units similar to the Olefins Plant Steam Super Heaters and a wide of other industrial combustion equipment application. A proper air to fuel ratio control system may reduce GHG emissions by 5% to 25% depending on the combustion process. Therefore, it is included in the enclosed BACT evaluation.

6.3.3.4 Periodic Tune-up

Steam Super Heater GHG emissions may be reduced by up to 10% through the use of periodic tune-ups to establish a combustion process that proceeds as efficiently as possible. This helps to ensure that maximum thermal efficiency is maintained. Periodic heater tune-ups include the following activities:

- Air to fuel control system and associated fuel gas flow meter preventive maintenance;
- Heater burner adjustment, cleaning, replacement and preventive maintenance; and
- Oxygen control analyzer checks and preventive maintenance.

6.3.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Step 4 requires that each remaining control technology be further evaluated to assess the potential for adverse environmental, economic and energy impacts. This evaluations are presented in the following sub-sections in accordance with the effectiveness of each control option established in Section 6.3.2 starting with the most stringent control system.

6.3.4.1 Use of Low Carbon Gas Fuel

Gaseous fuels contain the lowest carbon content and emit the lowest amount of CO_2 emissions for the available Steam Super Heater fuels. According to 40 CFR 98, Subpart C, Table C-1, gaseous fuels (like the proposed fuel gas, natural gas, or a combination) have a lower CO_2 emission rate than liquid or solid fuels.

The fuel gas is considered a readily available and cost effective fuel alternative. This can be supplemented with natural gas as required based on fuel gas availability. These gaseous fuels are also a very clean burning fuel with respect to GHG pollutants and thus have minimal environmental impact compared to liquid and solid fuels. This makes such gaseous fuels the commonly selected fuel of choice for most industrial facilities, since they represent the lowest carbon dioxide emitting fuels available.

6.3.4.2 Steam Super Heater Design

Steam Super Heaters can be designed with efficient burners, more efficient heat transfer efficiency, state-of-the-art refractory and insulation materials in the heater walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency. Good Steam Super Heater design will require less fuel and generate up to 10% less GHG emissions.

6.3.4.3 Air/Fuel Controls

Some amount of excess air is required to ensure complete fuel combustion, minimize emissions, and for safety reasons. More excess air than needed to achieve these objectives reduces overall Heater efficiency. Air/fuel ratio controls are used to optimizes these parameters and maximize the efficiency of the combustion process.

6.3.4.4 Tune-ups

Periodic tune-ups of the Heaters include:

- Preventive maintenance check of fuel gas flow meters annually;
- Preventive maintenance on air to fuel control system;
- Preventive maintenance on burners;
- Preventive maintenance check of oxygen control analyzers annually; and
- Preventive maintenance on burner tips on an as-needed basis.

These activities insure maximum thermal efficiency is maintained.

6.3.5 Step 5 – Selection of BACT

The preceding evaluation has determined that the use of efficient equipment design, low carbon fuel, periodic tune-ups, product heat recovery and air/fuel controls are BACT for Steam Super Heater GHG emissions. These technologies and additional BACT practices proposed for the furnaces are listed below:

- Use of low carbon fuel (fuel gas and/or natural gas). Fuel gas and/or natural gas will be fired in the modified Steam Super Heaters. This gaseous fuel represents the lowest carbon fuel available for use at the Olefins Plant.

- Determine CO_2e emissions from the Steam Super Heaters based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance.

- Good Steam Super Heater design to maximize heat transfer efficiency and reduce heat loss. Materials such as Ceramic fiber blankets and Kaolite™ of various thickness and density will be used where feasible on Steam Super Heater surfaces. Kaolite™ is a super light low thermal conductivity insulation material that reduces heat transfer producing significant savings in Steam Super Heater fuel consumption.

- Demonstrate Steam Super Heater efficiencies by monitoring the exhaust temperature, fuel temperature, ambient temperature, and excess oxygen.

- The Steam Super Heaters will be designed and operated to achieve the maximum possible thermal efficiency.

- Utilize an air/fuel control system to maximize combustion efficiency on the Steam Super Heaters.

- Calibrate and perform annual preventive maintenance on the fuel flow meter and air/fuel control analyzers.

6.4 Flares

Equistar's proposed Olefins Plant Expansion project will require additional Start-up, Shutdown and Maintenance (MSS) activities and generate VOC waste streams that are combusted in Olefins Plant flares. A Flare GHG BACT evaluation is presented on the following pages for the increase in MSS Flare emissions.

6.4.1 Step 1 – Identification of Potential Control Technologies

Both regulatory and industry resources were consulted in an effort to identify the potential control options for the increased Flare GHG emissions. A description of the potential control options identified is as follows:

- Flaring minimization – Develop and implement a Flaring Minimization Plan with the goal of minimizing the duration and quantity of flaring to the extent possible through good engineering design of the process and good operating practice. Employ a video camera to identify and expedite corrective action for flaring events. Inspect safety relief valves to ensure they relieve at the designated pressure and are in good working condition.

- Proper operation of the flares – Install a flow monitor to measure the amount of waste gas flow and minimize the amount of sweep gas and/or assist gas employed. A certain amount of sweep gas is required for safe operation of the flare gas header; however, the additional amount of sweep gas or assist gas that may be needed to maintain adequate VOC destruction can be minimized in order to minimize CO_2 combustion emissions.

6.4.2 Step 2 – Elimination of Technically Infeasible Alternatives

The primary reason a flare is utilized to control MSS releases is that a flare has the capability to handle the widely variable flows that occur from these activities. This makes a flare the ideal control technology for MSS generated VOC waste streams, especially one that has already been installed. Other combustion controls, such as thermal oxidizers, are effective in controlling less variable process streams; however, they are not designed to handle the highly variable MSS releases that occur from the Olefins Plant.

6.4.2.1 Flaring Minimization

Equistar has developed and implemented a Flaring Minimization Plan with the goal of limiting the quantity of MSS waste stream flow that the flares are required to combust. Company staff will maintain efficient plant operations to minimize MSS waste stream flows to the extent practicable. A video camera is installed to monitor flaring events, so that plant staff may take appropriate action to minimize the duration and quantity of flaring to the extent practicable. Equistar will periodically inspect safety relief valves to ensure they relieve at the designated pressure and are in good working condition. Since Flaring Minimization Plan activities have effectively reduce Olefins Plant Expansion Project GHG emissions, flaring minimization has been determined to be a viable control option for this proposed project.

6.4.2.2 Proper Flare Operation

A certain amount of sweep gas is required for safe operation of the flare gas headers; however, the additional amount of sweep gas and/or assist gas that may be needed to maintain adequate VOC destruction can be minimized in order to minimize CO_2 combustion emissions. Proper flare operation will help ensure that only the necessary amount of supplemental sweep gas will be combusted and associated GHG emissions generated. In addition to closely monitoring flare operating conditions to promote efficient flare combustion, Equistar's staff will utilize a flow monitor to measure the amount of waste gas flow so only the required the amount of sweep and/or assist gas will be employed. This will reduce GHG emissions and make proper flare operation a viable control option.

As a result, flaring minimization and proper operation of the flare are both technically feasible control options and will remain in this BACT evaluation as viable control options for Equistar's Olefins Plant Expansion Project GHG emissions.

6.4.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Flare minimization and proper operation of the flares are potentially equally effective, but have case-by-case effectiveness that cannot be generally quantified to allow ranking.

6.4.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

6.4.4.1 Flaring Minimization

Flaring minimization to reduce the potential quantities of MSS waste gas flows to the flare has no negative economic, energy or environmental impacts.

6.4.4.2 Proper Flare Operation

Proper flare operation and flow analyzer(s) may be employed to minimize the amount of sweep or assist gas that is needed to maintain a minimum heating value of 300 Btu/scf for proper VOC destruction. The added advantage of reducing fuel costs makes this control option cost effective as both a criteria pollutant and GHG emission control option. There is no negative environmental, energy or economic impacts associated with this option.

6.4.5 Step 5 – Selection of BACT

Equistar proposes use of both the Flaring Minimization Plan and proper flare operation controls to minimize Equistar's Olefins Plant Expansion Project GHG emissions. Flare system analyzer(s) will be used to continuously monitor the combined waste gas stream sent to the flares from the proposed facilities. As a result the amount of sweep gas and/or assist gas can be limited to the minimum needed for safe operation of the flare headers and/or to maintain a heating value of 300 Btu/scf for the gases burned in the flares. The efficient use of sweep gas will avoid the production of both unnecessary GHG and criteria pollutant emissions. The proposed Olefins Plant Expansion Project will be designed and operated to minimize the volume of maintenance, start-up and shutdown waste stream material that is the source of waste gas sent to the flares. This evaluation concludes from the preceding analyses that flaring minimization and proper flare operation controls are BACT for GHG flare emissions from the proposed Olefins Plant Expansion Project.

6.5 Process Fugitives (EPN FUG)

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. The additional GHG emissions from process fugitives have been conservatively estimated to be approximately 9.03 tpy methane and 0.01 tpy carbon dioxide emissions (that total to less than 190 tpy of CO_2e). This is a negligible contribution to the 1,050,952 tpy mass (or 1,059,332 tpy CO_2e) GHG emissions increase; however, for completeness, fugitive emissions are addressed in this BACT analysis.

6.5.1 Step 1 – Identification of Potential Control Technologies

The only identified control technology for process fugitive GHG CO_2e emissions is use of a leak detection and repair (LDAR) program. LDAR programs vary in stringency as needed for control of VOC emissions; however, due to the negligible amount of GHG emissions from fugitives, LDAR programs would not be considered for control of GHG emissions alone. As such, evaluating the relative effectiveness of different LDAR programs is not warranted.

6.5.2 Step 2 – Elimination of Technically Infeasible Alternatives

LDAR programs are a technically feasible option for controlling process fugitive GHG emissions.

6.5.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

As stated in Step 1, this evaluation does not compare the effectiveness of different levels of LDAR programs.

6.5.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Although technically feasible, use of an LDAR program to control the negligible amount of GHG emissions that occur as process fugitives for projects like Equistar's Olefins Plant Expansion Project is clearly cost prohibitive. However, if an LDAR program is being implemented for VOC control purposes, it will also result in effective control of the small amount of GHG emissions from the same piping components. Equistar's TCEQ application has determined that TCEQ's 28VHP program is BACT for the Olefins Plant Expansion Project fugitive VOC emissions, which will mandate the implementation of these LDAR controls. Consequently, this makes the 28VHP LDAR program a viable fugitive GHG emission control option for the Olefins Plant Expansion Project, so the 28VHP LDAR program will continue to receive BACT consideration.

6.5.5 Step 5 – Selection of BACT

LDAR monitoring controls represent the only remaining BACT option for Olefins Plant Expansion Project fugitive GHG emissions. Equistar plans to implement TCEQ's 28VHP LDAR program for VOC BACT purposes, which will also effectively minimize GHG emissions to less than 190 tpy of CO_2e. Therefore, this evaluation concludes the proposed 28VHP LDAR program controls will concurrently satisfy VOC and GHG emission BACT requirements.

Table 6-1. Approximate Cost for Construction and Operation of a Post-Combustion Carbon Capture and Sequestration (CCS) System for GHG Emissions Control for the Equistar Olefins Plant Expansion

CCS System Components	Cost (\$/ton of CO_2 Controlled)[1]	Ton of CO_2 per Year[2]	Total Annual Cost
CO_2 Capture and Compression Facilities	\$93.44	1,962,473	\$183,373,758
CO_2 Transport Facilities (per 100km of pipeline)[3]	\$1.81	1,962,473	\$3,560,655
CO_2 Storage Facilities	\$0.62	1,962,473	\$1,216,733
Total CCS System Cost	\$95.87	NA	\$188,151,146

Proposed Plant Cost	Total Capital Cost	Capital Recovery Factor[4]	Annualized Capital Cost
Cost of Liquid Natural Gas Plant without CCS[5]	\$417,000,000	0.0944	\$39,361,850

1. Costs are from Report of the Interagency Task Force on Carbon Capture (August, 2010) . A range of costs was provided for transport and storage facilities; for conservatism, the low ends of these ranges were used in this analysis as they contribute little to the total cost. Reported costs in \$/tonne were converted to \$/ton.
2. Tons of CO2 controlled assumes 90% capture of CO2 emissions from all project sources except for flares and fugitives.

3. Pipeline costs are per 100 km of pipeline. It is assumed that a suitable storage location can be found within 100 km.
4. Capital recovery factor based on 7% interest rate and 20 year equipment life.
5. Estimated Olefins Plant Expansion Total Capital Cost
6. Underlying data in this table may not be accurate to the apparent number of significant digits.

Section 7
Federal New Source Review

Federal NSR applicability for GHG PSD requirements is presented in this section.

7.1 Existing Site Major Source Determination

An existing site is considered a major source of GHG emissions if it has the potential-to-emit greater than 100,000 tpy of GHG emissions. Since the Olefins Plant site where the proposed project will be located currently has a potential-to-emit greater than 100,000 tpy of GHG emissions, it is considered a major source for PSD applicability purposes.

7.2 Federal NSR Applicability

Section 7.2 evaluates the applicability of federal PSD requirements for GHG emissions to Equistar's proposed Olefins Plant Expansion Project. EPA has established the PSD major modification GHG emission threshold for major stationary sources at 75,000 tpy of total carbon dioxide equivalent emissions. Total Olefins Plant Expansion Project GHG emission increases are over the 75,000 tpy major modification threshold as shown in Appendix A, Table A-1. Therefore, the Olefins Plant Expansion Project GHG emissions are subject to federal PSD Program requirements. Equistar is submitting the enclosed application for a PSD permit to authorize the proposed Olefins Plant Expansion Project GHG emissions as required.

Appendix A

Emissions Calculations

Table A-1
GHG INCREASE SUMMARY
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

Source	Description	CO2 Emissions	N2O Emissions	CH4 Emissions
		tpy	tpy	tpy
1A	U.S.C. FURNACE “A”	38,516.46	0.94862	4.04017
1B	U.S.C. FURNACE “B”	40,289.96	0.95315	4.08539
1C	U.S.C. FURNACE “C”	89,826.27	1.54058	7.00491
1D	U.S.C. FURNACE “D”	91,110.74	1.54356	7.03479
1E	U.S.C. FURNACE “E”	87,734.42	1.53517	6.95084
1F	U.S.C. FURNACE “F”	84,259.87	1.52645	6.86370
1G	U.S.C. FURNACE “G”	86,409.83	1.53188	6.91796
1H	U.S.C. FURNACE “H”	90,216.04	1.54157	7.01481
1J	U.S.C. FURNACE “J”	88,865.07	1.53812	6.98035
1K	U.S.C. FURNACE “K”	33,763.42	0.93656	3.91957
1L	U.S.C. FURNACE “L”	38,262.15	0.94797	4.03366
1M	U.S.C. FURNACE “M”	65,956.51	1.47987	6.39789
1N	U.S.C. FURNACE “N”	79,494.67	1.51480	6.74719
3A	V.M.R. FURNACE “A”	23,890.20	0.63394	2.66913
3B	V.M.R. FURNACE “B”	21,607.98	0.62830	2.61266
5A	STEAM S. HEATER “A”	42,465.62	0.76678	3.45000
5B	STEAM S. HEATER “B”	45,573.02	0.77464	3.52861
9A	SOUTH DECOKING CYCLONE	596.93	0.00000	0.00000
9B	NORTH DECOKING CYCLONE	424.04	0.00000	0.00000
FUG	Fugitive Emissions	0.01	-	9.03384
MSS	Flare MSS Emissions	1,563.68	0.00447	5.36665
	Total	1,050,827	20.346	104.6521
	CO_2 Equivalent [1]	1,050,827	6,307.397	2,198

Total Mass GHG Emissions	**1,050,952**	**tpy**
Total CO_2 Equivalent Emissions	**1,059,332**	**tpy**

Note:

1. CO_2 equivalent emissions are based on the following Global Warming Potentials (GWP)

GHG	GWP
CO_2	1
N_2O	310
CH_4	21

2. Underlying data in this table may not be accurate to the apparent number of significant digits.

Table A-2
Heater GHG Emissions
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

Source	Description	Fuel	Heat Input (MMBtu/hr)	Flow Rate (scf/hr)	Annual Operating Hours (hr/yr)	Emission Factor (kg/MMBtu) [1]		CO_2 Emissions	N_2O Emissions	CH_4 Emissions
						N_2O	CH_4	tpy	tpy	tpy
1A	U.S.C. FURNACE “A”	Fuel Gas	188.00	183,044.36	8,760	0.0006	0.003	93,838	1.089	5.446
1B	U.S.C. FURNACE “B”	Fuel Gas	188.00	183,044.36	8,760	0.0006	0.003	93,838	1.089	5.446
1C	U.S.C. FURNACE “C”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
1D	U.S.C. FURNACE “D”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
1E	U.S.C. FURNACE “E”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
1F	U.S.C. FURNACE “F”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
1G	U.S.C. FURNACE “G”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
1H	U.S.C. FURNACE “H”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
1J	U.S.C. FURNACE “J”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
1K	U.S.C. FURNACE “K”	Fuel Gas	188.00	183,044.36	8,760	0.0006	0.003	93,838	1.089	5.446
1L	U.S.C. FURNACE “L”	Fuel Gas	188.00	183,044.36	8,760	0.0006	0.003	93,838	1.089	5.446
1M	U.S.C. FURNACE “M”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
1N	U.S.C. FURNACE “N”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
3A	V.M.R. FURNACE “A”	Fuel Gas	126.70	123,360.21	8,760	0.0006	0.003	63,241	0.734	3.670
3B	V.M.R. FURNACE “B”	Fuel Gas	126.70	123,360.21	8,760	0.0006	0.003	63,241	0.734	3.670
5A	STEAM S. HEATER “A”	Fuel Gas	145.60	141,762.01	8,760	0.0006	0.003	72,675	0.844	4.218
5B	STEAM S. HEATER “B”	Fuel Gas	145.60	141,762.01	8,760	0.0006	0.003	72,675	0.844	4.218

Notes:

1. CO2 emissions calculated by Eq. C-5 from 40 CFR Part 98 Chapter C
2. N_2O and CH_4 emission factors are from 40 CFR 98, Table C-2
3. Underlying data in this table may not be accurate to the apparent number of significant digits.

Table A-3
Heater GHG Emissions
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

CO Molecular Weight: 28.01 lb/lbmol
CO2 Molecular Weight: 44.01 lb/lbmol
Amount of coke burned results in CO2: 75% mol%
Amount of coke burned results in CO: 25% mol%

EPN	Source	Description	CO Emission Factor (lb/decoke)	Number of Decokes per Year	CO_2 Emissions
					tpy
9B	1A	U.S.C. FURNACE “A”	870.26	14	29.12
9B	1B	U.S.C. FURNACE “B”	870.26	14	29.12
9B	1C	U.S.C. FURNACE “C”	870.26	14	29.12
9B	1D	U.S.C. FURNACE “D”	2809.46	18	115.87
9B	1E	U.S.C. FURNACE “E”	2809.46	18	115.87
9B	1F	U.S.C. FURNACE “F”	2809.46	18	115.87
9A	1G	U.S.C. FURNACE “G”	2809.46	18	115.87
9A	1H	U.S.C. FURNACE “H”	2809.46	18	115.87
9A	1J	U.S.C. FURNACE “J”	2809.46	18	115.87
9A	1K	U.S.C. FURNACE “K”	2809.46	18	115.87
9A	1L	U.S.C. FURNACE “L”	870.26	14	29.12
9A	1M	U.S.C. FURNACE “M”	2809.46	18	115.87
9A	1N	U.S.C. FURNACE “N”	2809.46	18	115.87
9B	3A	V.M.R. FURNACE “A”	1330.73	18	54.89
9B	3B	V.M.R. FURNACE “B”	1330.73	18	54.89

Notes:
1. CO2 emissions calculated by Eq. C-5 from 40 CFR Part 98 Chapter C
2. N_2O and CH_4 emission factors are from 40 CFR 98, Table C-2
3. Underlying data in this table may not be accurate to the apparent number of significant digits.

Table A-4
Flare GHG Emissions
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

Source	Description	Temperature at Actual Conditions (°F)	Absolute Pressure at Actual Conditions (psia)	Volume Gas Sent to Flare (acf/yr)	Gas LHV (Btu/scf)	Flare Combustion Efficiency [1]	Mole Fraction in Gas to Flare		Mole Fraction of Gas Hydrocarbon Constituents [2]					Volume Gas Sent to Flare (scf/yr) [6]	Annual Emissions (acf/yr)			GHG Volumetric Emissions (scf/yr) [6]			GHG Mass Emissions (tpy) [7]			CO_2 Emissions	N_2O Emissions	CH_4 Emissions
							CH_4	CO_2	Methane	Ethane	Propane	Butanes	Pentanes-plus		CH_4 Un-Combusted [3]	CO_2 Un-Combusted [4]	CO_2 Combusted [5]	CH_4 Un-Combusted	CO_2 Un-Combusted	CO_2 Combusted	CH_4 Un-Combusted	CO_2 Un-Combusted	CO_2 Combusted	tpy	tpy [8]	tpy
MSS	Olefins Startup	60	14.7	9,690,533	1099.98	0.98	0.29	0.00	0.29	0.08	0.001	0.01	0.002	9,690,533	57,148	0.000	4,716,345	57,148	0	4,716,345	2.658	0.000	273.463	273.46	0.001	2.66
MSS	Olefins Shutdown	60	14.7	5,587,779	1719.29	0.98	0.17	0.00	0.17	0.17	0.18	0.06	0.01	5,587,779	18,727	0.000	7,217,506	18,727	0	7,217,506	0.871	0.000	418.485	418.48	0.001	0.87
MSS	Process Equipment and Vessel Maintenance	60	14.7	11,783,761	1719.29	0.98	0.17	0.00	0.17	0.17	0.18	0.06	0.002	11,783,761	39,493	0.000	15,034,613	39,493	0	15,034,613	1.837	0.000	871.735	871.74	0.002	1.84

Notes:

1. Default value is 0.98.
2. Use representative composition determined by engineering calculation based on process knowledge and best available data.
3. Eq. W-19 from 40 CFR 98
4. Eq. W-20 from 40 CFR 98
5. Eq. W-21 from 40 CFR 98
6. Eq. W-34 from 40 CFR 98
7. Modified Eq. W-36 from 40 CFR 98. GHG Mass Emissions (tpy) = GHG Volumetric Emissions (scf/yr) * Density of GHG (kg/ft ^{3}) / 907.18 (kg/ton); where CO_2 density is 0.0526 kg/ft^3, and CH_4 density is 0.0422 kg/ft^3
8. Modified Eq. W-40 from 40 CFR 98. N_2O emissions (tpy) = Fuel (scf/yr) * HHV (Btu/scf) / 10^6 (Btu/MMBtu) * EF (kg/MMBtu) / 907.18 (kg/ton); where EF = 1×10^{-4} kg N_2O/MMBtu
9. In the table above, "tpy" represents short tons per year.
10. Underlying data in this table may not be accurate to the apparent number of significant digits.

Table A-5
Fugitive Emission Summary EPN: FUG
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

Stream ID	14420		14216		14230		14195		14223		14404	
Total Emission Rate (lb/hr)	0.283812		0.249564		0.101712		0.147852		0.147852		0.147852	
Copmonent	wt%	lb/hr	wt%	lb/hr	wt%	lb/hr	wt%	lb/hr	wt%	lb/hr	wt%	lb/hr
Carbon Dioxide	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Methane	80.41%	0.2282	64.25%	0.1604	82.10%	0.0835	64.30%	0.0951	97.02%	0.1435	79.66%	0.1178

Stream ID	14480		Fuel 6		14170		14010		3700R		14342	
Total Emission Rate (lb/hr)	0.90		0.15		0.42		0.42		0.38		0.07	
Copmonent	wt%	lb/hr	wt%	lb/hr	wt%	lb/hr	wt%	lb/hr	wt%	lb/hr	wt%	lb/hr
Carbon Dioxide	0.00%	0.0000	0.85%	0.0013	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Methane	80.41%	0.7230	94.15%	0.1392	11.81%	0.0496	3.11%	0.0131	11.34%	0.0433	71.11%	0.0529

Stream ID	14368		14310		14358		Ethylene		Total	
Total Emission Rate (lb/hr)	0.13		1.25		0.20		1.22		1.08	
Copmonent	wt%	lb/hr	wt%	lb/hr	wt%	lb/hr	wt%	lb/hr	lb/hr	tpy
Carbon Dioxide	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.0013	0.0055
Methane	68.25%	0.0867	0.00%	0.0001	64.69%	0.1263	0.00%	0.0000	2.0625	9.0338

Note: Underlying data in this table may not be accurate to the apparent number of significant digits. Emissions in lb/hr are shown with four digits after the decimal point so that smaller numbers show up as non-zero values.

Table A-6
Fugitive Emission Calculations EPN: FUG
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

Component Type	Stream Type	Emission Factor SOCMI w/o C2=	<11% Ethylene Component Count								Emission Factor SOCMI Avg	11% to 85% Ethylene Component Count							Emission Factor SOCMI w/ C2=	100% Ethylene Component Count	Control Efficiency 28VHP	Hours 8,760	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
			14420	14216	14230	14195	14223	14404	14480	Fuel 6		14170	14010	3700R	14342	14368	14310	14358						
Valves	Gas/Vapor	0.0089	34	30	16	14	14	14	120	14	0.0132	24	24	40	8	12	138	14	0.0258	57	97%	8,760	0.215	0.944
	Light Liquid	0.0035	21	9	0	9	9	9	0	9	0.0089	15	15	40	8	20	12	9	0.0459	44	97%	8,760	0.099	0.435
	Heavy Liquid	0.0007	0	0	0	0	0	0	0	0	0.0005	0	0	0	0	0	9	0	0.0005	0	0%	8,760	0.005	0.020
Pumps	Light Liquid	0.0386	0	0	0	0	0	0	0	0	0.0439	0	0	0	0	0	0	0	0.144	2	85%	8,760	0.043	0.189
	Heavy Liquid	0.0161	0	0	0	0	0	0	0	0	0.019	0	0	0	0	0	0	0	0.0046	0	0%	8,760	0.000	0.000
Flanges	Gas/Vapor	0.0029	120	111	48	63	63	63	390	63	0.0039	138	138	114	22	35	419	63	0.0053	158	30%	8,760	4.992	21.865
	Light Liquid	0.0005	63	24	0	24	24	24	0	24	0.0005	46	46	126	26	61	37	24	0.0052	127	30%	8,760	0.654	2.866
	Heavy Liquid	0.00007	0	0	0	0	0	0	0	0	0.00007	0	0	0	0	0	24	0	0.00007	0	30%	8,760	0.001	0.005
Compressors	Gas/Vapor	0.5027	0	0	0	0	0	0	1	0	0.5027	0	0	0	0	0	0	0	0.5027	0	85%	8,760	0.075	0.330
Relief Valves	Gas/Vapor	0.2293	1	1	0	1	1	1	0	1	0.2293	2	2	0	0	0	5	1	0.2293	3	97%	8,760	0.131	0.572
	Light Liquid	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%	8,760	0.000	0.000
	Heavy Liquid	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%	8,760	0.000	0.000
Open Ends		0.004	0	0	0	0	0	0	0	0	0.0038	0	0	0	0	0	0	0	0.0075	0	97%	8,760	0.000	0.000
Sample Con.	Gas/Vapor	0.033	0	0	0	0	0	0	0	0	0.033	0	0	0	0	0	0	0	0.033	0	97%	8,760	0.000	0.000
Sample Con.	Light Liquid	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	97%	8,760	0.000	0.000
Sample Con.	Heavy Liquid	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	97%	8,760	0.000	0.000
																						Total	**6.22**	**27.23**

Notes:

1. Emission Factors based on TCEQ's Air Permit Technical Guidance Package for Chemical Sources: Equipment Leak Fugitives, Uncontrolled SOCMI Fugitive Emission Factors, dated October 2000.

2. Percent reduction based on TCEQ's Air Permit Technical Guidance Package for Chemical Sources: Equipment Leak Fugitives, Control Efficiencies for TNRCC Leak Detection and Repair Programs, dated October 2000.

Appendix B

RBLC Database Search Results

Appendix B

RBLC Database Search Results for GHG Emissions from Furnaces and Heaters

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Startup Heater	Natural gas	110.12	MMBTU/hr	Carbon Dioxide	good combustion practices	117	LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Startup Heater	Natural gas	110.12	MMBTU/hr	Carbon Dioxide Equivalent (CO2e)	good combustion practices	638	TONS/YR
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Startup Heater	Natural gas	110.12	MMBTU/hr	Methane	good combustion practices	0.0023	LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Startup Heater	Natural gas	110.12	MMBTU/hr	Nitrous Oxide (N2O)	good combustion practices	0.0006	LB/MMBTU
*MN-0085	CARGILL, INCORPORATED	CARGILL, INCORPORATED	MN		INDURATING FURNACE	Natural gas	542	MMBTU/H	Carbon Dioxide		710000	TON/YR

RBLC Database Search Results for GHG Emissions from Boilers

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT
*FL-0330	PORT DOLPHIN ENERGY LLC		FL	DPA-EPA-R4001	Boilers (4 - 278 mmbtu/hr each)	Natural gas	0		Carbon Dioxide	tuning, optimization, instrumentation and controls, insulation, and turbulent flow.	117	LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Auxiliary Boiler	Natural gas	472.4	MMBTU/hr	Carbon Dioxide	good combustion practices	117	LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Auxiliary Boiler	Natural gas	472.4	MMBTU/hr	Carbon Dioxide Equivalent (CO2e)	good combustion practices	51748	TONS/YR
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Auxiliary Boiler	Natural gas	472.4	MMBTU/hr	Methane	good combustion practices	0.0023	LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Auxiliary Boiler	Natural gas	472.4	MMBTU/hr	Nitrous Oxide (N2O)	good combustion practices	0.0006	LB/MMBTU
AL-0231	NUCOR DECATUR LLC	NUCOR CORPORATION	AL	712-0037	VACUUM DEGASSER BOILER	Natural gas	95	MMBTU/H	Carbon Dioxide		0.061	LB/MMBTU
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	PSD-LA-752	AUXILIARY BOILER (AUX-1)	Natural gas	338	MMBTU/H	Carbon Dioxide	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	117	LB/MMBTU
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	PSD-LA-752	AUXILIARY BOILER (AUX-1)	Natural gas	338	MMBTU/H	Methane	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0022	LB/MMBTU
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	PSD-LA-752	AUXILIARY BOILER (AUX-1)	Natural gas	338	MMBTU/H	Nitrous Oxide (N2O)	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0002	LB/MMBTU
SC-0113	PYRAMAX CERAMICS, LLC	PYRAMAX CERAMICS, LLC	SC	0160-0023	BOILERS	Natural gas	5	MMBTU/H	Carbon Dioxide	CONTROL METHOD FOR CO2E: GOOD DESIGN AND COMBUSTION PRACTICES.		
*NE-0054	CARGILL, INCORPORATED	CARGILL, INCORPORATED	NE		Boiler K	Natural gas	300	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	good combustion practices		
*MN-0085	CARGILL, INCORPORATED	CARGILL, INCORPORATED	MN		INDURATING FURNACE	NATURAL GAS	542	MMBTU/H	Carbon Dioxide		710000	TON/YR

Appendix B Continued

RBLC Database Search Results for GHG Emissions from Flares

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Ammonia Flare	natural gas	0.4	MMBTU/hr	Carbon Dioxide	work practice/good combustion practices		
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Ammonia Flare	natural gas	0.4	MMBTU/hr	Carbon Dioxide Equivalent (CO2e)	work practice/good combustion practices		
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Ammonia Flare	natural gas	0.4	MMBTU/hr	Methane	work practice/good combustion practices		
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Ammonia Flare	natural gas	0.4	MMBTU/hr	Nitrous Oxide (N2O)	work practice/good combustion practices		
*AK-0076	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	AQ1201CPT01	Combustion (Flares)	Fuel Gas	35	MMscf/yr	Carbon Dioxide	Good Combustion Practices		
*AK-0076	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	AQ1201CPT01	Combustion (Flares)	Fuel Gas	35	MMscf/yr	Carbon Dioxide	Good Combustion Practices		
LA-0257	SABINE PASS LNG TERMINAL	SABINE PASS LIQUEFACTION, LL	LA	PSD-LA-703(M3)	Marine Flare	natural gas	1590	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	2909	TONS/YR
LA-0257	SABINE PASS LNG TERMINAL	SABINE PASS LIQUEFACTION, LL	LA	PSD-LA-703(M3)	Wet/Dry Gas Flares (4)	natural gas	0.26	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	133	TONS/YR

RBLC Database Search Results for GHG Emissions from Fugitives

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT
OH-0281	RUMPKE SANITARY LANDFILL, INC	RUMPKE SANITARY LANDF	OH	14-05824, 14-05292	NEW SOLID WASTE DISPOSAL WITH LANDFILL GAS GENERATION		42760000	TONS OF WASTE-EXPANS	Methane	ACTIVE GAS COLLECTION AND CONTROL SYSTEM: FLARE; LANDFILL GAS RECOVERY FOR SALE/USE; OR CONTROL BY A THERMAL OXIDIZER	1563	T/YR
OH-0281	RUMPKE SANITARY LANDFILL, INC	RUMPKE SANITARY LANDF	OH	14-05824, 14-05292	EXISTING SOLID WASTE DISPOSAL WITH LANDFILL GAS GENERATION		32272000	TONS OF WASTE	Methane	ACTIVE GAS COLLECTION AND CONTROL SYSTEM: FLARE; LANDFILL GAS RECOVERY FOR SALE/USE; OR CONTROL BY A THERMAL OXIDIZER	599	T/YR
OH-0281	RUMPKE SANITARY LANDFILL, INC	RUMPKE SANITARY LANDFILL, INC	OH	14-05824, 14-05292	FUGITIVE EMISSIONS FROM LANDFILL AND GAS COLLECTION SYSTEM				Methane		45029	T/YR
TX-0481	AIR PRODUCTS BAYTOWN I I	AIR PRODUCTS LP	TX	PSD-TX-1044 / 35873	FUGITIVES (4)				Carbon Monoxide		7.85	LB/H

Appendix C

Copy of TCEQ Air Permit Application