PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION

GREENHOUSE GAS EMISSIONS

EQUISTAR CHEMICALS, L.P. ▪ CHANNELVIEW SITE

CHANNELVIEW NORTH - METHANOL UNIT RESTART

TCEQ PERMIT NUMBER 8125

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June 2012

Project 114402.0078

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1 EXECUTIVE SUMMARY

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

- North Plant operated by Equistar Chemicals, LP (RN: 100542281, CN: 600124705), and
- South Plant operated by Lyondell Chemical Company (RN: 100633650, CN: 600344402).

For the purpose of federal regulatory applicability, the North and South Plants are contiguous and under common control and hence considered as one site in this permit application. The combined Channelview Site is an existing major source, located in the Houston-Galveston-Brazoria (HGB) area. The site is a major source of volatile organic compounds (VOC), sulfur dioxide (SO_2), carbon monoxide (CO), both nitrogen dioxide (NO_2) and nitrogen oxides (NO_X), particulate matter (PM), hazardous air pollutants (HAPs), and greenhouse gases (GHGs). The HGB area is currently classified as a severe nonattainment area for ozone and an attainment or unclassified area for all other criteria pollutants.[1]

The Channelview North Plant is authorized to produce Highly Purified Isobutylene (HPIB) and store/load methanol under Texas Commission on Environmental Quality (TCEQ) New Source Review (NSR) Permit No. 8125. A brief history of NSR Permit No. 8125 is provided below:

> This permit was initially issued on January 13, 1984 to authorize a methanol (MeOH) production unit. The June 2006 amendment project transformed the permit from one regulating a methanol production unit to a unit that could either produce methanol or purify isobutylene (IBP). With the May 2009 renewal, the authorization to produce methanol was removed from this permit and the site dedicated its resources to IBP production. The MeOH reformer and cooling tower were removed from the permit. The site plans to discontinue production of HPIB, at the north plant and return the associated equipment to methanol service.

With this permit amendment application; Equistar is proposing to restart the methanol unit (MeOH Restart Project) at the Channelview North Plant. As part of the MeOH Restart Project, Equistar is proposing to transfer the existing equipment from HPIB production back to MeOH production. The production of HPIB will be transferred to the Channelview South Plant and authorized under NSR Permit No. 19155. The transfer of HPIB production to the Channelview South Plant production is addressed separately in a permit amendment application for NSR Permit No. 19155.

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[1] The United States Protection Agency (U.S. EPA) Green Book. Source: http://www.epa.gov/oar/oaqps/greenbk/, accessed August 2011

With this submittal, Equistar is requesting issuance of a PSD permit for Greenhouse Gas (GHG) emissions. The project will include the following additions and modifications to the MeOH production unit which impact GHG emissions.

- New MeOH Reformer Furnace (EPN: EHTF7001);
- Modification and addition of equipment components (fugitive emissions) in VOC service (EPN: EFUGMEOH);
- Addition of MeOH process vents and maintenance, startup, and shutdown streams to a new flare (EPN: EMEOHFLARE);
- Addition of an emergency only flare (EMERFLARE); and
- Modification to loading operations controlled by an existing flare (EPN: 17E01).

The combined Channelview Site is an existing major source of GHG emissions, with GHG emissions greater than 100,000 tons/year of CO_2e. The estimated GHG emissions associated with the proposed MeOH Restart Project are above the GHG major modification threshold of 75,000 tons/year of CO_2e. Therefore, the proposed MeOH Restart Project will also trigger Federal PSD review for GHG emissions.

All required supporting documentation for the permit amendment is provided in this application. TCEQ Form PI-1 is included in Section 2 of this application. An area map indicating the site location and a plot plan identifying the location of various sources throughout the site are included in Sections 3 and 4 of the report, respectively. A process description and process flow diagram are presented in Sections 5 and 6, respectively. Emission calculations are provided in Section 7 of this application.

Detailed federal regulatory requirements including the New Source Review Analysis relating to the MeOH Restart Project are provided in Section 8. Discussions of Best Available Control Technology (BACT) is provided in Section 9. A material balance table is located in Section 10.

2 TCEQ FORMS

PI-1 FORM

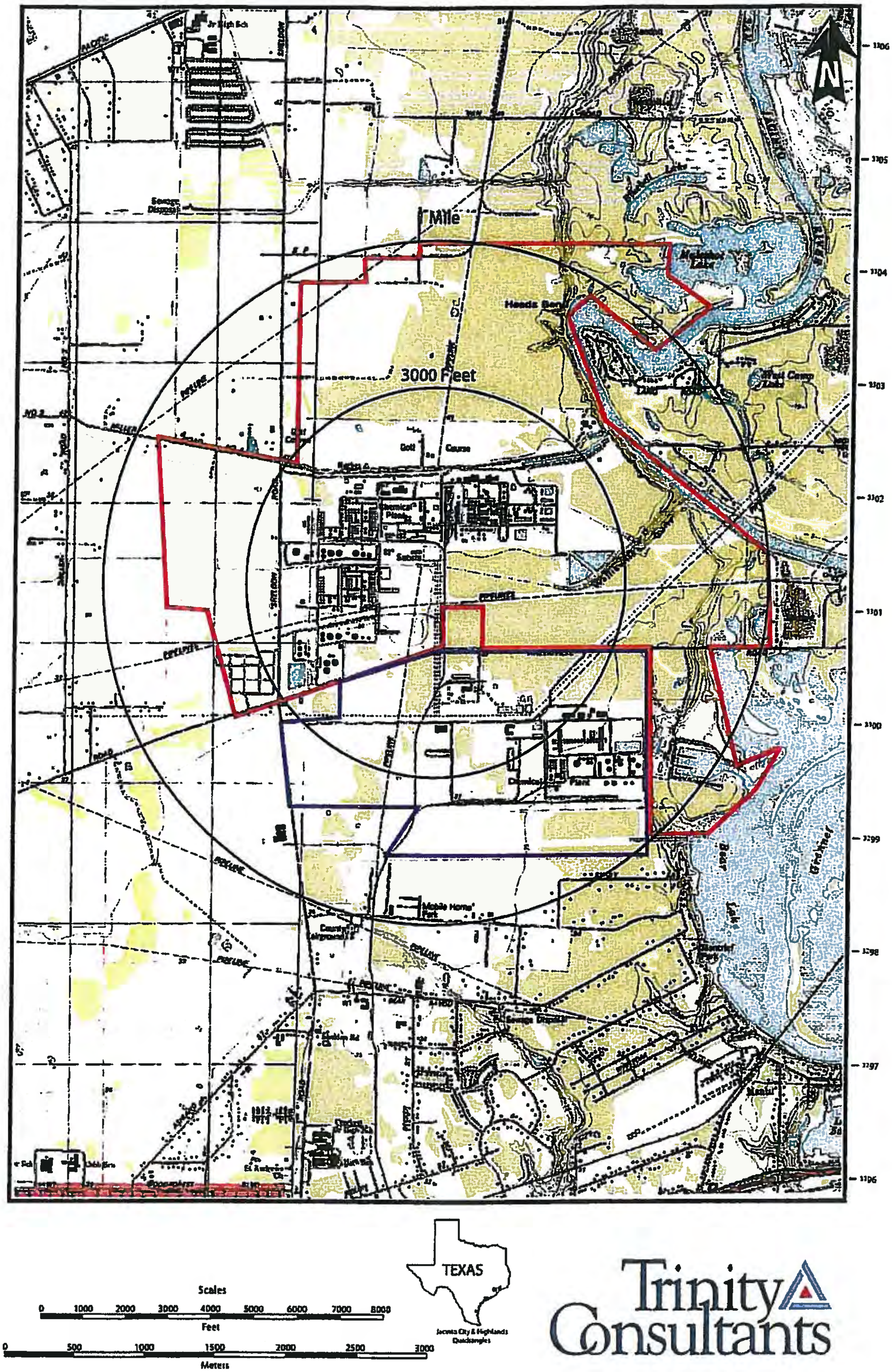
Texas Commission on Environmental Quality
Form PI-1 General Application for Air Preconstruction Permit and Amendment

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

I. Applicant Information		
A. Company or Other Legal Name: Equistar Chemicals, LP		
Texas Secretary of State Charter/Registration Number (*if applicable*):		
B. Company Official Contact Name: Michael VanDerSnick		
Title: Environmental Manager		
Mailing Address: P.O. Box 777		
City: Channelview	State: TX	ZIP Code: 77530
Telephone No.: 281-860-5150	Fax No.: 281-862-4099	E-mail Address: Michael.VanDerSnick@lyondellbasell.com
C. Technical Contact Name: Thomas Warnement		
Title: Senior Environmental Representative		
Company Name: Equistar Chemicals, LP		
Mailing Address: P.O. Box 777		
City: Channelview	State: TX	ZIP Code: 77530
Telephone No.: 281-860-1272	Fax No.: 281-452-8825	E-mail Address: tom.warnement@lyondellbasell.com
D. Site Name: Channelview Plant		
E. Area Name/Type of Facility: Methanol Production Unit		☒ Permanent ☐ Portable
F. Principal Company Product or Business: SOCMI		
Principal Standard Industrial Classification Code (SIC):2869		
Principal North American Industry Classification System (NAICS): 325110		
G. Projected Start of Construction Date: July 1, 2012		
Projected Start of Operation Date: February 15, 2013		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 8280 Sheldon Road, Building 1		
City/Town: Channelview	County: Harris	ZIP Code: 77530
Latitude (nearest second): 95°06'47" W	Longitude (nearest second): 29°50'7" N	

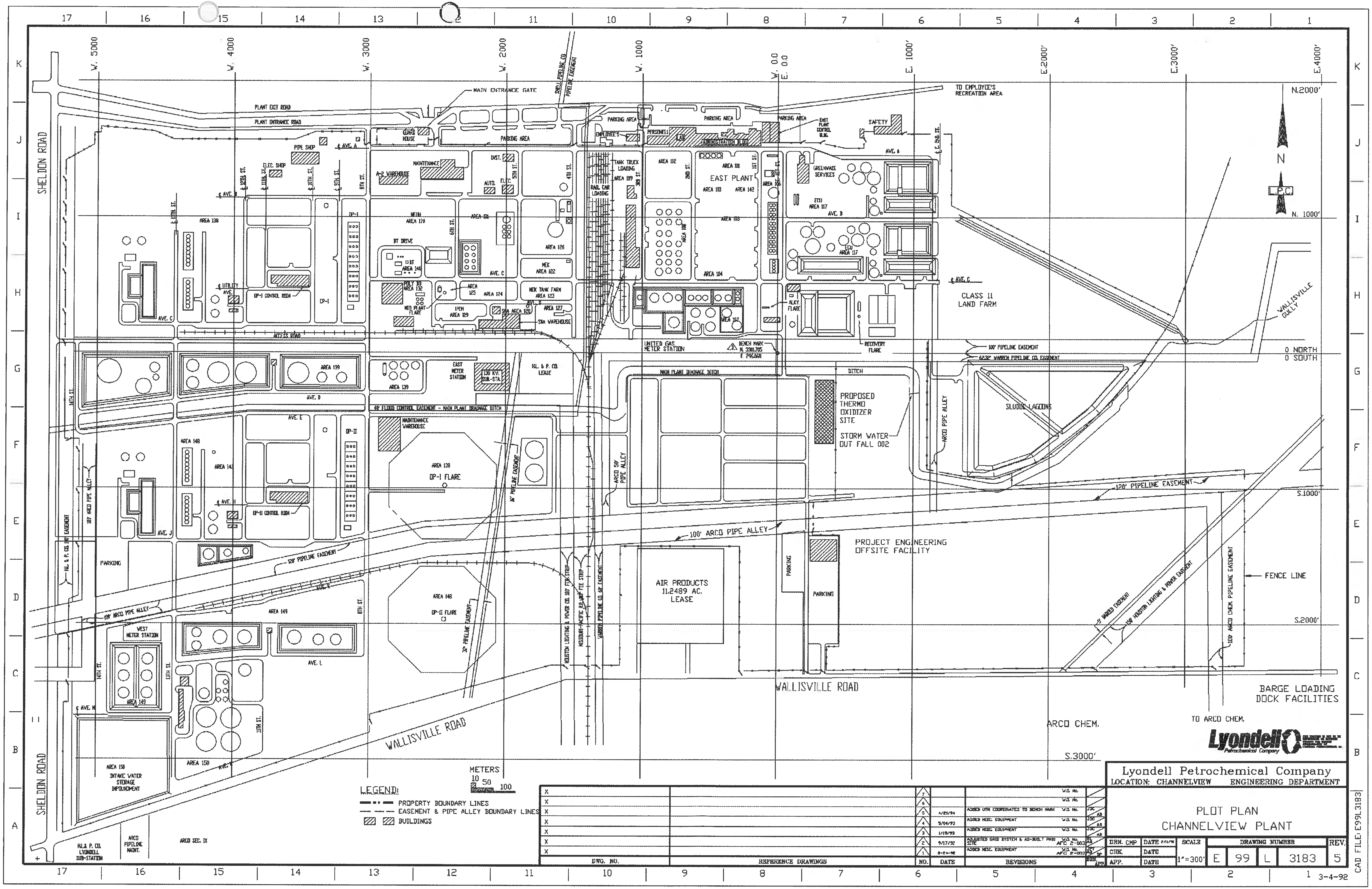
3 AREA MAP

LyondellBasell Channelview Fa[illegible]ity



Trinity Consultants

4 PLOT PLAN



LEGEND:

- PROPERTY BOUNDARY LINES
- EASEMENT & PIPE ALLEY BOUNDARY LINES
- ▨ ▨ BUILDINGS

DWG. NO.	REFERENCE DRAWINGS	NO.	DATE	REVISIONS		DRN. APP.
X		7			W.O. No.	
X		6			W.O. No.	
X		5	4/21/94	ADDED UTM COORDINATES TO BENCH MARK	W.O. No.	JJC AB
X		4	5/04/93	ADDED MISC. EQUIPMENT	W.O. No.	JJC AB
X		3	1/19/93	ADDED MISC. EQUIPMENT	W.O. No.	JJC AB
X		2	9/17/92	ADJUSTED GRID SYSTEM & AS-BUILT PMDI SITE	W.O. No. AFC 2-003	[illegible] AB
X		1	8-24-92	ADDED MISC. EQUIPMENT	W.O. No. AFC 2-003	[illegible]

Lyondell Petrochemical Company
LOCATION: CHANNELVIEW ENGINEERING DEPARTMENT

PLOT PLAN
CHANNELVIEW PLANT

DRN. CMP	DATE 2/11/92	SCALE	DRAWING NUMBER			REV.
CHK.	DATE	1"=300'	E	99	L 3183	5
APP.	DATE					

CAD FILE: E99L3183

3-4-92

5 PROCESS DESCRIPTION

The rated capacity of the Channelview MeOH process unit is approximately 273 million gallons of high purity methanol per year using light hydrocarbon (normally natural gas) as a feedstock. The unit also has the capability of injecting carbon dioxide as a supplemental feed.

The feedstock is compressed, preheated, and pretreated to remove sulfur and chlorine compounds. The treated feed is then mixed with steam before being sent to the reformer.

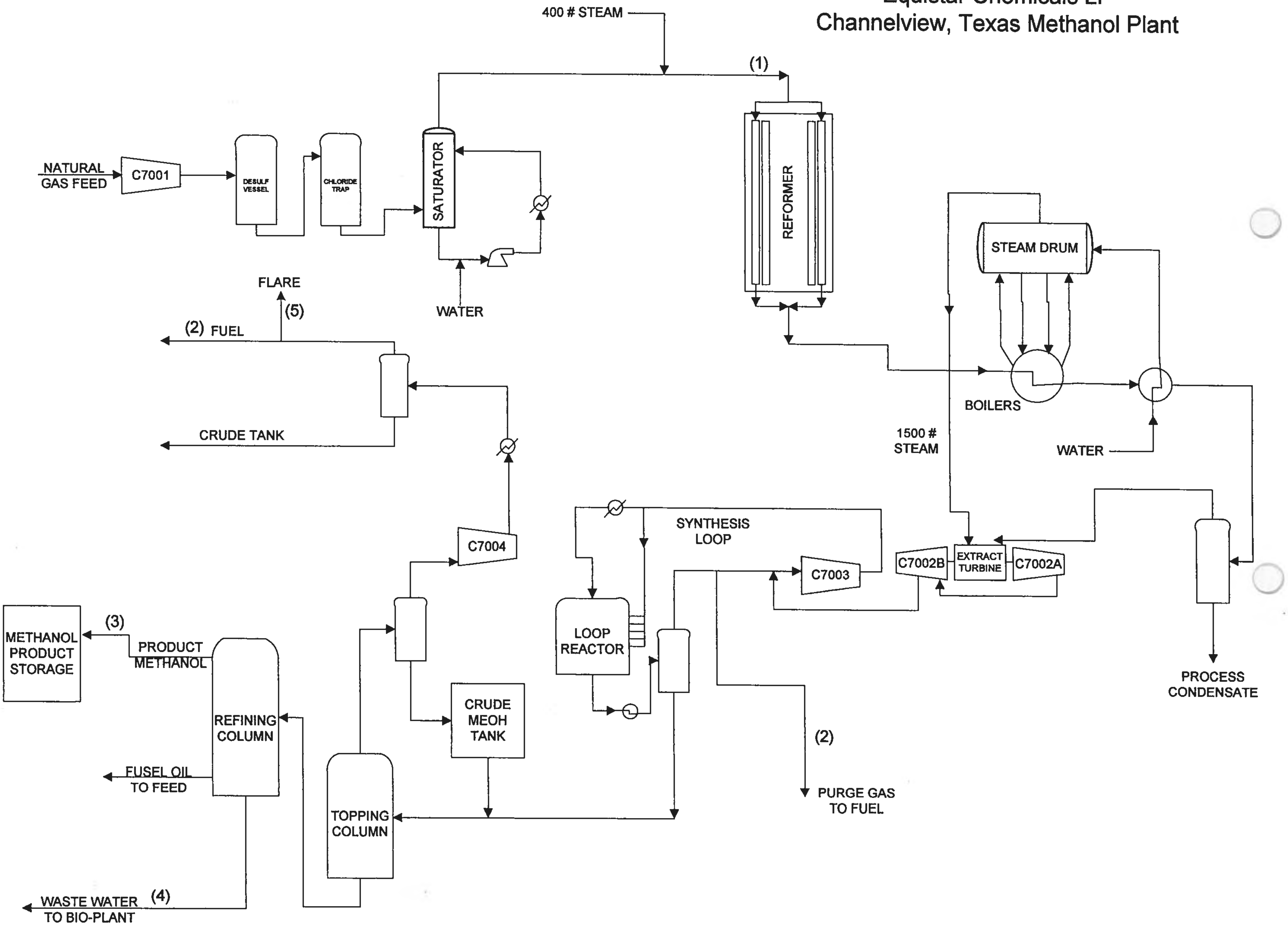
The reformer consists of a large number of catalyst-filled tubes suspended in the radiant section of a process heater. The process stream containing light hydrocarbons and steam flows into the tubes where it is heated to reaction temperature to produce the synthesis gas.

Steam required to operate the unit is produced from waste heat in the reformer. The synthesis gas is cooled, compressed, reheated, and sent to the conversion reactor. The converter effluent is cooled with the crude methanol, separated as a liquid phase, and sent to product purification. The off-gas is recycled to the methanol converter. The purge gas is used as fuel in the reformer fuel gas.

Light ends are removed in the topping column from the crude methanol and used as fuel in the reformer. The topped product is sent to a refining column, where the high purity methanol is removed as the overhead stream, cooled and sent to storage tanks and the bottom stream consisting of water with a trace of hydrocarbons is sent to on-site wastewater treatment. A refining column side stream containing water and mixed alcohol is returned to the process.

6 PROCESS FLOW DIAGRAM

Equistar Chemicals LP
Channelview, Texas Methanol Plant



This section contains a summary of the GHG emission rates for all affected sources in the MeOH Restart Project.

7.1 GREENHOUSE GAS (GHG) EMISSIONS

Detailed calculations are included in Appendix A.

TABLE 7-1. GHG EMISSIONS

EPN	Description	CO_2e tons/yr
EHTF7001	Reformer Furnace	827,411
17E01	Loading Operations (Flare)	39
EMEOHFLARE	Methanol Flare	3,755
EEMERFLARE	Emergency Flare	181
EFUGMEOH	Fugitive Emissions	139
	Total	**831,526**

8 NEW SOURCE REVIEW ANALYSIS

8.1 PREVENTION OF SIGNIFICANT DETERIORATION (PSD) REGULATIONS

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

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

1. Determine the emission increases from the proposed projects.

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

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

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

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

   An emission increase is the amount by which the new level of “actual emissions” at the emissions unit exceeds the old level. The new level of “actual emissions” is the proposed permitted emission rate after the modification. The old level of “actual emissions” is calculated based on the average of any 24-month period of operation, which occurred within 10 years preceding the modification. No existing source that emits CO_2e is being modified; all CO_2e project increases come from new sources. Therefore, the baseline is equal to zero.

4. Determine net emission increase.

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

8.1.1 APPLICABILITY ANALYSIS

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

TABLE 8-1. PSD APPLICABILITY SUMMARY

	CO_2e (tpy)
Project Emission Increase (tpy)	831,526
PSD Significant Emission Rate (tpy)[1]	75,000
PSD Review Required? [2]	YES

[1] The Channelview site is a existing major source.

[2] If Proposed Emissions from MeOH Restart Project (tpy) < PSD Significant Emission Rate (tpy) → NO
If Proposed Emissions from MeOH Restart Project (tpy) > PSD Significant Emission Rate (tpy) → YES

8.1.2 BACT REVIEW

PSD regulations require Best Available Control Technology (BACT) review for all equipment that is physically or operationally modified. The following emission sources of GHG are being physically or operationally modified as part of this project: methanol reformer furnace, fugitive emissions, and emissions from flares. Therefore, federal BACT review does apply. BACT requirements are addressed in Section 9 of this application.

8.1.3 AIR QUALITY ANALYSIS

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

9 BEST AVAILABLE CONTROL TECHNOLOGY

9.1 EXECUTIVE SUMMARY

Greenhouse Gas (GHG) Best Available Control Technology (BACT) for the methanol unit restart has been evaluated via a "top-down" five-step approach. Each of those five steps is outlined in subsequent sections of this document. The analysis has been conducted on each source for each GHG gas emitted. That analysis led to the conclusion that:

> BACT for the reformer furnace GHG emissions is fuels management (limits CO_2, CH_4). The company also adopts an energy efficient design (limits CO_2, CH_4 and N_2O), and proper operational control (limits CO_2, CH_4).
>
> BACT for the flare is use of a current flare design meeting requirements of 40 CFR §60.18 (CH_4), waste gas minimization (CO_2, CH_4, N_2O), and use of low carbon intensity gas fired pilots (CO_2).
>
> BACT for fugitive emissions has been determined to be instrumented leak detection and repair for methane rich streams (limits CH_4) and visual, olfactory and auditory inspection for CO_2 rich streams.

9.2 INTRODUCTION

GHG emissions increases from the methanol unit restart, expressed as carbon dioxide equivalents (CO2e) are projected to be greater than 100,000 tons which triggers PSD permitting obligations as described in EPA's Greenhouse Gas Tailoring Rule. Emissions of GHGs are more than 99% carbon dioxide (CO_2) expressed as carbon dioxide equivalents (CO2e). Pursuant to EPA regulation, the project is subject to regulation under PSD and the required BACT review has been conducted for each of the GHG pollutants individually from each of the emissions sources. In the proposed project, specified GHGs will be emitted from the following sources, and no other GHGs (i.e., SF_6, hydrofluorocarbons, perfluorocarbons) will be emitted from the methanol unit beyond those indicated below:

- Reformer Furnace (CO_2, N_2O and CH_4)
- Flares (CO_2, N_2O, CH_4)
- Fugitive Emissions (CH_4)

CO_2, CH_4, and N_2O will be generated as a result of hydrocarbon combustion within the reformer furnace and at the flare. CH_4 will be emitted as fugitive emissions from components in feedstock, process and fuel gas services.

Permitting of GHGs is a relatively new requirement and there is not yet much guidance specific to GHG BACT evaluations and determinations. The following US EPA guidance documents were utilized as resources in completing the GHG BACT evaluation for the proposed project:

PSD and Title V Permitting Guidance for Greenhouse Gases (hereafter referred to as General GHG Permitting Guidance)[2]

Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boiler (hereafter referred to as GHG BACT Guidance for Boilers)[3]

Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Petroleum Refining Industry (hereafter referred to as GHG BACT Guidance for Refineries)[4]

To complete the GHG BACT evaluation, Equistar also reviewed and/or relied on a number of other resources. Some of those resources form much of the basis for this BACT analysis. Examples of the variety of those resources which were consulted are listed below while others are indicated throughout this document:

NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, 1990[5]

RBLC database – Searching the newly enhanced RBLC database returned no results on permitting decisions for gaseous fuel and gaseous fuel mixture combustion in Process Code 11.300, synthetic organic chemical manufacturing industry (SOCMI), in Process Code 64.000, or flares in Process Code 19.300. [6]

Herzog, Meldon, Hatton, "*Advanced Post-Combustion CO2 Capture*," April 2009[7]

US EPA, "*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial and Institutional Boilers*," October 2010.[8]

Report of the Interagency Task Force on Carbon Capture and Storage, August 2010.[9]

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

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

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

[5] http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf

[6] http://cfpub.epa.gov/RBLC/

[7] http://web.mit.edu/mitei/docs/reports/herzog-meldon-hatton.pdf

[8] http://www.epa.gov/nsr/ghgdocs/iciboilers.pdf

[9] http://www.fe.doe.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf

Stewart Mehlman, “*Carbon Capture and Sequestration (via Enhanced Oil Recovery) from a Hydrogen Production Facility in an Oil Refinery*,” Praxair, Inc., June 2010[10]

The National Renewable Energy Laboratory publication, *Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming*, NREL/TP-570-27637, February 2001.[11]

Perry & Chilton, Chemical Engineer’s Handbook, 5th Ed., c 1973

The National Energy Technology Laboratory guidance, “*Estimating Carbon Dioxide Transport and Storage Costs*,” DOE/NETL-400/2010/1447, March 2010.[12]

Al-Juaied, Mohammed A and Whitmore, Adam, “*Realistic Costs of Carbon Capture*” Discussion Paper 2009-08, Cambridge, Mass.: Belfer Center for Science and International Affairs, July 2009.[13]

Jeremy David and Howard Herzog, “*The Cost of Carbon Capture*,” Massachusetts Institute of Technology (MIT), Cambridge, MA, USA[14]

GHG Mitigation Strategies Database – The GHG Mitigation Strategies Database did not contain any information for emission sources presented in this analysis.[15]

Ordorica-Garcia, Wong, Faltinson, “*CO2 Supply from the Fort McMurray Area, 2005-2020*,” Alberta Research Council, Inc., 2009[16]

U.S. DOE, NETL, “*The Cost of Carbon Dioxide Capture and Storage in Geologic Formations*,” 2008[17]

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[10] http://www.osti.gov/bridge/servlets/purl/1014021-IesmBR/1014021.pdf

[11] http://www.nrel.gov/docs/fy01osti/27637.pdf

[12] http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&PubId=338

[13] http://belfercenter.ksg.harvard.edu/files/2009_AlJuaied_Whitmore_Realistic_Costs_of_Carbon_Capture_web.pdf

[14] http://www.netl.doe.gov/publications/proceedings/01/carbon_seq_wksp/david-herzog.pdf

[15] Previously located at http://ghg.ie.unc.edu:8080/GHGMDB/

[16] http://www.assembly.ab.ca/lao/library/egovdocs/2009/alrc/173912.pdf

[17] http://www.netl.doe.gov/publications/factsheets/program/Prog065.pdf

9.3 BACT TOP-DOWN APPROACH

9.3.1. STEP 1 - IDENTIFY CONTROL TECHNOLOGIES

Available control technologies with the practical potential for application to the emission unit and regulated air pollutant in question are identified. The selected control technologies vary widely depending on the process technology and pollutant being controlled. The application of demonstrated control technologies in other similar source categories to the emission unit in question may also be considered. While identified technologies may be eliminated in subsequent steps in the analysis, control technologies with potential application to the emission unit under review are identified in this step.

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

1. EPA's Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database;[18]
2. Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies;
3. Engineering experience with similar control applications;
4. Information provided by air pollution control equipment vendors with significant market share in the industry; and/or
5. Review of literature from industrial, technical, government, academic and trade organizations.

However, since GHG BACT is a new and evolving requirement, these tools and platforms are of limited use in preparing the GHG BACT. Outside of the power generation industry, there are very few examples of operational GHG control technologies specifically targeting control of GHGs. Therefore, to establish BACT for GHGs, Equistar will rely primarily on items (3) through (5) above, and the aforementioned references. Those include references from the EPA BACT GHG Workgroup.

9.3.2. STEP 2 - ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling the PSD-triggering pollutant emissions from the source in question. The first question in determining whether or not a technology is feasible is whether or not it is demonstrated. Whether or not a control technology is demonstrated is considered to be a relatively straightforward determination. Demonstrated has specific meaning in this regard. Demonstrated "means that it has been installed and operated successfully elsewhere on a similar facility." *Prairie State*, slip op. at 45. "This step should be straightforward for control technologies

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[18] http://cfpub.epa.gov/RBLC/

that are demonstrated--if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible."[19]

The US EPA Environmental Appeals Board (EAB) addressed how control technologies are considered in a BACT analysis in *In re Cardinal FG Co.*, 12 E.A.D. 153 (EAB 2005), upholding a permitting agency's decision that a technology was not demonstrated. The permitting authority, in the response to comments, concluded that although the technology was in use on other facilities in the industry, it was not widely adopted by facilities using the specific process planned for the proposed facility. The permitting authority explained the specific technical reasons why the technology would not work for the source in question and sufficiently distinguished the proposed facility from the other facilities that were using it.

One plant was distinguished on technical grounds, two other plants on grounds that the technology at issue resulted in higher emission limits than those specified for the proposed facility, and another plant on grounds that the two to three years' experience the plant had operating the technology was not sufficient to support that the technology was demonstrated. An argument that a technology would result in higher emissions by itself is not sufficient to exclude it at step 2. The issue of effectiveness of the technology should be dealt with in step 3, ranking of technologies. Because this comment was made in the response to comments, it appeared to be another reason to reject the technology, but not supportive of why the technology should be eliminated under step 2. As the EAB explained, even if a top-down step was not done exactly correctly, evidence that it would have made no difference in the BACT analysis is sufficient to justify not remanding the permit to redo that step.

An undemonstrated technology is only technically feasible if it is "available" and "applicable." A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available".[20] Control technologies in the R&D and pilot scale phases are not considered available. Based on EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source. Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative.

The NSR Manual explains the concept of applicability as follows: "An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration."[21] Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the NSR Manual.

> *Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a*

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

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

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

> *commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary.*
>
> *For process-type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which the process technique had been applied previously. Absent an explanation of unusual circumstances by the applicant showing why a particular process cannot be used on the proposed source the review authority may presume it is technically feasible.*[22]

The EAB has relied on the NSR Manual for its decisions regarding applicability.

It is important to note that emerging control technologies whose installations are primarily for research and development, or as demonstration projects for a particular process unit, do not represent technologies that are necessarily both available and applicable to all similar process units.

9.3.3. STEP 3 - RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

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

In this BACT analysis, there are instances in which Equistar has chosen to employ multiple technologies for control of GHG emissions. In those cases, relative ranking of the individual control effectiveness is irrelevant and has not been done. Such relative ranking would have no effect on the decision making required by the BACT analysis. As an alternative, where technologies have been combined, Equistar has provided a “grouped” effectiveness. An example is that use of a low carbon primary fuel and use of high hydrogen fuel gases can be evaluated individually or as a grouped technology described as fuels selection.

Collateral effects are usually not considered until step four of the five step top-down BACT analysis and could result in rejection of a favorable control option at step 3. As a result, top-down BACT does

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[22] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18-B.20.

not necessarily drive an integrated manufacturing site to lowest emissions of GHG, and particularly CO2. For example, a carbon dioxide capture system is a large energy user. That energy is most often supplied by a fossil fuel powered energy source. As a result that power source generates CO2, partially offsetting the amount captured. Equistar has identified several instances in which careful consideration of collateral effects are considered. Those instances are presented within this document to clearly indicate where the collateral effects have influenced the evaluation.

9.3.4. STEP 4 - EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

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

Please note that the GHG BACT assessment presents a unique challenge with respect to the evaluation of CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (e.g., flares and thermal oxidizers) actually convert CH_4 emissions to CO_2 emissions. Consequently, the reduction of one GHG (i.e., CH_4) results in a simultaneous increase in emissions of another GHG (i.e., CO_2).

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

According to 40 CFR §52.21(b)(49)(ii), CO_2e emissions must be calculated by scaling the mass of each of the six GHGs by the gas' associated global warming potential (GWP), which is established in Table A-1 to Subpart A of 40 CFR Part 98. Therefore, to determine the most appropriate strategy for prioritizing the control of CO_2 and CH_4 emissions, Equistar considered each component's relative GWP. As presented in Table 1, the GWP of CH_4 is 21 times the GWP of CO_2. Therefore, one ton of atmospheric CH_4 emissions has the same predicted global warming effect of 21 tons of CO_2e emissions. On the other hand, one ton of CH_4 that is combusted to form CO_2 emissions prior to atmospheric release equates to 2.7 tons of CO_2e emissions. Since the combustion of CH_4 decreases GHG emissions by approximately 87 percent on a CO_2e basis, combustion of CH_4 is preferential to direct emission of CH_4.

BACT Table 1 provides the Global Warming Potential (GWP) for the three greenhouse gases expected to be emitted by the methanol unit at Equistar's Channelview plant. The GWP is based on a 100-year time horizon. These data are taken from Table A-1 of 40 CFR Part 98.

BACT TABLE 1 GLOBAL WARMING POTENTIALS

Pollutant[1]	**GWP**[2]
CO_2	1
CH_4	21
N_2O	310

9.3.5. STEP 5 - SELECT BACT

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

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

NAAQS have not been established for GHGs and a dispersion modeling analysis for GHG emissions is not a required element of a PSD permit application for GHGs. Since localized short-term health and environmental effects from GHG emissions are not recognized, this BACT evaluation relies on technical feasibility, control effectiveness, and determinations of collateral impacts and costs.

9.4 REFORMER FURNACE – GHG BACT

Greenhouse Gas (GHG) Best Available Control Technology (BACT) for the reformer furnace has been evaluated via a "top-down" five-step approach. Each of those five steps is outlined below. The analysis has been conducted for each of the three GHGs emitted from the furnace stack. That analysis led to the conclusion that BACT for the reformer furnace GHG combustion emissions is fuels selection (CO2, CH4). In addition, energy efficient design (CO2, CH4 and N2O) and proper operational control (CO2, CH4) also limit GHG emissions.

9.4.1. REFORMER FURNACE – CO2 BACT

9.4.1.1 IDENTIFICATION OF POTENTIAL CO_2 CONTROL TECHNOLOGIES (STEP 1)

Step 1 Summary

Equistar used a combination of published resources and general knowledge of industry practices to generate a list of five potential controls for carbon dioxide resulting from the reformer furnace operation. All are presented in Step 1 of this BACT analysis.

9.4.1.1.1 POTENTIAL CO2 CONTROL TECHNOLOGIES

The following potential CO_2 control strategies for the reformer furnace were considered as part of this BACT analysis:

▲ Use hydrogen as the primary fuel for the reformer furnace.

Hydrogen when burned has no potential for generation of CO2 emissions.

▲ Carbon capture and storage (CCS)

CCS is a developing technology that captures CO2 and permanently stores the CO2 in lieu of it being emitted to the atmosphere.

▲ Fuels Selection

- Selection of the lowest carbon fuel as the primary fuel

Various fuels have differing potential for generation of CO2 through combustion. Hydrogen has none. Methane will generate CO2 through combustion; however ethane (C_2H_6) would produce more CO2 than methane for the same heat release from combustion.

- Use of plant produced fuel gas to fire the furnace

Equistar may use fuel gas containing hydrocarbons, primarily methane, and hydrogen, as a fuel for the furnace offsetting natural gas use.

▲ Installation of energy efficiency options on the reformer furnace

Fuel combustion in the furnace, which results in CO2 generation, results in heat energy release to the furnace firebox. A highly energy efficient furnace will transfer a greater fraction of the heat into the process stream, the intended consequence, than will an inefficient furnace. This results in less fuel needing to be combusted, and less CO2 generation for the same amount of process stream heating.

▲ Best Operational Practices

Best operational practices can be characterized as steps or actions taken by owners/operators of furnace to maintain energy efficiency.

No other control technologies for CO2 from the reformer furnace flue gas were identified.

9.4.1.2 ELIMINATE TECHNICALLY INFEASIBLE OPTIONS (STEP 2)

9.4.1.2.1 STEP 2 SUMMARY

In the evaluation of technical feasibility presented below, of the five listed control options, all but CCS are believed to be technically feasible for control of CO_2 emissions associated with the operation of the reformer furnace. However, all five CO_2 control technologies, including CCS, are progressed to Step 3.

CCS technologies continue to develop, with several large scale demonstration projects underway at this time that may be relevant. The component elements of CCS (capture, transportation and storage) have all been demonstrated in various projects. However, Equistar has been unable to identify any reformer furnace fitted with both selective catalytic reduction and flue gas carbon capture. The determination of technical feasibility of CCS at this point for Equistar's project is largely subjective. Therefore Equistar has chosen to progress all five technologies, including CCS, to Step 3 in this five-step top-down BACT analysis without a determination that CCS is technically feasible or infeasible. More detailed discussion is provided below.

9.4.1.2.2 USE OF HYDROGEN AS PRIMARY FUEL FOR THE REFORMER

During combustion, hydrogen generates no CO_2. Hydrogen could be used as a fuel for the reformer furnace provided that engineering and operational difficulties, such as flash back at the burner, flame stability, and radiant heat distribution in the firebox could be overcome. Hydrogen use as the primary fuel is progressed to Step 3 of this analysis.

9.4.1.2.3 CARBON CAPTURE AND STORAGE

Carbon capture and storage (CCS) involves separation and capture of CO_2 emissions from the flue gas prior to being emitted from the stack, compression of the captured CO_2, transportation of the compressed CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. For CCS to be technically feasible, all three components needed for CCS must be technically feasible; carbon capture and compression, transport, and storage. Equistar has determined that CCS could be rejected at this stage in this top-down BACT analysis due to technical infeasibility. The current stage of development of the related technologies falls short of having CCS being "demonstrated" for control of CO_2 from a large reformer furnace's flue gas where SCR is employed as a control for NOx. Because CCS as a control technology for CO_2 from the reformer flue gas is eliminated in Step 4 of this analysis, a detailed engineering evaluation of the technical feasibility of CCS has not been conducted. Although CCS is progressed to step 3 of this analysis, Equistar offers the following discussion of the feasibility aspects of CCS for this project.

The recently issued U.S. EPA guidance for PSD and Title V Permitting of Greenhouse Gases states:

> " *For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for facilities emitting* CO_2 *in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity* CO_2 *streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and*

> *iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs."*[23]

It must be noted that the "industrial facilities with high-purity CO2 stream" identified in the guidance document make reference to process streams and process vent streams that contain substantially higher CO2 concentrations than Reformer furnace flue gas. None of those "high-purity CO2 streams" mentioned in this reference is generated from simple combustion of a fossil fuel. The flue gas produced by Equistar's reformer will contain a low concentration of CO_2, about 4% at the lower end of the predicted range, and therefore CCS may not qualify as an "available" add-on control technology for this flue gas stream. Many combustion streams discussed in literature, most associated with coal fired power plant, have CO2 concentrations of 10% or higher, making CO2 removal much more effective. This is especially true for the coal fired power plants with the combustion of large quantities of fuel, providing substantial economies of scale. Based on this EPA guidance, it may not have been necessary to list CCS as a potential control option in Step 1 of this BACT analysis.

Currently only two options appear to be feasible for capture of CO2 from the reformer flue gas: Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes. In one 2009 M.I.T. study conducted for the Clean Air Task Force, it was noted that "To date, all commercial post-combustion CO2 capture plants use chemical absorption processes with monoethanolamine (MEA)-based solvents."[24] Although absorption technologies are currently available that may be adaptable to flue gas streams of similar character to the reformer furnace flue gas, to Equistar's knowledge the technology has never been commercially demonstrated for flue gas control in large scale industrial reformer furnace operation where the reformer furnace is equipped with selective catalytic reduction (SCR) controls for NOx.

Various white papers for GHG reduction options were reviewed for the discussion of CCS BACT. In the GHG BACT Guidance for Boilers white paper, a brief overview of the CCS process is provided and the guidance cites the Interagency Task Force on Carbon Capture and Storage for the current development status of CCS technologies.[25,26] In the Interagency Task Force report on CCS technologies, a number of pre- and post-combustion CCS projects are discussed in detail; however, many of these projects are in formative stages of development and are predominantly power plant demonstration projects (and mainly slip stream projects). Capture-only technologies are technically available; however not yet commercially demonstrated for low CO2 concentration flue gas streams where SCR is installed for NOx control.

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

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[23] US EPA, Office of Air Quality Planning and Standards, "PSD and Title V Permitting Guidance for Greenhouse Gases", March 2011, p. 32.

[24] Herzog, Meldon, Hatton, Advanced Post-Combustion CO2 Capture, April 2009, p 7, http://web.mit.edu/mitei/docs/reports/herzog-meldon-hatton.pdf

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

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

- Leucadia Energy: a methanol plant in Louisiana where 4 million tonnes per year of CO_2 will be captured and used in an enhanced oil recovery (EOR) application.
- Archer Daniels Midland: an ethanol plant in Illinois where 900,000 tonnes per year of CO_2 will be captured and stored in a saline formation directly below the plant site.
- Air Products: a hydrogen-production facility in Texas where 900,000 tonnes per year of CO_2 will be captured and used in an EOR application.

At present, these industrial deployments were selected for funding by DOE in June 2010 and are moving into construction/demonstration phases. Therefore, they are not yet demonstrated. More importantly, each of these three projects is capturing CO2 from a process stream as opposed to a flue gas stream. Therefore these projects cannot be used to represent a control technology available for Equistar's reformer furnace flue gas. They would remain irrelevant to this BACT analysis even if in operation.

Another, sometimes unrecognized demand associated with CCS is the greatly increased water use. At a time when availability of water resources along the Texas Gulf Coast is in question, any substantial increase in water withdrawal and consumption must be evaluated. An amine based collection system for this reformer furnace would require large amounts cooling water as part of the amine regeneration stage. After the CO2 has been captured, it must be compressed to approximately 2,000 psig for transport. That compression introduces an additional significant demand for cooling water to remove the heat of compression. There are alternatives that would reduce or eliminate the need for cooling water; however the alternate methods, such as finned exchangers with fan induced air flow for cooling, are relatively inefficient and create a collateral demand for electrical power and the associated generation of additional CO2.

The next step in CCS is the transport of the captured and compressed CO2 to a suitable location for storage. This would typically be via pipeline, and that would be most suitable for the Equistar methanol unit CO2 if it were captured. Pipeline transport is an available and demonstrated, although costly, technology.

Capture of the CO_2 stream and transport are not sufficient control technologies by themselves, but require the additional step of permanent storage. After separation and transport, storage could involve sequestering the CO_2 through various means such as enhanced oil recovery, injection into saline aquifers, and sequestration in un-minable coal seams, each of which are discussed below:

- *Enhanced Oil Recovery (EOR)*:

EOR involves injecting CO_2 into a depleted oil field underground, which increases the reservoir pressure, dissolves the CO_2 in the crude oil (thus reducing its viscosity) and enables the oil to flow more freely through the formation with the decreased viscosity and increased pressure. A portion of the injected CO_2 would flow to the surface with the oil and be captured, separated, and then re-injected. At the end of EOR, the CO_2 would be stored in the depleted oil field.

- *Saline Aquifers*:

Deep saline aquifers have the potential to store post-capture CO2 deep underground below impermeable cap rock.

- *Un-Mineable Coal Seams*:

Additional storage is possible by injecting the CO_2 into un-mineable coal seams. This has been used successfully to recover coal bed methane. Recovering methane is enhanced by injecting CO_2 or nitrogen into the coal bed, which adsorbs onto the coal surface thereby releases methane.

There are additional methods of sequestration such as potential direct ocean injection of CO_2 and algae capture and sequestration (and subsequent conversion to fuel); however, these methods are not as widely documented in the literature for industrial scale applications. As such, while capture-only technologies may be technologically available at a small-scale, the limiting factor is the availability of a mechanism for the facility to permanently store the captured CO_2.

To Equistar's knowledge, the Channelview facility is not located near a demonstrated permanent CO_2 storage option with a proven history of long term CO_2 storage. However, the facility is located near numerous potential storage locations.

The Channelview facility is located approximately 30 miles from the Denbury Green Pipeline which will provide CO_2 for EOR operations in the Hasting oil field in Brazoria County, TX. Denbury Resources is actively injecting CO_2 for EOR in the Oyster Bayou Field in east Chambers County, Texas, and in the Hastings Oil Field in Brazoria County, TX. This option is the clear, lowest cost storage choice for the CO_2 that would be captured and transported from Equistar's methanol unit. Also, the Frio Saline Aquifer underlies this part of the Texas Gulf Coast and could serve as storage for captured and compressed CO_2. Finally, there are a number of salt domes around the Houston, TX area into which solution mining could create caverns for CO_2 storage. Equistar is not aware of any un-mineable coal seams along the Texas Gulf coast suitable for CO_2 storage. Each of the potential options has risks. Examples are provided below.

An evaluation of the Hastings field was conducted as part of a CCS demonstration project that was subsequently abandoned. That evaluation includes portions addressing risks of failures that could only be further evaluated as part of a demonstration project. The project was led by Praxair, Inc., with other project participants: BP Products North America Inc., Denbury Onshore, LLC (Denbury), and Gulf Coast Carbon Center (GCCC) at the Bureau of Economic Geology of The University of Texas at Austin. In a project update document titled "*Carbon Capture and Sequestration (via Enhanced Oil Recovery) from a Hydrogen Production Facility in an Oil Refinery*," risk factors were described, including uncertainty of the upward transmission of injected CO_2. Although the excerpt below was taken from a section of the report relating to monitoring, verification and accounting (MVA), it speaks to routes of upward migration of injected CO_2, and the methods for detection of that migration.[27] The MVA aspect is an essential element of a well-run EOR project. The lengthy excerpt below shows that there are various alternatives to detect upward migration of CO_2, and that there were risk mitigation plans for upward migration that might be detected. Nevertheless, the identified risks raise concern regarding the viability of EOR in the Hasting Field.

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[27] Carbon Capture and Sequestration (via Enhanced Oil Recovery) from a Hydrogen Production Facility in an Oil Refinery , Appendix D, Page D-21, http://www.osti.gov/bridge/servlets/purl/1014021-IesmBR/1014021.pdf

The research MVA program will focus on areas of uncertainty in retention of fluids in the injection zone. As these oil fields have retained oil and gas for geologic time, we consider that it is documented the natural seal is adequate to support a significant CO_2 *column with migration occurring possibly only at diffusion rates. Risk assessment and experience indicates that the most probable migration paths are (1) non-sealing well completions; (2) vertical migration up fault when reservoir pressure exceeds original pressure (3) off-structure or out of compartment migration of* CO_2 *or brine as a result of elevated pressure into areas not controlled as part of the flood. An MVA program is outlined for each of these risk areas and is linked to a mitigation or management process that can be implemented to result in adequate assurance that the* CO_2 *injected is permanently stored.*

Non sealing well completions

Wells that penetrate the seal are potential weak points, especially during injection. This occurs because older wells have been completed under older regulatory schemes. Wells that perform adequately during extraction, when they are pressure sinks, have the possibility of becoming upwardly transmissive during injection when pressure of the reservoir is increased. Wells that are actively producing can be inspected via a logging program, however wells that have been plugged and abandoned (P&A) are prohibitively expensive to reenter to inspect and therefore do not provide viable candidates for monitoring. The research MVA program is intended to extend the commercial operations well integrity program, and test the effectiveness of the commercial operations program. Activities that will be considered for possible inclusion in the research MVA proposal:

(1) Additional logging program (e.g. temperature, radioactive tracers, high end wireline tools)
(2) Above zone pressure monitoring – ambient and introduced fluids
(3) Well deconstruction – possibly associated with workover.
(4) Soil gas, groundwater, or other near-surface monitoring.

In Hastings, water disposal into the Miocene overlying the Frio CO_2 *injection zone has elevated pressure and perturbed geochemistry. In the short term, this elevated pressure provides a barrier to upward flow. It will be interesting to assess how long this pressure barrier will be sustained with respect to long term storage goals. (it should be noted that we are making efforts to restrict or eliminate Miocene water injection as it is creating several adverse problems in the field re-development, will be interesting to monitor how quickly the Miocene "bleeds" off if any with time once injection has been curtailed). It may add difficulties to above-zone detection methods.*

Possible methods for looking for flawed wellbore migration are: Thermal anomalies (hot fluids expelled from depth, or cold areas in shallow zones where CO_2 *flashes to gas). Can be done though casing*
Noise anomalies - Can be done though casing
Pressure anomalies - requires perforations

Geochemical anomalies - requires perforations.
Soil gas methods near surface (methane, CO_2)
Augmented soil gas/aquifer surveillance methods (noble gases/isotopes,tracers)

Vertical Migration up faults

Faults related to salt structure are ubiquitous in the Gulf coast. Some faults are clearly vertically transmissive; others trap thick oil and gas columns and are therefore not transmissive at rates relevant to CO_2 storage. It is sometimes not clear how faults will perform when pressure is increased, and this uncertainty can be a block to use/storage of anthropogenic CO_2 in faulted settings. Technique development is needed to determine effective methods to document that faults are sealed to vertical flow. Hastings has a main growth fault that extends to surface as well as several cross faults. Production history suggest that cross faults maybe somewhat cross-fault transmissive, however the vertical performance has not been assessed.

Activities that will be considered for possible inclusion in the proposal:
(1) Natural fault performance - any near surface soil gas anomalies - methane , noble gasses
(2) Soil gas, groundwater, or other near-surface monitoring, same as above but focused on fault. Location - where master fault approaches surface.
(3) Logging program for wells that cut the fault (e.g. temperature, radioactive tracers, high end wireline tools) looking for changes (need before and after injection in wells that cut faults as CO_2 is injected).
(4) Above zone pressure and geochemical monitoring - any changes as CO_2 is introduced? may be impossible with water disposal in Miocene. Need to perforate one or more wells where they cut fault. Sample for PFT.
(5) Geophysical methods – design VSP or cross well acoustic array to look for changes along fault plane. Consider passive acoustic methods to determine if there is any viability in ductile rocks in Gulf Coast. Consider gravity methods.

For the CO_2 that will be generated by the Equistar Channelview reformer furnace, storage may not be technically feasible even by the most reasonable method, EOR in the Hastings Field. While DOE funded demonstration projects will rely on the Hastings field for storage/sequestration, those demonstration projects are still in early stages. The MVA work done in association with those demonstration projects will add to understanding and quantification of risks of EOR in the Hastings Field. Until that time it would be unreasonable for Equistar to commit to storage of CO_2 in the Hastings Field in association with this project where the entire cost of the project is provided by Equistar. EOR activities are being successfully carried out in west Texas; however the distance for pipeline transmission to the area may make this option impractical.

The Report of the Interagency Task Force on Carbon Capture and Storage includes Appendix H, Potential Causes of Long-Term Storage Risk and/or Liability. This list of eight risk areas are also cause for concern with any storage option and must be weighed in any decision for CO_2 storage. Those risks stated in verbatim from the Report include:

1. **Scientifically understood phenomena**. For example, migration of CO2 in scientifically understood ways as a result of high injection pressures.
2. **Scientific uncertainties or unknown phenomena** that would alter previous understandings about risks.
3. **Operator error.** For example, an operator misapplies monitoring technology and fails to detect migration of CO2, or an operator misuses injection equipment, which fails, and CO2 is released from the storage site.
4. **Regulatory mistake or oversight**. For example, a State or Federal agency reviewing a permit application fails to detect a geological feature, or fails to identify migration of CO2 in monitoring data.
5. **Falsification and illegal conduct**. For examples, a site operator falsifies geological data in order to obtain a permit; a site operator falsifies monitoring data in order to avoid the costs of remediation; or a site operator stores more CO2 than allowed under a permit to obtain the associated income stream.
6. **Policy changes**. For example, a subsequent Administration withdraws funding for CCS activities, or the relevant legal framework changes, or a State ceases funding for a storage site.
7. **Acts of God**. For example, an earthquake causes a release from a storage site.
8. **Judicial system error**. For example, groundwater contamination develops near a storage site. The harm is not in fact caused by the site, but would have occurred even without the storage activity. A court nevertheless erroneously holds the site operator liable, for example on an ultrahazardous activity theory.

The Frio Saline Aquifer has been the subject of sequestration modeling and actual field tests. One test was documented In a 2005 report by the Gulf Coast Carbon Center titled "*Gas-Water-Rock Interactions in Saline Aquifers Following CO2 Injection: Results from Frio Formation, Texas, USA*"[28]. In that report, representatives from the U.S. Geological Survey, Oak Ridge National Laboratory and the Alberta Research Council made the following observations:

> *To investigate the potential for the geologic storage of CO_2 in saline sedimentary aquifers, ~16 million kg of CO_2 were injected at ~1,500-m depth into a 24-m sandstone section of the Frio Formation—a regional brine and oil reservoir in the U. S. Gulf Coast. Fluid samples obtained from the injection and observation wells before, during and post CO_2 injection, show a Na-Ca-Cl type brine with 93,000 mg/L TDS and near saturation of CH_4 at reservoir conditions. As injected CO_2 became the dominant gas at the observation well, results showed sharp drops in pH (6.5 to 5.7), pronounced increases in alkalinity (100 to 3,000 mg/L as HCO_3) and Fe (30 to 1,100 mg/L), and significant shifts in the isotopic compositions of H_2O, DIC and CH_4. Geochemical modeling indicates that brine pH would have dropped lower, but for the buffering by dissolution of carbonate and iron oxyhydroxides. The low pH values resulting from CO_2 injection could cause rapid dissolution of carbonate and other minerals creating pathways for CO_2 and brine leakage. Dissolution of some minerals, especially iron oxyhydroxides could mobilize trace metals and other toxic components. Also, where residual oil and other organics are*

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[28] http://www.beg.utexas.edu/gccc/forum/codexdownloadpdf.php?ID=24

> *present, the injected CO_2 may mobilize organic compounds, some may be environmentally toxic. The $\delta^{18}O$ values for brine and CO2 samples indicate that supercritical CO_2 comprises ~45% of fluid volume in Frio sandstone near injection well ~6 months after end of injection. Post-injection sampling, coupled with geochemical modeling, indicate the brine gradually returning to its pre-injection composition.*

The injection of the CO_2 caused dissolution of surrounding formations, presenting additional risks which the authors summarized as follow:

> *The low pH values resulting from CO_2 injection could have important environmental implications:*
> *a) Dissolution of minerals, esp. iron oxyhdroxidescould mobilize toxic components;*
> *b) Dissolution of minerals may create pathways for CO_2 and brine leakage.*

Equistar owns and operates salt dome caverns for storage of hydrocarbons at Markham, TX and at Mont Belvieu, TX. Equistar believes these are effective and safe methods for terminalling light hydrocarbons. Similar storage of CO_2 may be a viable option; however a thorough technical evaluation has not been conducted.

Based on the aforementioned technical challenges with capture and storage of CO_2, CCS could be determined to be technically infeasible as BACT for reducing CO_2 emissions from Equistar's reformer furnace flue gas. An acceptance of CCS as GHG BACT for this process would come with significant technical risks. Accordingly, CCS should be eliminated as a potential control option in this BACT assessment for CO_2 emissions due to technical infeasibility. Nevertheless, discussion of CCS as an option for control is carried forward from this step of the top-down BACT analysis. As mentioned previously, that progression in this analysis should not be considered Equistar's acceptance that CCS is technically feasible, but rather recognition that the prohibitive costs can be more easily presented in Step 4 of this BACT analysis than to disprove the somewhat subjective aspects of *demonstrated, available and applicable*.

9.4.1.2.4 FUELS SELECTION

Equistar Channelview is a large chemical manufacturing complex with access to natural gas and plant produced fuel gases. The selection of which fuels to use for firing the furnace has a direct impact on CO_2 emissions and is progressed to Step 3 of this BACT analysis. Fuels selection has two component parts; selection of lowest carbon fuel and use of plant produced fuel gas to fire the furnace.

Selection of the Lowest Carbon Fuel

For GHG BACT analyses, low-carbon intensity (mass of carbon per MMBtu) fuel selection is a control option that can be considered a lower emitting process. The reformer furnace will be fired with natural gas and low carbon fuel gases as the primary fuels.

Use of plant produced fuel gas to fire the furnace

Complex petrochemical manufacturing plants may produce gas streams that are suitable for introduction to a fuel gas system with the only other reasonable option being flaring. These gases include primarily methane and hydrogen. Combustion of these streams may further reduce CO_2 emissions.

9.4.1.2.5 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE REFORMER FURNACE

The manufacture of methanol in a methane reformer begins with production of synthesis gas in the reformer furnace. This step is energy intensive, and produces more than 99% of the CO_2 emissions associated with this project. During normal operation, the furnace design targets about 91% efficiency. Thus, this energy efficient technology is feasible and is progressed to Step 3 of this analysis.

9.4.1.2.6 BEST OPERATIONAL PRACTICES

Best Operational Practices include periodic furnace tune-up and oxygen trim control. These practices are technically feasible and have been demonstrated. Best Operational Practices are progressed to Step 3 of this BACT analysis where they are discussed in more detail.

9.4.1.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

9.4.1.3.1 SUMMARY OF STEP 3

Of the five control technologies that passed through Step 2, it is determined in Step 3 that use of hydrogen to fuel the furnace would be 100% effective in reducing CO_2 emissions. CCS would be the next most effective control of CO_2 emissions at 90% control without consideration for impacts on other sources, but would provide about 57% control if increases elsewhere are considered. That is followed by fuel selection at a minimum of 12% effectiveness. Energy efficiency has been incorporated into the existing design, as industry standard practice. Because the efficiency of the existing reformer is not differential with respect to industry, 0% control effectiveness is assigned. Adoption of best operational practices also is progressed as a CO_2 limiting technology, although these practices also have 0% effectiveness assigned. The options are presented in order of decreasing effectiveness in BACT Table 2 below.

BACT Table 2: Furnace CO_2 Control Effectiveness

Technology	Effectiveness	CO_2 Emission w/ Control, TPY
Use of hydrogen as primary fuel	100%	0
Carbon Capture and Storage	90% (57%)	82,660 w/ 90% Control
Fuels Selection**	>12%	826,600
Energy Efficiency**	0%	826,600

Best Operational Practices**	0%	826,600

* Control effectiveness is reduced to approximately 57% if collateral impacts are considered as described in Step 4.

** Assumes all three technologies are employed; fuels selection, energy efficiency and best operational practices.

9.4.1.3.2 USE OF HYDROGEN AS PRIMARY FUEL

Hydrogen has no capacity to produce CO_2 when combusted. Provided that engineering and operational difficulties, such as flash back at the burner, flame stability, and radiant heat distribution in the firebox could be overcome, hydrogen would provide 100% effectiveness in control of CO_2 emissions from the reformer furnace. This option is progressed to Step 4 where it is rejected on the basis of collateral effects.

CO_2 emissions with hydrogen as primary fuel = 0 tons/year.

9.4.1.3.3 CARBON CAPTURE AND STORAGE

Almost universally, references cite CO_2 capture efficiencies for post-combustion control at 90%, including the study by Jeremy David and Howard Herzog, "*The Cost of Carbon Capture*," Massachusetts Institute of Technology (MIT), Cambridge, MA, USA in which the authors reviewed several projects.[29] For purposes of this analysis the capture efficiency is irrelevant because CCS is being considered the second most effective control measure with an assumed 90% control effectiveness.

With an uncontrolled emission estimate of 826,600 TPY CO_2, the application of a 90% control would result in emissions originating from the reformer furnace of 82,660 TPY CO_2. However, the generation of power to operate the carbon capture equipment and to compress the CO_2 prior to transport is significant. With consideration of that contribution of CO_2 elsewhere, the control effectiveness is estimated to be less than 57%.

An adjustment to overall efficiency must be applied due to the collateral emissions increases. A term called "CO_2 Avoided" is often used when a source must produce energy to drive collection and compression equipment, thus reducing capacity to export power or increasing demand for overall power production so that the collection and compression equipment may be operated. In either case, the net effect is that more fossil fuel is combusted, generating more CO_2 prior to control. Where that CO_2 is generated by the very unit generating the power that is used by the capture and compression equipment, the created CO_2 for extra power generation is also captured by the collection and compression system. Where the power to operate a CO_2 collection and compression system, as would be the case for an Equistar installation, it cannot be assumed that the power generating facility is equipped with CO_2 controls.

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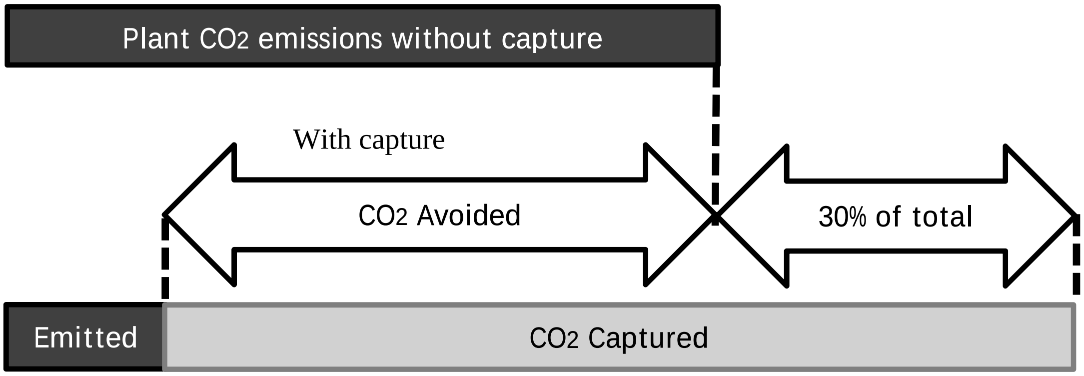
[29] http://www.netl.doe.gov/publications/proceedings/01/carbon_seq_wksp/david-herzog.pdf

The classic example of "CO_2 avoided" compares a plant with and without CO_2 capture and compression, showing that the CO_2 avoided is the difference between CO_2 emissions without capture and emissions with capture, but also showing the increased overall CO_2 emissions due to extra power generation. It has been estimated that power plants would experience up to a 30 percent penalty in power generation, meaning that 30% of the plant's output goes to powering the carbon capture and compression facilities.[30] BACT Figure 1 shows graphically how this is manifested at a power plant.

BACT Figure 1: Power Plant CO_2 Emissions versus CO_2 Avoided with Control



For an installation such as Equistar's, in which it is assumed that the external power needed to operate the CO_2 capture and compression systems is generated by a source without CCS, the graphical example in BACT Figure 2 is more complex. As a result, for essentially the same overall cost, the amount of CO_2 captured is appreciably lower. That translates into a lower effectiveness when an overall GHG emissions potential is considered.

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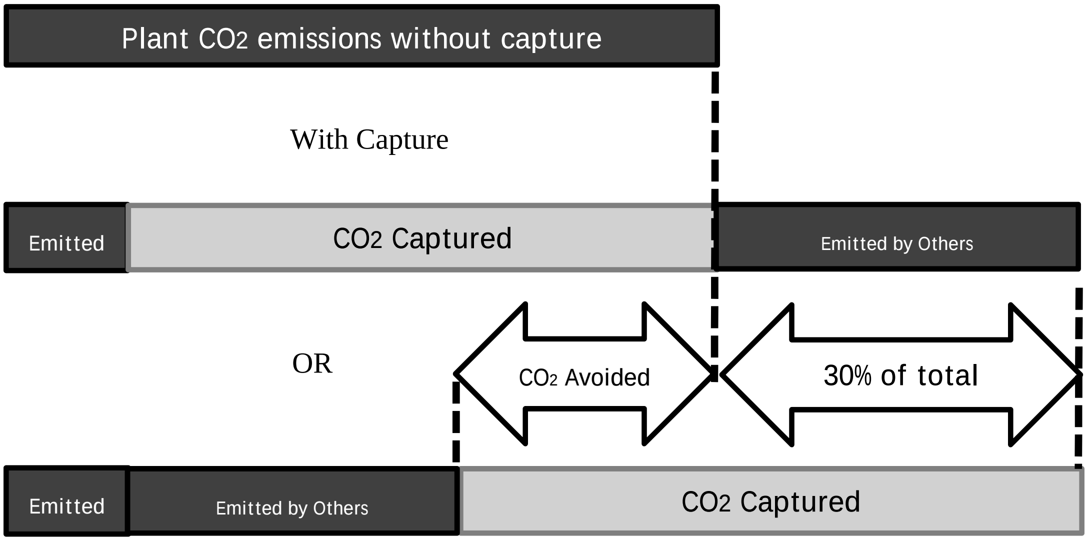
[30] Report of the Interagency Task Force on Carbon Capture and Storage, August 2010, Executive Summary, p 30.

BACT Figure 2: CO_2 Control with Power Generation by Others



Equistar's uncontrolled CO_2 emissions from the Reformer furnace flue are estimated to be approximately 826,600 tons per year. To avoid over-adjustment in the effectiveness, Equistar is assuming that the generation of energy by others accounts for only 25% of overall pre-control CO_2 emissions, as opposed to the average 30% presented by the Interagency Task Force on Carbon Capture and Storage.

Explanation 826,600 tons per year CO_2 uncontrolled

743,940 tons per year captured w/90% control
82,660 tons per year emitted directly w/ 90% control.

275,533 tons per year emitted by others to produce power for capture and control: 275,533/(275,533 + 826,600) = 0.25 or 25%

90% control at furnace = (743,940/826,600)
57% control considering emissions by others =(743,940 – 275,533)/826,600

9.4.1.3.4 FUELS SELECTION

Fuels selection is presented in two parts, selection of the primary low carbon fuel and use of plant fuel gas, including hydrogen streams. The careful selection of fuels will limit CO_2 generation from the furnace and from the site as a whole due to collateral effects.

9.4.1.3.4.1 Selection of the Lowest Carbon Fuel

Natural gas is the lowest emitting GHG fuel on a direct carbon basis of all typical fossil fuels. The CO_2 generating potential from methane is 12% lower than ethane, the next lowest CO_2

producing alkane. Thus, selection of CH_4 as the primary fuel, as opposed to another fossil fuel, has a minimum of 12% $(1-{}^{1}/_{1.14})$ control effectiveness.

Use of natural gas as the primary furnace fuel to limit of CO_2 emissions is technically feasible. Natural gas is the lowest emitting carbon fuel that could be relied upon for continuous fueling of the proposed operation. The next higher MW common carbon based fuel is ethane whose CO_2 emitting potential is 14% higher than that of methane on a carbon to heating value basis. The impact of carbon based fuel selection on CO_2 emissions is significant. BACT Table 3 shows the relative CO_2 emissions to heat release capacity for several compounds, including common fuels.

BACT Table 3: Carbon dioxide production related to fuel heating values.

Fuel	Btu/lb (HHV)	Lb CO_2/lb fuel	Lb CO_2/MMBtu *	Lb CO_2/MMBtu v. CH_4
Methane	23,861	2.75	115	1.00
Ethylene	21,625	3.14	145	1.26
Ethane	22,304	2.93	131	1.14
Propylene	21,032	3.14	149	1.30
Propane	21,646	3.00	139	1.21
Butylene	20,833	3.14	151	1.31
Butane	21,293	3.03	142	1.23

* Assuming complete combustion to form CO_2.

Combustion of natural gas, primarily methane, is technically feasible and effective for limiting emissions of CO_2.

Based on natural gas firing of the furnace, the emissions from the reformer furnace are estimated to be 826,600 TPY CO_2. This includes concurrent incorporation of energy efficient design and adoption of best operational practices.

9.4.1.3.4.2 Use of plant produced fuel gas to fire the furnace

As stated previously, complex chemical plants produce gas streams that are suitable for introduction to a fuel gas system. The gases are primarily methane and hydrogen, along with occasional small quantities of other hydrocarbons. If flared as opposed to being used as fuel, essentially all carbon content of the fuel gas would be converted to CO_2 with no beneficial use of the heating value of the flared gases. The consumption of fuels heavier than methane will produce more furnace flue gas CO_2 emissions than would methane firing alone. However those emissions would be offset pound-per-pound by the elimination of those CO_2 emissions at the flare. The net result is a reduction in site CO_2 emissions, because the burning of the fuel gas in the furnace offsets an equal amount (heating value basis) of methane burning. The unit may combust H_2 rich fuel gas as a secondary fuel when practicable and when available. The process produces H_2 that may enter the commercial H_2 market, offsetting on-purpose production of hydrogen by others which produces GHG emissions. If, for any reason, a portion of the produced

> hydrogen is not exported from the unit as a product, it may be used as a fuel to capture its heating value, thus offsetting some of the heat input that would otherwise come from natural gas or plant fuel gas. As a result the use of high H_2 fuel gas, which has no potential for generation of CO2 emissions, would further reduce the CO_2 emissions from this combustion source. Equistar views the hydrogen as a product and as a fuel gas component, and will select dispositions for any part of the produced hydrogen as business needs dictate.

Based on the above considerations for fuel selection, Equistar proposes to (1) use natural gas as the primary fuel, and (2) use fuel gas containing hydrogen and/or hydrocarbons to the extent practicable and aligned with business needs. As compared to alternatives, the overall effectiveness in reducing or minimizing CO2 emissions is estimated at 12% minimum. The minimum is set by combustion of natural gas alone with no further consideration of the reductions provided by use of fuel gases, including high hydrogen content fuel gases.

Based on natural gas firing of the furnace, the emissions from the reformer furnace are estimated to be 826,600 TPY CO2. This includes incorporation of energy efficient design and adoption of best operational practices.

9.4.1.3.5 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE REFORMER FURNACE

The first step in the production of methanol in the unit is the production of synthesis gas in the methane reformer. The production of synthesis gas is energy intensive, and is the only significant source of GHG emissions in this unit. This section describes the energy efficiencies incorporated in the design of Equistar's Reformer furnace. This information is provided to demonstrate that the high efficiency is a critical design element of a reformer furnace and Equistar believes the furnace design and thermal efficiency target is comparable to the designs being used by others. The Equistar project is the restart of an existing methanol unit. While this existing furnace may not be as energy efficient as the most thermally efficient new furnace recently constructed within industry, as described below, Equistar does not believe this existing furnace to be significantly less efficient than the newest furnaces. The target efficiency is targeted to be 91%, meaning that only 9% of the energy released through combustion is lost in the flue gas. This leaves little opportunity for additional energy improvements. As reported in a 2008 EPA Energy Star publication[31] related to the petrochemical industry:

> *Approximately 30% of the fuel used in the chemical industry is used in fired heaters. The average thermal efficiency of furnace is estimated at 75-90% (Petrick and Pellegrino, 1999). Accounting for unavoidable heat losses and dewpoint considerations the theoretical maximum efficiency is around 92% (HHV) (Petrick and Pellegrino, 1999).*

Equistar's furnace is projected to have an energy efficiency of about 91%, close to the 92% theoretical maximum cited above. The same EnergyStar® document described several energy saving features, some of which are listed later in this discussion. Efficiencies described within the Energy

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[31] Neelis, Worrell, Masanet, *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry, An ENERGY STAR ® Guide for Energy and Plant Managers*, June 2008, p.57 http://www.energystar.gov/ia/business/industry/Petrochemical_Industry.pdf

Star® publication refer to some specific features to be incorporated into Equistar's reformer furnace include, but are not limited to those listed in BACT Table 4.

BACT Table 4: CO_2 Control Effectiveness for Energy Efficiency Aspects

Design Feature	Cited Effectiveness
Air to fuel ratio control	5% – 25%
Heat containment (refractory & Insulation)	2% – 5%
Sealing openings	5%
Flue gas heat recovery	8% - 18%

For somewhat of an apples and oranges comparison of reformer furnace efficiencies (89% to 95%) with other combustion sources. one can reference these excerpts from the Council of Industrial Boiler Owners publication, *Energy Efficiency and Industrial Boiler Efficiency, An Industry Perspective*, March 2003.[32]

Table 1: Typical Efficiencies for New boilers [page 5]

Coal fired boilers	75-85%
Oil fired boilers	72-50%
Gas fired boilers	70-75%

Typical Electric Generation Facilities [page 6]

Gas Turbines	25 – 38%
Coal Boilers/Steam Turbines	25-40%
Gas Turbines/HRSG Steam Turbines	40-51%

It is important to note that further steps to increase efficiency and simultaneously decrease flue gas temperature by recovery of more heat in the furnace convection section could create a problem of condensation and associated corrosion on the convection section tubes and in the stack.

The first step to convert a carbon-containing raw material such as natural gas into a mixture of H_2, CO and CO_2 called *Synthesis Gas* is by a catalytic process called *reforming*. Assured availability, optimum energy consumption, and environmental aspects are key considerations in the selection of the carbon-containing raw material. Natural gas is generally the preferred feedstock in the large-scale production of synthesis gas for methanol synthesis.

In steam reforming, the feedstock is catalytically reacted at a high temperature, in the absence of oxygen with the addition of water and possibly carbon dioxide. The reaction heat required is supplied externally, in this case by locating the catalyst filled process tubes inside of a hot furnace. In this reformer, natural gas is catalytically reacted in the presence of steam: The degree of conversion of methane increases with increasing temperature, increasing partial pressure of steam, and decreasing absolute pressure.

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[32] http://cibo.org/pubs/whitepaper1.pdf

The reaction process is highly endothermic, and heat must be input to the process to convert the natural gas to form the synthesis gas. The reaction takes place inside process tubes, commonly referred to as radiant tubes, where radiant heat is provided for the reaction process by burners which heat the tubes in the radiant section of the furnace.

The firebox is vertical with the radiant tubes supported vertically in the firebox, with burners firing down from the roof of the firebox. This allows radiant heat to be transferred uniformly, which minimizes localized coke build-up inside the radiant tubes, reduces spots of overheating which reduce efficiency, and helps maintain high energy efficiency of radiant heat transfer.

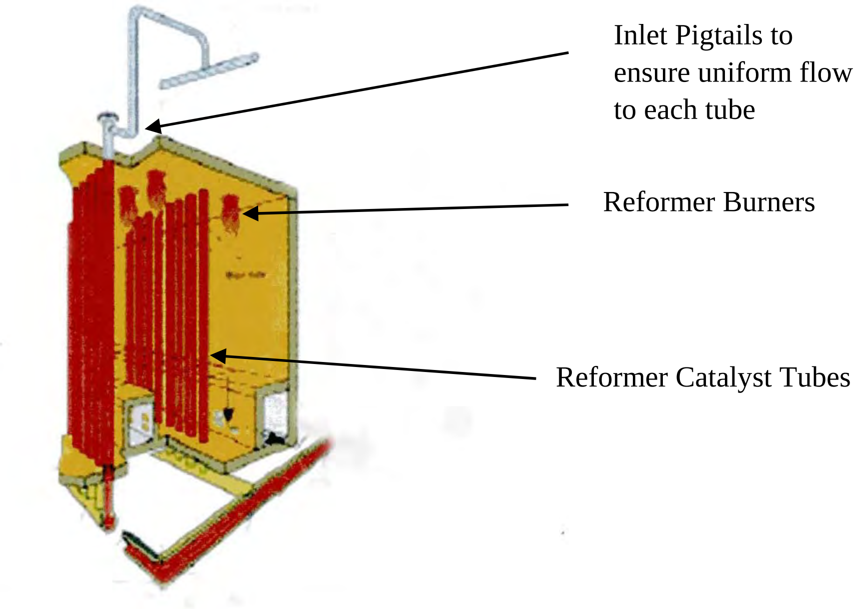
Reformer furnaces are known for extremely high operating temperatures. The temperature in a reformer furnace firebox will be on the order of 2100°F or higher. The higher the temperature of an object, the higher the radiant energy release of that object. Due to the high temperature in the firebox, the overwhelming majority of the heat transfer to the process tubes is through radiant heat transfer, as opposed to conductive or convective heat transfer. The hot firebox radiates heat to the relatively cold process tubes to support the endothermic chemical reaction. This radiant heat is similar to the heat one feels when standing a distance from a campfire where the air temperature is cold, but the heat can be clearly felt. In order to put this in context, the temperature range for basic petrochemical process heaters is typically less than to 1600°F, and they tend to have less corresponding potential heat loss. A reformer furnace could have fuel firing rate in excess of 1,000 MMBtu/hr. Since the firebox temperature in a reformer furnace is high it is important to minimize heat loss from the firebox and it is important to have sufficient insulation to reduce the external metal temperature to values recommended by American Petroleum Institute. A combination of high temperature brick and ceramic fiber insulation of sufficient thickness will be used along the walls, floor and ceiling of the firebox, to reduce firebox heat loss and to maximize reflection of radiant heat back to the process tubes.

The methanol steam reformer has 640 radiant tubes. If the process flow to each of the radiant tubes is not uniform, it will lead to uneven reaction in different tubes. Since reforming reaction is highly endothermic and the design of the firebox is such that each tube is to receive similar radiant heat energy, if the mass flow is not uniform, this will lead to uneven tube-wall metal temperatures resulting in overheating of the tubes not receiving the proper flow and eventually, their mechanical failure. The design rate of convective flow of gas down the tubes is essential to remove the heat by the endothermic chemical reaction to maintain the tube-walls at the design temperatures. Uniform feed flow to each radiant tube for maximum furnace efficiency is accomplished by ensuring that there is very little difference in the pressure drop down the length of the catalyst tubes. This is ensured by very careful loading of the catalyst in each tube and measuring the pressure drop down the length of each tube. The uniform distribution of the feed to the radiant tubes and the uniform heating of the tubes are critical to the successful operation of the catalytic reforming process of natural gas.

As part of this project, the existing older burners will be replaced with new, high efficiency burners. This specially designed flat flame burners will be installed in the roof of the firebox, firing downward. Burners will be designed to handle the whole range of fuels combusted.

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

The graphic below illustrates a 'cut-away' section of the top-fired reformer firebox.



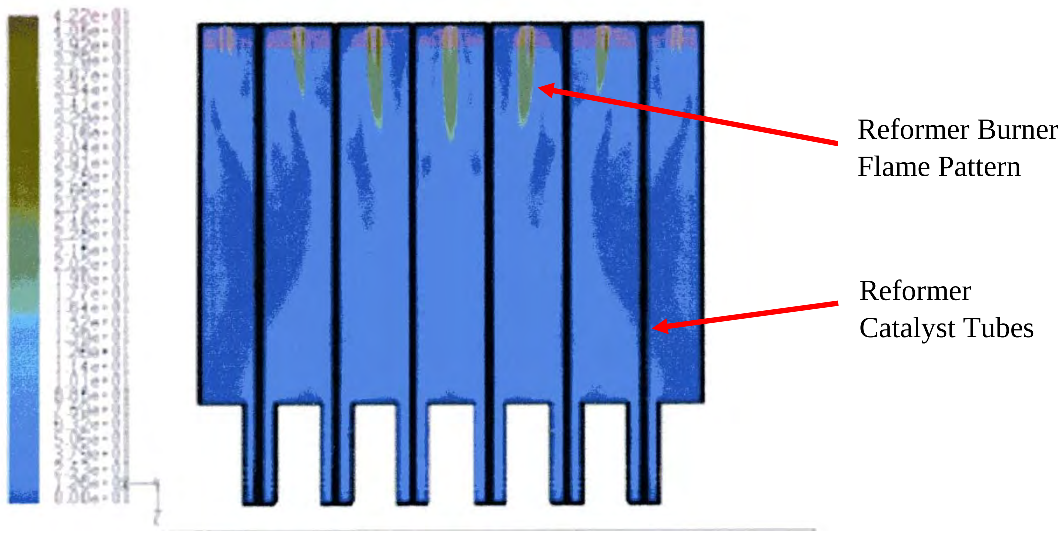
Inlet Pigtails to
ensure uniform flow
to each tube

Reformer Burners

Reformer Catalyst Tubes

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

The graphic below shows the CFD model profile of the top-fired reformer.



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

In a process heater which operates at lower temperatures, the convection section will be located directly above the radiant section. But the Convection section in a reformer furnace with high firebox temperatures will not be located directly on top of the radiant section. Direct radiation could lead to localized overheating, reduced heat transfer and premature failure of tubes with more frequent start-up and shutdown.

In order to reduce the formation of coke in the reformer tubes the plan is to use excess steam and the residence time at temperatures over 700°C will be minimized. The deposit of coke on the reformer tubes reduces the energy efficiency.

Synthesis gas must be desulfurized and subjected to shift conversion to obtain the required stoichiometry for methanol synthesis. The reforming reaction is performed inside the radiant tubes that are filled with reforming catalyst.

The basic criteria employed for developing our reformer design is that a methanol plant reformer should operate at maximum severity (temperature) consistent with proven equipment experience. Optimization studies have consistently shown that the higher cost of more exotic materials of construction is more than offset by the overall plant utility savings realized by high severity design.

Designing the reformer for conditions which maximize the carbon oxide (CO + CO2) yield/mole natural gas will minimize the amount of natural gas which must be fed to the reformer for a given methanol capacity. Carbon oxide yield is maximized by operating at high outlet temperature and low pressure. The selection of optimum reforming pressure is a balance between the favorable yield effect of low pressure operation, and the increased synthesis gas compressor power requirements. The maximum outlet temperature exit the furnace is controlled by the strength of the materials of construction--primarily tube metallurgy.

The other key variable in the design and operation of the reformer is the steam/carbon ratio (S/C). As the S/C ratio is reduced, the ratio of (CO/CO2) will increase. The carbon efficiency of the methanol synthesis loop is considerably higher for CO than CO2 (96% vs. 91% at EOR). As a result it is generally advantageous to operate the reformer at low S/C ratios to maximize the carbon utilization in the synthesis loop. The lower limit on S/C ratio is established at a level which is sufficiently removed from the point where carbon laydown on the catalyst is possible. Davy McKee, designer of the furnace, has indicated that serious carbon deposition is likely at S/C ratio of 1.8 - 2.0. This reformer is designed to operate at a S/C ratio of 2.8. An automatic shutdown is activated at a S/C ratio of 2.2.

The reforming catalyst and tube metallurgy selections are consistent with a high severity furnace operation. The catalysts used in the tubes are extremely active. Higher catalyst activity lowers the fluid temperature which will translate into reduced tube metal temperatures and longer tube life.

The convection section will have refractory along the walls of sufficient thickness to minimize heat loss from the convection walls and meet American Petroleum Institute recommendations for external skin temperature. The convection tubes will be located in a triangular pattern between rows of tube, or in triangular pitch, to maximize heat transfer to the tubes.

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

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

Heat recovery will be maximized for the range of operating conditions to get the flue gas exiting the convection section to the lowest temperature practicable. The temperature is sufficiently low that further heat recovery is impractical, resulting in water condensation. The design-basis of this Reforming Furnace was targeted to achieve 91% Thermal efficiency.

9.4.1.3.6 BEST OPERATIONAL PRACTICES

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

Oxygen Trim Controls – The excess oxygen is measured post-combustion and those results are used to control inlet combustion air volume to maintain high efficiency. Introduction of too much excess air increases the mass in the furnace to be heated and reduces efficiency. Oxygen trim control allows the excess oxygen to be controlled to optimum levels, thus allowing the furnace to operate at continuous high levels of efficiency. Individual burners are equipped with manually adjustable air control dampers to assure that air flow to burners is balanced. In addition, the reformer is fitted with both a forced draft fan (upstream) and an induced draft fan (downstream). This combination allows careful control of total air flow through the firebox, controlling excess oxygen, without creating excessive negative pressure in the firebox which would tend to draw unwanted air into the firebox.

Best operational practices do not reduce GHG emissions but rather prevent performance degradation that would allow GHG emissions to increase. Therefore they are assigned a 0% control effectiveness.

Adoption of the best operational practices along with energy efficient design and use of natural gas to fire the furnace, the emissions from the reformer furnace are estimated to be 826,600 TPY CO_2.

9.4.1.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

9.4.1.4.1 SUMMARY OF STEP 4

In Step 4 of this CO_2 BACT analysis, use of hydrogen as primary fuel is rejected due to collateral impacts. Those impacts are discussed below.

Carbon Capture and Storage (CCS) is rejected due to cost and collateral impacts. Those costs and collateral impacts are reviewed in detail below.

Fuels selection is determined to be the most appropriate CO_2 BACT for the furnace with a minimum reasonable control effectiveness of 12%. Energy efficient design at 0% maximum effectiveness and best operational practices with 0% effectiveness follow fuels selection in the hierarchy.

9.4.1.4.2 USE OF HYDROGEN AS PRIMARY FUEL FOR THE REFORMER FURNACE

Hydrogen could be used as the only fuel for the reformer furnace, providing 100% elimination of CO_2 from the flue gas, provided it was available and necessary firebox heat release and temperatures could be produced. Those aspects have not been further evaluated due to rejection on the basis of related impacts which show that collateral CO_2 emissions may be higher if hydrogen is burned as the primary fuel.

The National Renewable Energy Laboratory (NETL) has determined that the net effect of using hydrogen as a fuel when produced by the most common means, steam methane reforming, is an overall increased GHG emissions.[33] NETL concluded:

> *Although hydrogen is generally considered to be a clean fuel, it is important to recognize that its production may result in environmental consequences. Examining the resource consumption, energy requirements, and emissions from a life cycle point of view gives a complete picture of the environmental burdens associated with hydrogen production via steam methane reforming. The operation of the hydrogen plant itself produces very few emissions with the exception of CO_2. On a system basis, CO_2 is emitted in the largest quantity, accounting for 99 wt% of the total air emissions and 89% of the system GWP. Another air emission that effects the GWP of the system is CH_4, which primarily comes from the natural gas lost to the atmosphere during production and distribution. The energy balance of the system shows that for every 0.66 MJ of hydrogen produced, 1 MJ of fossil energy must be consumed (LHV basis).*

Therefore, while CO_2 emissions from the reformer furnace may be reduced by use of H_2 as the primary fuel, the collateral effect is that the H_2 will be produced elsewhere and the most common means of production generates more CO_2 than is offset by the H_2 combustion. Equistar may sell hydrogen as market demands for H_2 continue to increase, primarily for use as a feedstock for hydrodesulfurization at refineries for low sulfur fuel production.

The heat of combustion of methane is 11,953.6 cal/gm.[34]

Direct combustion of CH_4 to produce 1 MJ heat energy would require combustion of 20 grams of CH_4:

$1\text{x}10^6$ joules x 0.239 cal/joule x 1 gm CH_4 / 11,953.6 cal = 20 gm CH_4

20 gm CH_4 with complete combustion produces 55 grams of CO_2:

20 gm CH_4 x 12 gm C / 16 gm CH_4 x 44 gm CO_2 / 12 gm C = 55 gm CO_2

Production of hydrogen to supply 1 MJ heat energy would require combustion of enough methane to produce 83 grams of CO_2:

1 MJ from hydrogen / (0.66 MJ from hydrogen / 1 MJ from fossil fuel)[20] = 1.51 MJ from fossil fuel.

Verification: $1.51\text{x}10^6$ j x 0.239 cal/j x 1 gm CH_4/11,953.6 cal x 12 gm C/16 gm CH_4 * 44 gm CO_2/12 gm C = 83 gm CO_2

83 gm CO2 / 55 gm CO2 = 1.51

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[33] NETL publication, *Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming*, Page 23, Conclusions. http://www.nrel.gov/docs/fy01osti/27637.pdf

[34] Perry & Chilton, *Chemical Engineer's Handbook*, 5th Ed., c 1973, p. 3-145, Heats of Combustion

If one were to use methane, the lowest carbon common fossil fuel, to fire a steam methane reformer unit to produce hydrogen to be used as fuel, collateral CO_2 emissions from manufacture of that hydrogen, assuming identical manufacturing efficiencies, would be 51% higher than if the hydrogen had never been produced for use as a fuel.

In addition, the most common method of hydrogen production is steam methane reforming where the process parameters are adjusted to shift production to favor high concentrations of CO_2 in the synthesis gas for efficient separation of the hydrogen and CO_2. These units typically release the large volumes of CO_2 separated from the synthesis gas directly to the atmosphere. That is in addition to the CO_2 that is generated through combustion, making the collateral impacts much greater than the 51% demonstrated above.

Thus, it is technically infeasible to achieve a reduction in overall CO_2 emissions when collateral increases are considered. Use of hydrogen as a primary fuel is rejected due to collateral impacts on increased CO_2 emissions and overall GWP.

9.4.1.4.3 CARBON CAPTURE AND STORAGE

As described below, carbon capture and storage (CCS) is not economically feasible for this project based on the combination of the capture and transportation costs alone. In addition, the effectiveness of CCS is estimated to be near 57% when collateral increased CO_2 emissions are considered.

Capital cost for carbon capture is estimated to be more than $130-million, and for transportation is estimated at $21-million. The total cost for CCS is therefore estimated to be more than $150-million. The project cannot absorb the cost of CCS and remain financially viable. Specifically, the addition of the estimated CCS capital to the current project capital results in an increase more than 50% in the capital costs for the project to restart the existing unit. It follows that the additional capital results in a substantial decrease in the financial return on the project's capital expenditure even excluding high operating cost of a carbon capture unit. Therefore, CCS is rejected as a viable alternative due to capital cost alone.

Carbon Capture

Several methods are available for carbon capture, none of which Equistar has determined to be technically feasible as presented earlier in Step 2 of this analysis. Equistar has been unable to locate cost data, or specific technology details for the capture of CO_2 from flue gas generated by a similar sized furnace fired with natural gas and utilizing selective catalytic reduction technology for NOx control. Therefore, the cost data provided herein are based on ranges of costs provided in the cited references adjusted accordingly for differences between those projects and Equistar's facility.

Most carbon capture cost data that are available in literature are derived from power plant installations. Much of the data in literature are based on coal fired plants, including primarily integrated gasification combined cycle (IGCC) and pulverized coal (PC) plants. There are limited examples for natural gas combined cycle (NGCC) installations which would be more relevant to Equistar's reformer furnace, however remaining only distantly related. Power plants, with their relatively large fuel consumption when compared to the reformer furnace, and relatively high in stack CO_2 concentration (~10%vol CO_2 vs. 4%vol CO_2 minimum) could be reasonably expected to have much lower costs for CO_2 capture ($/ton basis) than would the reformer furnace.

It can be anticipated that a first of a kind (FOAK) installation, as one at Equistar's methanol plant would be, would have significantly higher costs than Nth of a kind (NOAK) installations where the technology is better developed. Where cost data are presented for a NOAK installation, those costs must be factored upward to reflect cost for a FOAK installation as Equistar's reformer carbon capture would be. One set of researchers estimated that costs could vary by a factor of 3 by stating:[35]

> *Based on these considerations a likely representative range of costs of abatement for capture (and excluding transport and storage) appears to be $100-150/tCO2 for first-of-a-kind plants and plausibly $30-50/tCO2 for nth-of-a-kind plants.*

For adjustment for coal fired plant examples, an understated upward adjustment of only 1.5x will be applied. Literature searches indicate CO_2 ranges in flue gas from coal fired plants ranges from roughly 7% to 14%. Equistar's reformer furnace flue gas will contain roughly 4% to 4.5% CO_2 depending on the fuel slate. At low concentrations, adsorption into amine solutions is much less effective than installation on coal fired units. With Equistar's flue gas having less than half the partial pressure of CO_2 at times as seen in coal fired plant fuel gas, the cost for equivalent control at the Equistar facility would require scale up for the needed additional amine contact. In process design, it is necessary to design for the entire range of normal operating parameters, and in this case, a relevant aspect is the low CO_2 concentration that would be observed when firing with a high molar percentage of hydrogen in the fuel gas. One in depth 2009 study estimated the cost of capture ($CA/tonne CO_2) of a 3.5% CO_2 stream to be roughly twice as much as a stream containing 9.2% CO_2.[36] For the purposes of cost estimation in this analysis, a factor of only 1.5 will be applied as opposed to 2.0 to account for the greater cost for capture of CO_2 from a dilute stream as opposed to a more concentrated flue gas stream that would be produced by a coal fired plant. The lower factor is chosen to avoid any appearance of over-estimation of costs. Those estimates cited in the reference included both capture and compression, but did not include transportation or storage.

For adjusting cost for the size of the unit, in terms of CO_2 mass to be collected, the "0.6 factor model" or "0.6 factor rule," will be used. This is a commonly used model for roughly estimating relative capital costs of processing plants based on size of those plants. The cost adjustment is the ratio of Equistar's unit CO_2 generation divided by the reference case CO_2 generation, and that result is raised to the 0.6 power then multiplied by the reference model cost. This will be applied to each case analyzed to increase or decrease the estimated capital cost appropriately.

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[35] Al-Juaied, Mohammed A and Whitmore, Adam, "*Realistic Costs of Carbon Capture*" Discussion Paper 2009-08, Cambridge, Mass.: Belfer Center for Science and International Affairs, July 2009, Abstract, p ii, http://belfercenter.ksg.harvard.edu/files/2009_AlJuaied_Whitmore_Realistic_Costs_of_Carbon_Capture_web.pdf

[36] Ordorica-Garcia , Wong, Faltinson, *CO2 Supply from the Fort McMurray Area , 2005-2020*, Table 3.4. Estimate of CO2 cost for three CO2 concentrations of 3.5%, 9.2% and 18.6%.

For this evaluation, Equistar has researched assorted references with cost data for CCS installations and academic papers that also provide cost data. Some of those data are provided below with indications of appropriate adjustment for the factors provided in the discussion above. The appropriate adjustments and the justifications for their use are provided in each case.

BACT Table 5: Slate of Adjustments for Capital Cost

Cost Factor	**Data Source**	**Cost Adjustment for Equistar**
Fuel type	Coal (IGCC or PC)	Upward 1.5x due to CO_2 partial pressure difference in the flue gas.
	Natural gas (NGCC)	No change (conservative)
Size of unit	CO_2 generation or firing rate	Usually downward (Equistar CO_2/Reference CO_2)^0.6
Temporal basis	FOAK or current operation	No change
	NOAK	Upward 1.5x to 3x due to higher FOAK basis

Four cases are provided below for estimation of capital cost of the capture and compression facilities alone. The CO_2 generated by the reformer furnace is projected to be 826,600 tons per year while firing natural gas at maximum rates. With 90% capture this is 2038 tons per day captured. The estimated cost for a unit to capture and compress this CO_2 suitable for the Equistar methanol unit restart project ranges from $130-million to over $620-million.

CASE 1

This example is taken from a cost evaluation presented by Ahmed Aboudheir and Gavin McIntyre[37] on the cost for installation of a CCS system alone on a coal fired power plant. The plant is designed to capture 3307 tons per day of CO2 at 90% recovery rate. This would be a FOAK installation. Because this is a capital cost alone, no adjustment is made for power to operate the recovery system, for CO2 transportation or for storage.

Size of Unit:	3307 tons/per day
Fuel type:	Coal (12% CO_2 in flue gas)
Capital Cost:	$165- million

Adjustments to cost estimate for Equistar case:

Size of unit:	(2038/3307)^0.6 = 0.75
Fuel type:	1.5

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[37] Aboudheir and McIntyre, Industrial Design and Optimization of CO2 Capture, Dehydration, and Compression Facilities. http://www.bre.com/portals/0/technicalarticles/INDUSTRIAL%20DESIGN%20AND%20OPTIMIZATION%20OF%20CO2%20CAPTURE,%20DEHYDRATION,%20AND%20COMPRESSION%20FACILITIES.pdf

Capita; cost = $165-million x 0.75 x 1.5 = **$185-million**

CASE 2

Case 2 is also taken from Aboudheir and McIntyre's evaluation of capital costs. Case 2 is a Natural Gas Combines Cycle (NGCC) plant of the same size as the coal fired plant presented in case 1. Being a NGCC plant, no adjustment is made for fuel type (reported 4% CO2 in stack). This would be a FOAK installation. Because this is a capital cost alone, no adjustment is made for power to operate the recovery system, for CO2 transportation or for storage.

Size of Unit:	3307 tons/per day
Capital Cost:	$227-million

Adjustments to cost estimate for Equistar unit:

Size of unit: (2038/3307)^0.6 = 0.75
Capital cost = $227-million x 0.75 = **$170-million**

CASE 3

This case was presented by Al-Juaied and Whitmore[38] in 2009 and relates to a natural gas fired combined heat and power unit at the Mongstad, Bergen, Norway refinery. The unit is a FOAK unit, capturing a total of 1.2-million tonnes per year of CO2 from the CHP unit. Being natural gas fired there is no adjustment for fuel type. 50% of the $1.75-billion is for the capture facilities associated with the CHP unit.

Size of Unit:	1.2-million tonnes x 1.102 ton/tonne /365 day/yr = 3,623 tpd
Capital cost:	$1.75 billion x 0.50 = $875-million

Adjustments to cost estimate for Equistar unit:

Size of Unit: (2038/3623)^0.6 = 0.71

Capital cost = $875-million x 0.71 = **$621-million**

CASE 4

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[38] Al-Juaied, Mohammed A and Whitmore, Adam, "Realistic Costs of Carbon Capture" Discussion Paper 2009-08, Cambridge, Mass.: Belfer Center for Science and International Affairs, July 2009. http://belfercenter.ksg.harvard.edu/files/2009_AlJuaied_Whitmore_Realistic_Costs_of_Carbon_Capture_web.pdf

This case was also presented by Al-Juaied and Whitmore.[38] It is a Saudi Aramaco gas turbine installation, firing natural gas, capturing 1.3 million tonnes per year of CO_2 with a capital cost of $194-million.

Size of Unit: 1.3-million tonnes x 1.102 ton/tonne /365 day/yr =
3925 tpd
Capital cost: $194 million x 0.50 = $875-million

Adjustments to cost estimate for Equistar unit:

Size of Unit: (2038/3925)^0.6 = 0.67

Capital cost = $194-million x 0.67 = **$130-million**

Based on referencing these coal and natural gas fired power plants, using factors to prevent any appearance of over-stating costs, the estimated cost for an Equistar FOAK facility for capture of CO_2 at 90% effectiveness, is between $130-million and $185-million. The highest derived cost is rejected as an outlier. It is likely that a more rigorous cost estimate would result in a substantially higher cost range, although not as high as the highest cost derived in the four cases above.

Transportation

The CO_2 emissions from the reformer furnace have been estimated to be approximately 826,600 tons per year. With 90% capture, 743,940 tons per year or 2,038 tons per day would require transportation. The closest tie-in point to a CO2 transportation pipeline, regardless of the end-point destination of the CO_2 is the Denbury Green pipeline. The logical tie-in point is approximately 30 miles south-southeast of Equistar's Channelview site. NETL guidance[39] suggests that an 8" diameter pipeline would be appropriate for this transport need. NETL guidance on pipeline costs yields a final total capital cost of $21.2-million and Operation and Maintenance costs of $259,000/year.

The following cost estimates in BACT Table 6 are based on formulae provided by NETL.[40]

BACT Table 6: Estimates for CO_2 Transport from Equistar Channelview to Dickinson, TX Area.

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[39] Figure 4: Pipe Diameter as a Function of CO2 Flow Rate, *Estimating Carbon Dioxide Transport and Storage Costs*, Page 11. http://www.netl.doe.gov/energy-analyses/pubs/QGESStransport.pdf

[40] Table 2: Pipeline Cost Breakdown [4,6,7], *Estimating Carbon Dioxide Transport and Storage Costs*, Page 5. http://www.netl.doe.gov/energy-analyses/pubs/QGESStransport.pdf

Cost Type	Units	Cost	Est. Cost
Pipeline Costs			
Materials	\$ Diameter (inches) Length (miles)	$\$64,632 + \$1.85 \text{ x } L\ (330.5 \text{ x } D^2 + 686.7 \text{ x } D + 29,960) =$	\$ 3,039,743
Labor	\$ Diameter (inches) Length (miles)	$\$341,627 + \$1.85 \text{ x } L \text{ x } (343.2 \text{ x } D^2 + 2,074 \text{ x } D + 170,013) =$	\$ 11,917,251
Miscellaneous	\$ Diameter (inches) Length (miles)	\$150,166 + \$1.58 x L x (8,417 x D + 7,234) =	\$ 3,684,784
Right of Way	\$ Diameter (inches) Length (miles)	\$48,037 + \$1.20 x L x (577 x D + 29,788) =	\$ 1,286,581
Other Capital			
CO2 Surge Tank	\$	\$1,150,636	\$1,150,636
Pipeline Control System	\$	\$110,632	\$110,632
O&M			
Fixed O&M	\$/mile/year	\$8,632	\$258,960

Storage

Equistar owns and operates salt dome caverns for storage of light hydrocarbons and that technology could possibly be employed for CO_2 storage. Due to familiarity with the technology and uncertainty of the other options, this storage option is further evaluated. Based Equistar's 2006 study of the total cost for a new 2.65-million barrel storage cavern, it is estimated that a storage cavern of sufficient size to store 20 years of captured CO_2 from the new furnace would have a capital cost of more than \$1-billion (2006 dollars). It is assumed that solution mining to produce a cavern for CO_2 storage is not substantially different in cost than for a hydrocarbon storage cavern.

Captured CO_2 = 743,940 tons per year

Lifetime captured CO_2 = 20 years x 743,940 tpy = 29,758,000,000 pounds

CO_2 density at supercritical conditions, well depth >3,000 ft. ~42 lb/ft^3

Volume needed = 29,758,000,000 lb / 42 lb/ft^3 = 709,000,000 ft^3
= 709,000,000 ft3 / 5.61 ft3/barrel = 126 million barrels.

Based on size alone, this project is 48 times larger than the project evaluated in 2006.

Development cost (fixed) \$15-million

Well installation = 48 x \$37-million = \$1.77-billion.

Total cost is approximately \$1.8-billion. (2006 dollars)

For storage alone, that cost is clearly prohibitive in comparison to the other options. For the purposes of this evaluation, it is assumed that CO_2, if used for enhanced oil recovery (EOR) would generate revenues that would at least partially offset the cost for storage and storage monitoring. If saline aquifer or un-mineable coal seam options were selected to complete the CCS strategy, additional costs would need to be added to the analysis for injection wells, storage rights, and long term monitoring.

Because EOR costs would be partially offset by revenues generated by recovered oil, the CCS analysis assumes zero cost for storage.

9.4.1.4.4 FUELS SELECTION

Equistar intends to employ fuels selection as described in Steps 2 and 3 of this Furnace CO_2 BACT evaluation.

9.4.1.4.5 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE REFORMER FURNACE

The reformer furnace at Equistar's Channelview Plant incorporates the energy efficiencies described in Steps 2 and 3.

9.4.1.4.6 BEST OPERATIONAL PRACTICES

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

9.4.1.5 SELECTION OF CO_2 BACT (STEP 5)

With the rejection of hydrogen use as a primary fuel, and of CCS as an option for control of CO_2 emissions in step 4 of this BACT analysis, the remaining options include fuels selection, energy efficient design and adoption of best operational practices. Consistent with EPA guidance for selection of BACT, fuels selection is BACT for control of CO_2 emissions associated with furnace operation. Furthermore, Equistar has chosen to control CO_2 emissions using all three of these methods for limiting CO_2 emissions relating to operation of the methanol unit Reformer furnace. Emissions from the reformer furnace with incorporation of the three technologies is estimated to be no more than 826,600 tons per year.

BACT Table 7: Summary of Reformer Furnace CO2 Emissions w/ BACT Applied

Source	Description	TPY CO_2	TPY CO2e	Lb/hr CO_2	Lb/hr CO2e
EHTF7001	Reformer Furnace	826,600	826,600	189,900	189,000

With respect to operational controls and best practices, Equistar proposes the following:

PREVENTATIVE MAINTENANCE AND TUNING/CALIBRATION	**BEST PRACTICE**
Crossover and Stack O2 analyzers	Monthly calibration, check filters, etc.
Fuel gas analyzer	Classify as environmentally critical instrument and thus receive an increased priority for preventative maintenance and repairs.
	Monthly calibration, check filters, etc.
Fuel gas flow meter	Classify as environmentally critical instruments and thus receive an increased priority for preventative maintenance and repairs.
	Biannual calibration
Burner condition	Visually inspect flame patterns for efficiency to maintain combustion efficiency
OPERATION	**BEST PRACTICE/CONTROL**
Reformer Temperature Profile	Maintain uniform temperature profile for efficient combustion
Oxygen control	Control O2 based on O2 analyzer output to assure high efficiency combustion.

9.4.2 REFORMER FURNACE - CH_4 BACT

9.4.2.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Summary of Step 1

Control options for CH_4 emissions from the reformer stack include actual direct control, elimination of the capability to emit CH_4, and steps to minimize the generation of CH_4. Five methods were identified and were all carried to Step 2 in the process.

Available Controls

Available control options for minimizing CH_4 emissions from the Reformer furnace include:

- Post-combustion catalytic oxidation

- Post-combustion catalytic oxidation provides rapid conversion of a hydrocarbon into CO2 and water vapor in the presence of available oxygen. This is direct control of CH4, producing a second GHG, CO2 with a net decrease in CO2e emissions.
- Use hydrogen as the primary fuel for the reformer furnace.
- In its combustion, hydrogen produces no CH4. This method of control is elimination of the capacity to produce CH4 emissions.
- Burn low CH4 generating fuel.
- CH4 emissions estimating methods published by EPA[41] indicate that different fuels produce varying amounts of CH4 that may be emitted. Selection of a low CH4 emitting fuel minimizes CH4 emissions.
- Installation of energy efficient options for the reformer furnace
- Improved energy efficiency reduces overall fuel combustion demands for a given process production rate. By combusting less fuel, it is reasonably projected that less CH4 would be emitted.
- Best Operational Practices
- Best operational practices preserve energy efficiency and thus maintain low overall fuel combustion demands for a given process production rate. By combusting less fuel, it is reasonably projected that less CH4 would be emitted.

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[41] 40 CFR Part 98, Subpart C.

9.4.2.2 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

Summary of Step 2

In Step 2 of the five-step BACT evaluation for control of CH_4 emissions from the reformer furnace stack, post-combustion catalytic oxidation and use of hydrogen as the primary fuel are both rejected as technically infeasible. Use of low CH_4 generating fuel, energy efficiency and best operational practices are technically feasible and are carried forward to Step 3.

9.4.2.2.1 POST-COMBUSTION CATALYTIC OXIDATION

The reformer furnace flue gas temperature design temperature is in the range of 270° to 305°F (132°C to 152°C). It is expected to contain about 1 ppmv CH_4.

The temperature reflects the highly efficient furnace operation in which heat loss via furnace flue gas is minimized. However, this temperature is below the lowest operating temperature for catalytic oxidation found in literature research. Typical low ends of operating temperature ranges for catalytic oxidation are 250°C or higher. In addition, the flue gas CH_4 concentration is about two orders of magnitude below the lower end of VOC concentration in streams which would typically be fitted with catalytic oxidation for control.[42]

The reformer furnace is essentially a highly efficient thermal oxidizer, achieving destruction efficiencies of greater than 99.9% for the methane fuel. Addition of post-combustion catalytic oxidation on this reformer furnace for control of CH_4 is technically infeasible and will not be considered in subsequent steps of this analysis.

9.4.2.2.2 USE OF HYDROGEN AS THE PRIMARY FUEL

During combustion, hydrogen generates no CH_4. Hydrogen could be used as a fuel provided it was available and that necessary firebox heat release and temperatures could be produced through hydrogen firing. Those aspects have not been further evaluated due to subsequent rejection on the basis of collateral impacts as presented below.

Hydrogen combustion for its fuel value generates no CH_4 directly. However, the National Renewable Energy Laboratory (NETL) has determined that the net effect of using hydrogen as a fuel when produced by the most common means, natural gas steam reforming, is an overall increase global warming potential (GWP). NETL concluded:

> *Although hydrogen is generally considered to be a clean fuel, it is important to recognize that its production may result in environmental consequences.*

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[42] US EPA, APTI 415, Control of Gaseous Emissions, Chapter 6, P 6-14. http://www.epa.gov/apti/Materials/APTI%20415%20student/415%20Student%20Manual/415_Chapter%206_final.pdf

> *Examining the resource consumption, energy requirements, and emissions from a life cycle point of view gives a complete picture of the environmental burdens associated with hydrogen production via steam methane reforming. The operation of the hydrogen plant itself produces very few emissions with the exception of CO_2. On a system basis, CO_2 is emitted in the largest quantity, accounting for 99 wt% of the total air emissions and 89% of the system GWP. Another air emission that effects the GWP of the system is CH_4, which primarily comes from the natural gas lost to the atmosphere during production and distribution. The energy balance of the system shows that for every 0.66 MJ of hydrogen produced, 1 MJ of fossil energy must be consumed (LHV basis).*[43]

On-purpose hydrogen production through steam methane reforming, the most common process used for commercial production of hydrogen, will also generate CH_4 emissions. If one were to use methane, the lowest carbon common fossil fuel and coincidentally the fuel that produces the lowest CH_4 emissions, to fire a steam methane reformer unit to produce hydrogen to be used as fuel, collateral CH_4 emissions from manufacture of that hydrogen, assuming identical manufacturing efficiencies, would be roughly 50% higher than if the hydrogen had never been produced for use as a fuel.

Therefore, while CH_4 emissions from the subject source may be reduced by use of hydrogen as the primary fuel, the collateral effect is greater CH_4 emissions elsewhere. Given the global nature of GHG emissions this option is rejected due to the increased CH_4 emissions from the hydrogen generating source beyond the increase that would be seen if the Reformer furnace was fired with natural gas alone. In addition, as presented in the CO_2 BACT discussion in this document, collateral CO_2 emissions also increase if hydrogen is used as the primary fuel. Use of hydrogen as the primary fuel for the Reformer furnace would actually increase overall CO2e emissions and is not progressed beyond this step of the top-down BACT analysis.

Furthermore, the most common method of hydrogen production is steam methane reforming where the process parameters are adjusted to shift production to favor high concentrations of CO_2 in the synthesis gas for efficient separation of the hydrogen and CO_2. These units typically release the large volumes of CO_2 separated from the synthesis gas directly to the atmosphere, increasing the CO2e emissions even more.

Use of hydrogen as a primary fuel is rejected due to collateral impacts on increased CH_4 emissions and overall GWP.

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[43] NETL publication, *Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming*, Page 23, Conclusions. http://www.nrel.gov/docs/fy01osti/27637.pdf

9.4.2.2.3 BURN LOW CH_4 GENERATING FUEL.

Data collected by EPA and presented in Tables C-1 and C-2 of 40 CFR Part 98, Subpart C for purposes of estimating emissions of GHGs indicate that a switch from natural gas firing to another fuel would actually increase emissions of CO_2, CH_4 and N_2O. The GHG generation rates below are taken from the two emissions factor tables in 40 CFR Part 98, Subpart C, shown below as BACT Table 8.

BACT Table 8: Emissions factors from 40 CFR Part 98, Subpart C

Fuel	CO_2 kg/MMBtu	CH_4 kg/MMBtu	N_2O Kg/MMBtu
Methane	53.02	1.0×10^{-3}	1.0×10^{-4}
Ethane	62.64	3.0×10^{-3}	6.0×10^{-4}

Because a switch to an available fuel other than natural gas would increase CH_4 emissions, use of natural gas as a fuel results in minimized CH_4 emissions. This is a feasible method to minimize CH_4 emissions.

In addition, when hydrogen is routed to the furnace fuel system, this further reduces CH_4 emissions potential.

9.4.2.2.4 INSTALLATION OF ENERGY EFFICIENT OPTIONS FOR THE REFORMER FURNACE

As presented in the discussion of CO_2 BACT, minimization of GHG emissions through use of energy efficient design is effective and will be employed in the reformer furnace. This will limit overall firing rate for a given production volume and corresponding emissions of CH_4. This option is carried forward in the analysis.

9.4.2.2.5 BEST OPERATIONAL PRACTICES

As presented in the discussion of CO_2 control through use best operational practices, this method will be employed to prevent energy efficiency degradation of the Reformer furnace, and thereby prevents CH_4 emissions increase. This option is carried forward in the analysis.

9.4.2.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The three remaining technologies are linked in that the furnace is designed for natural gas and high hydrogen fuel gas combustion at peak energy efficiency, with the employment of best operational practices assures that the energy efficiency is retained. All three methods of control will be employed and therefore ranking is unnecessary and irrelevant.

9.4.2.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The three remaining technologies are linked in that the furnace is designed for natural gas and high hydrogen fuel gas combustion at peak energy efficiency, with the employment of best operational practices assures that the energy efficiency is retained. All three methods of control will be employed and therefore further evaluation is unnecessary and irrelevant.

9.4.2.5 SELECTION OF CH_4 BACT (STEP 5)

The combination of the three remaining technologies will be adopted as BACT.

Equistar will:

- Fire the reformer furnace with natural gas and/or hydrogen rich fuel gas,
- Use the existing energy efficient design, and
- Conform to Best Operational Practices.

BACT Table 9: Summary of Furnace CH_4 Emissions w/ BACT Applied

Source	Description	TPY CH_4	TPY CO2e	lb/hr CH_4	lb/hr CO2e
EHTF7001	Reformer Furnace	15.6	327	3.56	74.70

With respect to operational controls and best practices, Equistar proposes the following:

PREVENTATIVE MAINTENANCE AND TUNING/CALIBRATION	**BEST PRACTICE**
Crossover and Stack O2 analyzers	Monthly calibration, check filters, etc.
Fuel gas analyzer	Classify as environmentally critical instrument and thus receive an increased priority for preventative maintenance and repairs.
	Monthly calibration, check filters, etc.
Fuel gas flow meter	Classify as environmentally critical instruments and thus receive an increased priority for preventative maintenance and repairs.
	Biannual calibration
Burner condition	Visually inspect flame patterns for efficiency to maintain combustion efficiency
OPERATION	**BEST PRACTICE/CONTROL**
Reformer Temperature Profile	Maintain uniform temperature profile for efficient combustion
Oxygen control	Control O2 based on O2 analyzer output to assure high efficiency combustion.

9.4.3 REFORMER FURNACE - N2O BACT

9.4.3.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

- N2O catalysts to decompose N2O into nitrogen and oxygen.
- Low NOx burner selection to limit formation of NOx (including N2O) emissions.
- Energy efficient design and good operating practices to minimize firing necessary for a given production volume.

9.4.3.2 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

N_2O catalysts have been used to reduce N2O emissions from adipic acid and nitric acid plants.[44] There is no indication that these catalysts have been used to control N_2O emissions from reformer furnace flue gas. In addition, the very low N_2O concentrations present in the exhaust stream would make installation of N_2O catalysts technically infeasible. In comparison, the application of a catalyst in the nitric acid industry sector has been effective due to the high (1,000-2,000 ppm) N_2O concentration in those exhaust streams. N_2O catalysts are eliminated as a technically feasible option for the proposed project.

With N_2O catalysts eliminated, low-NOx, efficient burner technology selection and energy efficient operating practices are the only available and technically feasible control options for N_2O reduction from the Reformer furnace. Both are carried to Step 3.

9.4.3.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

Low-NOx, efficient burner selection and energy efficient design and good operating practices will be adopted as BACT for N2O control from the Reformer. No ranking is necessary.

9.4.3.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

Low-NOx, efficient burner selection and energy efficient design and operating practices will be adopted as BACT for N2O control from the Reformer. No further evaluation is necessary.

9.4.3.5 SELECTION OF N2O BACT (STEP 5)

Equistar will select efficient natural gas burners that meet the design requirements for the proposed project. Furthermore, Equistar will use the existing energy efficient furnace design and adopt good operating practices.

N2O emissions from the furnace are anticipated to be no more than 0.53 TPY based on 40 CFR Part 98 dated December 17, 2010, Table C-2 of Subpart C - Default CH4 and N2O Emission Factors for Various Types of Fuel. Emission factors for natural gas (unspecified heat value, weighted U.S.

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[44] http://www.catalysts.basf.com/p02/USWeb-Internet/catalysts/e/content/microsites/catalysts/news/success-stories/reduce-emissions

average) are used. In comparison to the total CO2e emissions associated with the project, the combined furnace N_2O emissions represent less than 1/1000th of the unit CO2e emissions.

BACT Table 10: Summary of Reformer N_2O Emissions w/ BACT Applied

Source	Description	TPY N_2O	TPY CO2e	lb/hr N_2O	lb/hr CO2e
EHTF7001	Reformer Furnace	1.6	483	0.40	110

With respect to operational controls and best practices, Equistar proposes the following:

PREVENTATIVE MAINTENANCE AND TUNING/CALIBRATION	**BEST PRACTICE**
Crossover and Stack O2 analyzers	Monthly calibration, check filters, etc.
Fuel gas analyzer	Classify as environmentally critical instrument and thus receive an increased priority for preventative maintenance and repairs.
	Monthly calibration, check filters, etc.
Fuel gas flow meter	Classify as environmentally critical instruments and thus receive an increased priority for preventative maintenance and repairs.
	Biannual calibration
Burner condition	Visually inspect flame patterns for efficiency to maintain combustion efficiency
OPERATION	**BEST PRACTICE/CONTROL**
Reformer Temperature Profile	Maintain uniform temperature profile for efficient combustion
Oxygen control	Control O2 based on O2 analyzer output to assure high efficiency combustion.

9.5 FLARE – GHG BACT

Greenhouse Gas (GHG) Best Available Control Technology (BACT) for the flare has been evaluated via a "top-down" five-step approach. Each of those five steps is outlined in subsequent sections below. The analysis has been conducted for each of the three GHGs emitted. That analysis led to the conclusion that BACT for flare GHG emissions is use of a current flare design (CH_4), waste gas minimization (CO_2, CH_4, N_2O), and use of natural gas fired pilots (CO_2).

The methanol unit will have two new flares constructed as part of the project. One of these flares is a continuous flare, meaning that it be continuously situated to receive waste gases from the methanol unit. The other is for high waste gas flow rates that exceed the capacity of the continuous flare. During normal operation there are no waste gas flows produced by the unit that are routed to the flares. The only gases flowing continuously to the flare are pilot gas and sweep gas on the continuous flare.

It is important to note that the only increase in flare emissions associated with this project is from maintenance, startup and shutdown (MSS) activities, and from existing East Plant Flare 17E01, which will control methanol loading emissions.

GREENHOUSE GASES
MAXIMUM HOURLY EMISSION RATE

AIR CONTAMINANT DATA

1. Emission Point			2. Component of Air Contaminant Name	3. Air Contaminant Maximum Emission Rate	
(A) EPN	**(B) FIN**	**(C) NAME**		**lb/hr (A)**	**CO_2e lb/hr (B)**
EHTF7001	HTF7001	Reformer Furnace	CO_2e	188,904	188,904
			CO_2	188,721	188,721
			N_2O	0.4	110.3
			CH_4	3.6	74.7
EMEOHFLARE	MEOHFLARE	Methanol Flare	CO_2e	135,989	135,989
		MSS - Reformer Start-up	CO_2	134,248	134,248
			N_2O	0.49	152.63
			CH_4	76	1,588
EMEOHFLARE	MEOHFLARE	Methanol Flare	CO_2e	10,233	10,233
		MSS - Column Start-up	CO_2	10,193	10,193
			N_2O	0.10	29.8
			CH_4	0.48	10.1
EMEOHFLARE	MEOHFLARE	Methanol Flare	CO_2e	3,572	3,572
		MSS - Unit S/D & Clearin	CO_2	3,433	3,433
			N_2O	0	12
			CH_4	6	127
EMEOHFLARE	MEOHFLARE	Methanol Flare	CO_2e	503	503
		Nat Gas Sweep	CO_2	502	502
			N_2O	0.00	0.3
			CH_4	0	0.2
EMEOHFLARE	MEOHFLARE	Methanol Flare	CO_2e	136,491	136,491
		Worst Case (Reformer S/U	CO_2	134,750	134,750
		Nat Gas Sweep)	N_2O	0.49	153
			CH_4	76	1,588.5
EEMERFLARE	EMERFLAREP	Methanol Emergency Fla	CO_2e	46	46
		Pilots	CO_2	46	46
			N_2O	0.00	0.02
			CH_4	0.00	0.02
17E01	17FL1701F,	East Plant Flare - Product Loading w/Chiller	CO_2e	5.1	5.1
			CO_2	5.1	5.1
			N_2O	0.00	0.01
			CH_4	0.00	0.01
		East Plant Flare - Product Loading w/out Chiller	CO2e	51.4	51.4
			CO2	51.4	51.4
			N_2O	0.00	0.15
			CH_4	0.00	0.05
EFUGMEOH	FUGMEOH	Equipment Fugitives	CO_2e	32	32
			CO_2	9	9
			N_2O	0	0
			CH_4	1.1	23

9.5.1 FLARES - CO2 BACT EVALUATION

CO_2 emissions from flaring process gas are produced from the combustion of carbon-containing compounds (CO, VOCs, CH_4) present in the process gas streams and the pilot fuel. The quantity of CO_2 emissions from the flare are based on the estimated flow rates and composition of flared carbon-containing gases.

The Methanol Unit will be equipped with two new flares. One is a continuous flare and the other is for emergency operations if the capacity of the continuous flare is exceeded during extreme flaring event. As mentioned previously there are no continuous flows of waste gases to the flares.

In addition, an existing flare, East Plant Flare 17E01, will be used to control methanol emissions during loading operations. Because this flare is an existing control device, no BACT evaluation is being conducted for that flare.

The flares are examples of control devices in which the control of one GHG pollutant causes collateral GHG emission of another pollutant. Specifically, the control of CH_4 in the process gas at the flare results in the creation of additional CO_2 emissions through combustion of the CH4. However, given the relative GWPs of CO2 and CH4, it is appropriate to apply combustion controls to CH4 emissions even though it will form additional CO2 emissions.

For example, combusting 1 lb of CH4 (21 lb CO2e) at the flare at 99% efficiency will result in 0.01 lb CH4 and 2.75 lb CO2 (0.01 lb CH_4 x 21 CO_2e/CH_4 + 2.75 lb CO_2 x 1 CO_2e/CO_2 = 2.96 lb CO_2e), and therefore, on a CO_2e emissions basis, combustion control of CH_4 is preferable to venting the CH_4 without control.

9.5.1.1 STEP 1 - IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES

The following potential CO_2 control strategies for the flares were considered as part of this BACT analysis:

- Flare Gas Recovery
- Waste Gas Minimization
- Use of Natural Gas for Flare Pilots

9.5.1.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

9.5.1.2.1 Flare Gas Recovery

Flaring can be reduced by installation of commercially available equipment to construct a recovery system, including recovery compressors, flow controls and piping systems. The recovered gas is then utilized by introducing it into the fuel system to supplement the normally used fuels, or recycled into the process.

This methanol unit has no continuous flows of waste gases to the flares and other flows to the flares are intermittent, consisting of MSS waste gases and upset/emergency flows. Due to the absence of any continuous flow, and the fact that when there will be waste gas flows, they will be highly variable both in rate and composition based on the source, this option is both impractical and infeasible. The primary technical barriers are that any effective flare gas recovery system would need to switch on immediately to capture waste gas, the disposition of the waste gas would need to have sufficient capacitance to accommodate the intermittent and potentially significant gas flow, and the disposition would need to be able to take variability of composition.

9.5.1.2.2 Waste Gas Minimization

Waste gas minimization is technically feasible and is incorporated into the design of the unit. As such, certain gas streams that might otherwise be flared are returned to process.

9.5.1.2.3 Use of Natural Gas for Pilots

Equistar intends to use natural gas for pilot fuel.

9.5.1.3 STEP 3 – RANK REMAINING CONTROL OPTIONS BY EFFECTIVENESS

Equistar intends to employ both technically feasible controls for flare CO_2 emissions; waste gas minimization and use of natural gas as pilot fuel. Ranking is unnecessary.

9.5.1.4 STEP 4 – TOP-DOWN EVALUATION OF CONTROL OPTIONS

Because Equistar intends to use the technically feasible option for CO_2 control, no further evaluation is necessary. No significant adverse energy or environmental impacts (that would influence the GHG BACT selection process) associated with operating a flare to control process gas or using good flare design are expected.

9.5.1.5 STEP 5 – SELECT CO_2 BACT FOR FLARE

Equistar's methanol unit design minimizes flows of waste gases to the flare. This control is incorporated into the unit design.

Natural gas-fired pilots and good flare design will be applied as CO_2 GHG BACT for the flares in order to minimize emissions from the flares.

BACT Table 12: Summary of Flare CO_2 Emissions w/ BACT Applied

Source	Description	TPY CO_2	TPY CO2e	lb/hr CO_2	lb/hr CO2e
EMEOHFLARE	Methanol Flare	3733	3733	134,750	134,750
EEMERFLARE	Emergency Flare Pilots	200	200	46	46
17E01	East Plant Flare - Product Loading	39	39	5.1	5.1

9.5.2 FLARES – CH4 BACT EVALUATION

Contributions to CH_4 emissions from the flares include:

- Incomplete combustion of CH_4 in the process gas and supplemental natural gas fuel, and
- CH_4 formed as a byproduct of incomplete hydrocarbon combustion from the flare pilots.

Primary CH_4 emissions are calculated based on the CH_4 content of flared process gas and supplemental natural gas fuel and the CH_4 combustion efficiency for a well-designed flare, 99 percent. Secondary CH_4 emissions from incomplete combustion of non-CH_4 hydrocarbons in the pilot gas are calculated based on the MRR emission factor for CH_4 from natural gas combustion. In general, completeness of combustion and CH_4 emissions from a flare is governed by flame temperature, residence time in the combustion zone, turbulent mixing of the components to complete the oxidation reaction, and available oxygen for free radical formation.[45]

9.5.2.1 STEP 1 – IDENTIFY AVAILABLE CONTROL OPTIONS

The following potential CH_4 control strategies for the flares were considered as part of this BACT analysis:

- ▲ Flare Gas Recovery
- ▲ Good Flare Design
- ▲ Waste Gas Minimization
- ▲ Use of Low Carbon Fuel for Pilots

9.5.2.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

9.5.2.2.1 FLARE GAS RECOVERY

Flaring can be reduced by installation of commercially available equipment to construct a recovery system, including recovery compressors, flow controls and piping systems. The recovered gas is then utilized by introducing it into the fuel system to supplement the normally used fuels, or recycled into the process.

This methanol unit has no continuous flows of waste gases to the flares and other flows to the flares are intermittent, consisting of MSS waste gases and upset/emergency flows. Due to the absence of any continuous flow, and the fact that when there will be waste gas flows, they will be highly variable both in rate and composition based on the source, this option is both impractical and infeasible. The primary technical barriers are that any effective flare gas recovery system would need to switch on immediately to capture waste gas, the disposition of the waste gas would need to have sufficient capacitance to accommodate the intermittent and potentially significant gas flow, and the disposition would need to be able to take variability of composition.

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

9.5.2.2.2 USE OF A GOOD FLARE DESIGN

Use of a good flare design assures more complete combustion of CH4 and combustion of other hydrocarbons. This technology is considered feasible.

9.5.2.2.3 WASTE GAS MINIMIZATION

Waste gas minimization is technically feasible and is incorporated into the design of the unit. As such, certain gas streams that might otherwise be flared are returned to process.

9.5.2.2.4 USE OF LOW CARBON FUEL FOR PILOTS

Equistar will use natural gas as pilot fuel to minimize GHG emissions, including emissions of CH4. EPA rules for estimation of GHG emissions from combustion of various fuels can be found at 40 CFR Part 98, Subpart C. In Table C-2, EPA indicates that CH4 emissions from combustion of natural gas are lower than CH4 emissions from combustion of other common fuels. This option is technically feasible.

9.5.2.3 STEP 3 – RANK REMAINING CONTROL OPTIONS BY EFFECTIVENESS

Because all technically feasible controls are being implemented, ranking is unnecessary.

9.5.2.4 STEP 4 – TOP-DOWN EVALUATION OF CONTROL OPTIONS

Because all technically feasible controls are being implemented, further evaluation is unnecessary.

9.5.2.5 STEP 5 – SELECT CH_4 BACT FOR FLARE

Equistar is proposing to use a properly designed and operated flare for control of waste gas emissions. Waste gas flows to the flare from normal unit operations are minimized through unit design. The pilots will be fueled with natural gas. The flare will meet the requirements of 40 CFR §60.18, and will be properly instrumented and controlled.

BACT Table 13: Summary of Flare CH4 Emissions w/ BACT Applied

Source	Description	TPY CH4	TPY CO2e	lb/hr CH4	lb/hr CO2e
EMEOHFLARE	Methanol Flare	0.88	18	76	1,589
EEMERFLARE	Emergency Flare Pilots	<0.01	0.07	<0.01	0.02
17E01	East Plant Flare - Product Loading	<0.01	0.02	<0.01	0.05

9.5.3 FLARE – N2O BACT EVALUATION

Process gas routed to the flares will not contain N_2O. The flares are required to safely dispose of process gas and to meet BACT requirements for criteria pollutant emissions and that process of combustion will generate NOx emissions, including some N_2O. The N_2O emissions generated by the flares have been estimated at approximately 9 pounds per year (1.40 TPY CO2e, or less than 1-millionth of the CO2e of this overall project). The emissions of N_2O generated by the flares are insignificant and there are no known controls for N_2O generated by flares. The most effective means for N_2O control relate to reduction of waste gas flows and use of CH_4 as a fuel.

9.5.3.1 STEP 1 – IDENTIFY AVAILABLE CONTROL OPTIONS

The following potential N_2O control strategies for the flares were considered as part of this BACT analysis:

- ▲ Flare Gas Recovery
- ▲ Waste Gas Minimization
- ▲ Use of Natural Gas for Pilot Fuels

9.5.3.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

9.5.3.2.1 FLARE GAS RECOVERY

Flaring can be reduced by installation of commercially available equipment to construct a recovery system, including recovery compressors, flow controls and piping systems. The recovered gas is then utilized by introducing it into the fuel system to supplement the normally used fuels, or recycled into the process.

This methanol unit has no continuous flows of waste gases to the flares and other flows to the flares are intermittent, consisting of MSS waste gases and upset/emergency flows. Due to the absence of any continuous flow, and the fact that when there will be waste gas flows, they will be highly variable both in rate and composition based on the source, this option is both impractical and infeasible. The primary technical barriers are that any effective flare gas recovery system would need to switch on immediately to capture waste gas, the disposition of the waste gas would need to have sufficient capacitance to accommodate the intermittent and potentially significant gas flow, and the disposition would need to be able to take variability of composition.

9.5.3.2.2 WASTE GAS MINIMIZATION

Waste gas minimization is technically feasible and is incorporated into the design of the unit. As such, certain gas streams that might otherwise be flared are returned to process.

9.5.3.2.3 USE OF NATURAL GAS AS PILOT FUEL

Equistar will use natural gas as pilot fuel to minimize GHG emissions, including emissions of N_2O. EPA rules for estimation of GHG emissions from combustion of various fuels can be found at 40 CFR Part 98, Subpart C. In Table C-2, EPA indicates that N_2O emissions from combustion of natural gas are lower than N_2O emissions from combustion of other common fuels. This option is technically feasible.

9.5.3.3 Step 3 – Rank Remaining Control Options by Effectiveness

Because all technically feasible controls are being implemented, ranking is unnecessary.

9.5.3.4 Step 4 – Top-Down Evaluation of Control Options

Because all technically feasible controls are being implemented, further evaluation is unnecessary.

9.5.3.5 Step 5 – Select N2O BACT for Flare

Equistar is proposing to use a properly designed and operated flare for control of waste gas emissions. Waste gas flows to the flare from normal unit operations are minimized through unit design. The pilots will be fueled with natural gas. The flare will meet the requirements of 40 CFR §60.18, and will be properly instrumented and controlled.

Source	Description	TPY N_2O	TPY CO2e	lb/hr N_2O	lb/hr CO2e
EMEOHFLARE	Methanol Flare	0.01	3.99	0.49	153
EEMERFLARE	Emergency Flare Pilots	<0.01	0.11	<0.01	0.03
17E01	East Plant Flare - Product Loading	<0.01	0.05	<0.01	0.15

9.6 Fugitive Emissions GHG BACT

Greenhouse Gas (GHG) Best Available Control Technology (BACT) for fugitive emissions has been evaluated via a “top-down” five-step approach. Each of those five steps is outlined below. The analysis has been conducted for CH_4, the only CO2e emitted from fugitive sources in any level of significance. CO_2 emissions from fugitive sources account for approximately 1/10,000th of the unit’s total CO2e emissions. The analysis led to the conclusion that BACT for fugitive emissions of CH_4 is leak detection and repair program based on Method 21 monitoring for leaks. Audio, visual and olfactory detection of leaks of CO2 may provide some reduction of CO_2 emissions.

9.6.1 CH4 Fugitive Emissions BACT

9.6.2 Step 1 – Identify All Control Technologies

Summary of Step 1

Equistar has identified five common technologies and practices for control of fugitive emissions of CH_4. All are carried forward to Step 2.

Identification of Control Technologies

In determining whether a technology is available for controlling GHG emissions from fugitive components, permits and permit applications and US. EPA's RBLC were consulted. Based on these resources, the following available control technologies were identified although not specific to GHGs:

- Installation of leakless technology components to eliminate fugitive emission sources.
- Instrumented Leak Detection (Method 21) and Repair (LDAR) Program;
- Leak Detection and Repair Program with Remote Sensing Technology.
- Audio, visual, and olfactory (AVO) detection of leaks followed by repair.
- Design and construct facilities with high quality components, with materials of construction compatible with the process.

9.6.3 STEP 2 – TECHNICAL FEASIBILITY ANALYSIS

Summary of Step 2

All methods identified in Step 1 of the BACT analysis for CH_4 emissions from fugitive emissions sources are determined to be technically feasible, and are all carried forward to Step 3.

9.6.3.1 LEAKLESS TECHNOLOGY

Leakless technology valves are available and in use in industry. In addition, welded connections in lieu of flanged or screwed connection provide leakless operation.

9.6.3.2 INSTRUMENTED LEAK DETECTION (METHOD 21) AND REPAIR PROGRAMS

LDAR programs based on EPA Method 21 leak detection are possible for streams containing combustible gases, including methane. Equistar currently applies this method of LDAR to components in certain VOC services.

9.6.3.3 LEAK DETECTION AND REPAIR PROGRAM WITH REMOTE SENSING TECHNOLOGY.

Remote sensing of leaks has been proven as a technology using sophisticated infrared cameras. The use of such devices has been approved by EPA as an alternative to Method 21 detection in certain instances. The remote sensing technology can detect CH_4 emissions.

9.6.3.4 AUDIO, VISUAL, AND OLFACTORY (AVO) DETECTION OF LEAKS FOLLOWED BY REPAIR

AVO methods of leak detection are technically feasible and some states have approved monitoring and repair credits for emissions estimation where this method of leak detection and repair is employed.

9.6.3.5 DESIGN AND CONSTRUCT FACILITIES WITH HIGH QUALITY COMPONENTS, WITH MATERIALS OF CONSTRUCTION COMPATIBLE WITH THE PROCESS.

This technology to minimize leak frequency and severity is feasible.

9.6.4 STEP 3 – RANKING OF REMAINING CONTROL TECHNOLOGIES BY EFFECTIVENESS

Summary of Step 3

BACT Table 14 provides in order of decreasing effectiveness for control of fugitive emissions of CH_4 the potential technologies to be used.

BACT Table 14: Fugitive Emissions Control Technologies and their Effectiveness

Technology	Control Effectiveness (%)	CH_4 Emissions with Control (lb/hr)	CO2e Emissions with Control (TPY)
Leakless technologies	~100	0.00	0.00
Instrumented Leak Detection and Repair (28LAER)	97	1.09	100.05
Leak Detection & Repair w/ Remote Sensing	>75	9.06	833.75
Audio, Visual, Olfactory	30	25.38	2334.5
Design & Construct w/ High Quality Components	Undetermined	NA	NA

Leakless Technology

Leakless technologies are nearly 100% effective in eliminating leaks except when certain components of the technology suffer from a physical failure. These technologies do not, however, eliminate all leak interfaces, even when working perfectly. Those interfaces are typically stationary interfaces and therefore leak frequency at those interfaces of component parts (e.g., valve body to bonnet) would be expected to be low. The critical elements of leakless components include parts such as a bellows installed on a valve stem, or the diaphragm in a diaphragm valve. Following a failure of one of these parts, the component is most often not repairable online and may leak until the next unit shutdown. Nevertheless, this is the most effective of the controls.

9.6.4.1 INSTRUMENTED LEAK DETECTION (METHOD 21) AND REPAIR PROGRAMS

LDAR programs based on quarterly testing with EPA Method 21 leak detection, and repair of leaks greater than 500 ppm have been given a 97% control credit by some state agencies. Such detection is possible for accessible components in combustible gas service, unless simultaneously emitted noncombustible gases such as nitrogen are in too high of a concentration. The 97% allowed credit makes this the second most effective control.

9.6.4.2 LEAK DETECTION AND REPAIR PROGRAM WITH REMOTE SENSING TECHNOLOGY.

Remote sensing of leaks has been approved by EPA as a partial alternative to Method 21 detection in certain instances. EPAs approved alternate method allows use of remote sensing technology provided components are monitored at least annually using Method 21 for leak detection. Due to equivalency with Method 21 monitoring, is assumed to have no less than 75% control effectiveness.

9.6.4.3 AUDIO, VISUAL, AND OLFACTORY (AVO) DETECTION OF LEAKS FOLLOWED BY REPAIR

AVO methods of leak detection and repair are given credit for emission reduction, however that effectiveness is highly dependent on the system pressure (high pressure systems have higher potential for making noise, or creating a visible emission or condensation/ice at the leak) and on the odor of the leaking material. Effectiveness is also dependent on the frequency of AVO inspection. It is highly unlikely that AVO methods are more effective than EPA alternative procedure listed above for components in methane and fuel gas services that are the subject of this project. Some programs allow 30% control effectiveness for AVO monitoring.

9.6.4.4 DESIGN AND CONSTRUCT FACILITIES WITH HIGH QUALITY COMPONENTS, WITH MATERIALS OF CONSTRUCTION COMPATIBLE WITH THE PROCESS.

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

A control effectiveness of design and construction of facilities with high quality components, and with materials of construction compatible with the process is unknown.

9.6.5 STEP 4 – TOP-DOWN EVALUATION OF CONTROL OPTIONS

Summary of Step 4

Leakless technology is rejected in this step. The subsequent methods for reduction of fugitive emissions of CH4 have been evaluated. All remaining methods are evaluated and determined to provide:

Instrumented LDAR program	97% control
Remote Sensing	75% control
AVO	30% control
Use of High Quality Components	Unknown

9.6.5.1 LEAKLESS TECHNOLOGY

While leakless technologies provide for the highest level of control of the five technologies initially identified, Equistar has determined that leakless technologies are not justified for CH4 service in consideration of the other control technologies to be employed. Leakless technologies have not been universally adopted as LAER, or even BACT. Leakless technologies are not required for toxic or extremely hazardous services for components covered by rules for Hazardous Air Pollutants. Therefore it is reasonable to state that these technologies are unwarranted for control of CH4 with no acute impact. Any further consideration of available leakless technologies for GHG controls is unnecessary.

9.6.5.2 INSTRUMENTED LEAK DETECTION (METHOD 21) AND REPAIR PROGRAMS

LDAR programs for which instrumented detection of leaks is an essential activity have traditionally been developed for control of VOC emissions. BACT determinations related to control of VOC emissions rely on economic reasonableness for these instrumented programs. The adverse impact of non-VOC fugitive emissions of CH_4 due to global warming potential has not been quantified, and no reasonable cost effectiveness has been assigned. Nevertheless, with 97% control effectiveness, and general acceptance for components in VOC service, Equistar proposes to use TCEQ method 28LAER for leak detection and repair.

9.6.5.3 LEAK DETECTION AND REPAIR PROGRAM WITH REMOTE SENSING TECHNOLOGY.

Remote sensing of fugitive components in CH4 service can provide an effective means to identify leaks. However, because the 28LAER program will be adopted for control of fugitive CH4 emissions, this option is rejected. The control effectiveness for CH4 emissions would be expected to be greater than 75% due to annual instrumented monitoring associated with the remote sensing program and an alternate means of control.

9.6.5.4 AUDIO, VISUAL, AND OLFACTORY (AVO) DETECTION OF LEAKS FOLLOWED BY REPAIR

Leaking components can be identified through AVO methods. However, because the 28LAER program will be adopted for control of fugitive CH_4 emissions, this option is rejected. The effectiveness associated with this method is typically 30%.

9.6.5.5 DESIGN AND CONSTRUCT FACILITIES WITH HIGH QUALITY COMPONENTS, WITH MATERIALS OF CONSTRUCTION COMPATIBLE WITH THE PROCESS.

This method for control of fugitive emissions of CH_4 will be employed in the unit although the effectiveness is not known. Because there is not a method for demonstration of compliance with this option, it is not carried forward as BACT.

9.6.6 STEP 5 – SELECT CH_4 BACT FOR FUGITIVE EMISSIONS

Equistar proposes to employ TCEQ's 28LAER leak detection and repair to components in CH_4 service.

Technology	Control Effectiveness (%)	CH_4 Emissions with Control (lb/hr)	CO2e Emissions with Control (lb/hr)
Instrumented LDAR (28LAER)	97	1.09	100.05

9.7 CO_2 FUGITIVE EMISSIONS BACT

9.7.1 STEP 1 – IDENTIFY ALL CONTROL TECHNOLOGIES

Summary of Step 1

Equistar has identified three common technologies and practices for control of fugitive emissions of CO_2. All are carried forward to Step 2.

Identification of Control Technologies

In determining whether a technology is available for controlling GHG emissions from fugitive components, permits and permit applications and US. EPA's RBLC were consulted. Based on these resources, the following available control technologies were identified although not specific to GHGs:

- ▲ Installation of leakless technology components to eliminate fugitive emission sources.

- Audio, visual, and olfactory (AVO) detection of leaks followed by repair.
- Design and construct facilities with high quality components, with materials of construction compatible with the process.

9.7.2 STEP 2 – TECHNICAL FEASIBILITY ANALYSIS

Summary of Step 2

All methods identified in Step 1 of the BACT analysis for CO_2 emissions from fugitive emissions sources are determined to be technically feasible, and are all carried forward to Step 3.

9.7.2.1 LEAKLESS TECHNOLOGY

Leakless technology valves are available and in use in industry. In addition, welded connections in lieu of flanged or screwed connection provide leakless operation.

9.7.2.2 AUDIO, VISUAL, AND OLFACTORY (AVO) DETECTION OF LEAKS FOLLOWED BY REPAIR

AVO methods of leak detection are technically feasible and some states have approved monitoring and repair credits for emissions estimation where this method of leak detection and repair is employed. However, the effectiveness for CO_2 emissions identification has not been determined.

9.7.2.3 DESIGN AND CONSTRUCT FACILITIES WITH HIGH QUALITY COMPONENTS, WITH MATERIALS OF CONSTRUCTION COMPATIBLE WITH THE PROCESS.

This technology to minimize leak frequency and severity is feasible.

9.7.3 STEP 3 – RANKING OF REMAINING CONTROL TECHNOLOGIES BY EFFECTIVENESS

SUMMARY OF STEP 3

The following table provides in order of decreasing effectiveness for control of fugitive emissions of CH_4 the potential technologies to be used.

Leakless technologies are assumed to be 100% effective for control of fugitive emissions. An audio, visual and olfactory program is assigned a 30% effectiveness, and the use of high quality components in not quantified.

9.7.3.1 LEAKLESS TECHNOLOGY

Leakless technologies are nearly 100% effective in eliminating leaks except when certain components of the technology suffer from a physical failure. These technologies do not, however, eliminate all leak interfaces, even when working perfectly. Those interfaces are typically stationary interfaces and therefore leak frequency at those interfaces of component parts (e.g., valve body to bonnet) would be expected to be low. The critical elements of leakless components include parts such as a bellows installed on a valve stem, or the diaphragm in a diaphragm valve. Following a failure of one of these parts, the component is most often not repairable online and may leak until the next unit shutdown. Nevertheless, this is the most effective of the controls.

9.7.3.2 AUDIO, VISUAL, AND OLFACTORY (AVO) DETECTION OF LEAKS FOLLOWED BY REPAIR

AVO methods of leak detection and repair of hydrocarbon emissions are given credit for emission reduction, however that effectiveness is highly dependent on the system pressure (high pressure systems have higher potential for making noise, or creating a visible emission or condensation/ice at the leak) and on the odor of the leaking material. Effectiveness is also dependent on the frequency of AVO inspection. Some programs allow 30% control effectiveness for AVO monitoring and this estimated control effectiveness is applied in the analysis in absence of any better data.

9.7.3.3 DESIGN AND CONSTRUCT FACILITIES WITH HIGH QUALITY COMPONENTS, WITH MATERIALS OF CONSTRUCTION COMPATIBLE WITH THE PROCESS.

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

A control effectiveness of design and construction of facilities with high quality components, and with materials of construction compatible with the process is unknown.

9.7.4 STEP 4 – TOP-DOWN EVALUATION OF CONTROL OPTIONS

Summary of Step 4

Leakless technology is rejected in this step. The two subsequent methods for reduction of fugitive emissions of CO_2 have been evaluated and include:

AVO	30% control
Use of High Quality Components	Unknown

9.7.4.1 LEAKLESS TECHNOLOGY

While leakless technologies provide for the highest level of control of the three technologies initially identified, Equistar has determined that leakless technologies are not justified for CO_2 service in consideration of the other control technologies to be employed. Leakless technologies have not been universally adopted as LAER, or even BACT. Leakless technologies are not required for toxic or extremely hazardous services for components covered by rules for Hazardous Air Pollutants. Therefore it is reasonable to state that these technologies are unwarranted for control of CO_2 with no acute impact. Any further consideration of available leakless technologies for GHG controls is unnecessary.

9.7.4.2 AUDIO, VISUAL, AND OLFACTORY (AVO) DETECTION OF LEAKS FOLLOWED BY REPAIR

In certain circumstances leaking components can be identified through AVO methods. Effectiveness associated with this method is typically 30%. Such a program is often incorporated into operating technician rounds.

9.7.4.3 DESIGN AND CONSTRUCT FACILITIES WITH HIGH QUALITY COMPONENTS, WITH MATERIALS OF CONSTRUCTION COMPATIBLE WITH THE PROCESS.

This method for control of fugitive emissions of CO_2 will be employed in the unit although the effectiveness is not known. Because there is not a method for demonstration of compliance with this option, it is not carried forward as BACT.

9.7.5 STEP 5 – SELECT CH_4 BACT FOR FUGITIVE EMISSIONS

Equistar proposes to employ AVO methods for leak detection and repair to components in CO_2 service. It is proposed that this method be incorporated in operator rounds.

Technology	Control Effectiveness (%)	CO_2 Emissions with Control (lb/hr)	CO2e Emissions with Control (TPY)
AVO for CO2 components	30	8.90	38.97

10 MATERIAL BALANCE

TABLE 2
MATERIAL BALANCE

MeOH Restart, Permit No. 8125

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

LIST EVERY MATERIAL INVOLVED IN EACH OF THE FOLLOWING GROUPS	Point No. from Flow Diagram	Process Rate (lbs/hr or SCFM) standard conditions: 70°F, 14.7 psia. Check appropriate column at right for each process.		Measurement	Estimation	Calculation
1. Raw Materials – Input						
Light Hydrocarbon	1	126,163	lb/hr			X
Hydrogen	1	8,250	lb/hr			X
Water	1	412,020	lb/hr			X
2. Fuels - Input						
Fuel Gas	2	3,188	SCFM			
Recycle Purge Gas	2	51,913	SCFM			
3. Products & By-Products - Output						
Methanol	3	258,275	lb/hr			X
4. Solid Wastes - Output						
5. Liquid Wastes - Output						
Wastewater	4	50,040	lb/hr			
6. Airborne Waste (Solid) - Output						
7. Airborne Wastes (Gaseous) - Output See Table 1(a)	5	See Table 1(a)				X

APPENDIX A

EMISSION CALCULATIONS

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - Page 1

Date	June 2012	**Permit No.:**	8125	**Regulated Entity No.:**	100542281
Area Name:	Equistar Chemicals LP, Channelview Facility, Methanol Restart			**Customer Reference No.:**	600124705

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

AIR CONTAMINANT DATA

1. Emission Point			**2. Component of Air Contaminant Name**	**3. Air Contaminant Emission Rate**			
(A) EPN	**(B) FIN**	**(C) NAME**		**Maximum Emission Rate (lb/hr)**	**CO_2e Maximum Emission Rate (lb/hr)**	**CO_2e MTCE/yr (A)**	**CO_2e ton/yr (B)**
EHTF7001	HTF7001	Reformer Furnace	CO_2e	188,906.62	188,906.62	750,836	827,411
			CO_2	188,721.46	188,721.46	750,100	826,600
			N_2O	0.36	110.34	439	483
			CH_4	3.56	74.75	297	327
EMEOHFLARE	MEOHFLARE	Methanol Flare	CO_2e	146,724.44	146,724.44	3,412	3,755
			CO_2	144,943.08	144,943.08	3,391	3,733
			N_2O	0.59	182.77	4	4
			CH_4	76.12	1,598.59	16	18
EEMERFLARE	EMERFLAREP	Methanol Emergency Flare Pilots	CO_2e	41.36	41.36	164	181
			CO_2	41.32	41.32	164	181
			N_2O	0.00	0.02	0	0
			CH_4	0.00	0.02	0	0
17E01	17FL1701, 17FL1701F, 17FL1701P	East Plant Flare - Product Loading	CO_2e	51.45	51.45	36	39
			CO_2	51.45	51.45	36	39
			N_2O	0.00	0.15	0	0
			CH_4	0.00	0.05	0	0
EFUGMEOH	FUGMEOH	Equipment Fugitives	CO_2e	31.74	31.74	126	139
			CO_2	8.90	8.90	35	39
			N_2O	0.00	0.00	0	0
			CH_4	1.09	22.84	91	100

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - Page 2

Date	June 2012	**Permit No.:**	8125	**Regulated Entity No.:**	100542281
Area Name:	Equistar Chemicals LP, Channelview Facility, Methanol Restart			**Customer Reference No.:**	600124705

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

AIR CONTAMINANT DATA			**EMISSION POINT DISCHARGE PARAMETERS**										
1. Emission Point			**4. UTM Coordinates of Emission**			**5. Building Height (Feet)**	**6. Height Above Ground (Feet)**	**7. Stack Exit Data**			**8. Fugitives**		
(A) EPN	**(B) FIN**	**(C) NAME**	**Zone**	**East (Meters)**	**North (Meters)**			**(A) Diameter (Feet)**	**(B) Velocity (fps)**	**(C) Temperature (ºF)**	**(A) Length (Ft)**	**(B) Width (Ft)**	**(C) Axis Degrees**
EHTF7001	HTF7001	Reformer Furnace	15	295,190	3,302,020		121	14	46.3	400			
EMEOHFLARE	MEOHFLARE	Methanol Flare	15	295,366	3,301,516		190	1					
EEMERFLARE	EMERFLAREP	Methanol Emergency Flare	15	295,366	3,301,516		190	3					
17E01	17FL1701F, 17FL1701P	East Plant Flare (MeOH Loading to Flare)	15	296,251	3,301,800		225	3.5	65.6	1832			
EFUGMEOH	FUGMEOH	Equipment Fugitives	15	295,245	3,302,010						600	375	90

EPN = Emission Point Number
FIN = Facility Identification Number

Equistar Chemicals, LP
Channelview North Facility
Methanol Restart **Jun-12**
NSR Permit No. 8125

GHG Emission Summary

EPN	Description	CO_2e MTCE/yr	CO_2e short tons/yr
EHTF7001	Reformer Furnace	750,836	827,411
EMEOHFLARE	Methanol Flare	3,412	3,755
EEMERFLARE	Methanol Emergency Flare	164	181
17E01	East Plant Flare (MeOH Loading to Flare)	36	39
EFUGMEOH	Equipment Fugitives	126	139
Total Emissions (rounded) =		**754,574**	**831,526**

Equistar Chemicals, LP
Channelview North Facility
Methanol Restar Feb-12
NSR Permit No. 8125

EPN: EHTF7001 (Reformer Furnace)
FIN: HTF7001

GHG Emission Factors - Natural Gas Combustion

Greenhouse Gas	Global Warming Potential[1]	Emission Factor [2] (kg/MMBtu)
CO_2	1	53.02
CH_4	21	1.0E-03
N_2O	310	1.0E-04

[1] Per 40 CFR Part 98 dated July 12, 2010, Table A-1 of Subpart A - *Global Warming Potentials (100-year time horizon)* ; used to convert emissions of each GHG to a CO_2 equivalent basis.

[2] Per 40 CFR Part 98 dated December 17, 2010, Table C-1 of Subpart C - *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel* and Table C-2 of Subpart C - *Default CH_4 and N_2O Emission Factors for Various Types of Fuel* . Emission factors for natural gas (unspecified heat value, weighted U.S. average) are used.

GHG Emission Rates from Natural Gas Combustion

Heat Input Capacity	Maximum Annual Operation	CO_2e from CO_2 Emissions[1]		CO_2e from CH_4 Emissions[1]		CO_2e from N_2O Emissions[1]		Total CO_2e Emissions		
(MMBtu/hr)	(hr/yr)	(MTCE/yr)	(tpy)	(MTCE/yr)	(tpy)	(MTCE/yr)	(tpy)	(lbs/hr)	(MTCE/yr)	(tpy)
1,615	8,760	750,100	826,600	297	327	439	483	**188,907**	**750,836**	**827,411**

[1] Sample Calculation for CO_2 emissions:

CO_2e Emission Rate (MTCE/yr) = (Emission Factor [kg/mmBtu])*(Heat Input Capacity [MMBtu/hr])*(Maximum Annual Operation [hr/yr])*(0.001 tonne/kg)

$$CO_2 \text{ Emission Rate (MTCE/yr)} = \frac{53.02\text{ kg}}{\text{MMBtu}} \cdot \frac{1615\text{ MMBtu}}{\text{hr}} \cdot \frac{8760\text{ hr}}{\text{yr}} \cdot \frac{0.001\text{ tonne}}{1\text{ kg}}$$

= 750,100 MTCE CO2e/yr

Annual Operation [hr/yr])*(0.001 tonne/kg)

CO2 Emission Rate (tpy) = (CO2 Emission Rate [MTCE/yr])*(1.102 ton/tonne)

$$\text{CO2 Emission Rate (tpy)} = \frac{750{,}100\text{ MTCE}}{\text{yr}} \cdot \frac{1.102\text{ ton}}{\text{tonne}}$$

= 826,600 tons CO2e/yr

Equistar Chemicals, LP
Channelview North Facility
Methanol Line Restart Jun-12
NSR Permit No. 8125

EPN: EMEOHFLARE (Methanol Flare)
FIN: MEOHFLARE

NATURAL GAS TO FLARE PILOTS

Calculation Basis		
Natural Gas to Pilot Flowrate[1]	336	scf/hr
Higher Heating Value	1,050	Btu/scf
Molecular Weights		
CO_2	44	lb/lb-mol
CH_4	16	lb/lb-mol
N_2O	44	lb/lb-mol
Global Warming Potential[3]:		
CO_2	1	
CH_4	21	
N2O	310	

[1] Flowrate based on 4 pilots with 1.4 scfm per pilot.

GHG Emission Factors - Natural Gas Combustion

Greenhouse Gas	Emission Factor [1] (kg/MMBtu)
CO_2	53.02
CH_4	1.0E-03
N_2O	1.0E-04

[1] Per 40 CFR Part 98 dated December 17, 2010, Table C-1 of Subpart C - *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel* and Table C-2 of Subpart C - *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*. Emission factors for

GHG Emission Rates from Supplemental Natural Gas Combustion in the Flare

Heat Input Capacity[1]	CO_2e from CO_2 Emissions[3]		CO_2e from CH_4 Emissions[3]		CO_2e from N_2O Emissions[3]		Total CO_2e Emissions		
(MMBtu/hr)	(MTCE/yr)[2]	(tpy)	(MTCE/yr)[2]	(tpy)	(MTCE/yr)[2]	(tpy)	(lb/hr)	(MTCE/yr)	(tpy)
0.35	164.00	181.00	0.06	0.07	0.10	0.11	41	164	181

[1] Heat Input Capacity = (Annual Natural Gas Flowrate [scf/hr])*(Higher Heating Value [Btu/scf])/(10^6 Btu/MMBtu)

[2] Sample Calculation for CO_2 emissions (Assume continuous operation of supplemental natrual gas flow - 8,760 hr/yr):

[3] CO_2e Emission Rate (CO_2e/yr) = (Emission Factor [kg/MMBtu]) * (Global Warming Potenial) * (Heat Input Capacity [MMBtu/hr]) * (8,760 hrs/yr) * (1 tonne/ 1000 kg)

[3] CO_2e Emission Rate (tpy) = (CO_2 Emission Rate [CO_2e/yr]) * (1.102 tons / 1 tonne)

Example Calculations

Heat Input Capacity

Heat Input Capacity = (Annual Natural Gas Flowrate [scf/hr])*(Higher Heating Value [Btu/scf])/(106 Btu/MMBtu)
Heat Input Capacity = 336 scfh * 1050 Btu/scf * 1,000,000 Btu / 1 MMBtu
Heat Input Capacity = 0.35 MMBtu/hr

CO2e Emission Rate from CH4 Emissions

CO_2 Emission Rate (CO_2e/yr) = (Emission Factor [kg/MMBtu]) * (Global Warming Potenial) * (Heat Input Capacity [MMBtu/hr]) * (8,760 hrs/yr) * (1 tonne/ 1000 kg)
CO2 Emission Rate (CO_2e/yr) = 1.0E-03 kg/MMBtu * 21 * 0.35 MMBtu/hr * 8760 hrs/yr * 1 tonne/1000 kg * 1.102 ton/tonne
CO2 Emission Rate (CO_2e/yr) = 0.07 tpy CO_2e from CH4

Equistar Chemicals, LP
Channelview North Facility
Methanol Restart Jun-12
NSR Permit No. 8125

EPN: 17E01 (East Plant Flare - Product Loading)
FIN: 17FL1701, 17FL1701F, 17FL1701P

Calculation Basis		
Factors	**Units**	**Methanol**
Vapor Pressure	psia	4.86
Vapor Molecular Weight	lb/lb-mol	32.04
Liquid Temperature	°R	560
Loading Method	---	Submerged-dedicated
Maximum Hourly Loading Rate	gal/hr	18,000
Annual Loading Rate	gal/yr	66,666,667
Gross Heat Content	Btu/lb	9,838
Global Warming Potential:		
CO_2		1
Chiller in Service	days/yr	335
Chiller Out of Service	days/yr	30

Loading Loss Factor Calculation

Factors	Units	Methanol
Saturation Factor[1]	--	0.60
Loading Loss[2]	lb/Mgal	2.08

[1] Obtained from EPA AP-42, Section 5.2 (6/08), Table 5.2-1 for submerged dedicated loading.

[2] Calculation based on AP-42, Section 5.2.2.1.1 (6/08) Loading Equation. Loading Loss = (12.46)*(Saturation Factor)*(Vapor Pressure [psia])*(Vapor Molecular Weight [lb/lb-mol])/(Liquid Temperature [°R]).

Combustion Emissions

Component	VOC Vapors Sent to Flare[1, 2]		Molecular Weight of Component	No. of Carbon Atoms	Carbon Weight	Chiller Recovery Efficiency	Flare Destruction Efficiency[3]	CO_2e from CO_2[4]		
								Hourly[5]	Annual[6]	
	(lb/hr)	(lb/yr)	(lb/lbmol)		(%)	(%)	(%)	(lb/hr)	(MTCE/yr)	(tpy)
CH_3OH	3.74	12,719.52	32	1	38%	90%	99%	5.14	18.77	20.68
CH_3OH (Chiller out of service)	37.42	11,390.62	32	1	38%	0%	99%	51.45	16.81	18.52
							Total Emissions =	**56.79**	**35.65**	**39.27**

[1] This option reflects the loading vent being routed to a chiller with 90% recovery and the uncondensed methanol being routed to the flare. In addition, the hourly and annual numbers will allow for the chiller being out of service for 30 days per year.

[2] VOC Vapors Sent to Flare (lb/hr) = (Loading Loss [lb/Mgal]) * (1/10^3[Mgal/gal]) * (1 - Chiller Recovery Efficiency [%]).

VOC Vapors Sent to Flare (lb/yr) = (Loading Loss [lb/Mgal]) * (1/10^3[Mgal/gal]) * (Annual Loading Rate [gal/hr]) * (1 - Chiller Recovery Efficiency [%]) * (Chiller in Service [days/yr])/(365 days/yr)

[3] TCEQ Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers (October 2000), Table 4.

[4] Assume that all carbon from components in waste gas stream is converted to carbon dioxide.

[5] CO_2 Hourly Emissions (lb/hr) = (VOC Vapors Sent to Flare [lb/hr])* Wt% of Carbon*(Molecular Weight of CO_2 [lb/lbmol])/(Molecular Weight of C [lb/lbmol])

[6] CO_2 Annual Emissions (tpy) = CO_2 Hourly Emissions [lb/hr] * (24 hr/day) * (Days/Year) * (ton/2,000 lb) (Global Warming Potential)

CO_2 Emission Rate (CO_2e/yr) = (Emission Rate [tpy]) * (1 tonne / 1.102 tons)

Note: MW of CO_2 = 44, MW of Carbon = 12, to convert mass of Carbon to mass of CO_2 use the MW ratio 44/12.

Example Calculations

VOC Loading Loss Calculation

Calculation based on AP-42, Section 5.2.2.1.1 (6/08) Loading Equation. Loading Loss = (12.46)*(Saturation Factor)*(Vapor Pressure [psia])*(Vapor Molecular Weight [lb/lb-mol])/(Liquid Temperature [°R]).
= (12.46 * 0.6 * 4.86 psia * 32.04 lb/lb-mol) / 560°R
= 2.08 lb/MMgal

VOC Short Term Loading Emission Rate - Chiller in Service
= Loading Loss (lb/Mgal) * 1 Mgal/1,000 gal * Loading Rate (gal/hr) * (1- Chiller % Efficiency) * (1 – Flare DRE %)
= 2.08 lb/Mgal * 1 Mgal / 1,000 gal * 18,000 gal/hr * (1- 90%) * (1 – 99%)
= 3.74 lb/hr

VOC Short Term Loading Emission Rate - Chiller Out of Service
= Loading Loss (lb/Mgal) * 1 Mgal/1,000 gal * Loading Rate (gal/hr) * (1 – Flare DRE %)
= 2.08 lb/Mgal * 1 Mgal / 1,000 gal * 18,000 gal/hr * (1 – 99%)
= 37.42 lb/hr

GHG Emission Factors - Petroleum Combustion

Greenhouse Gas	Emission Factor[1]	Global Warming Potential[2]
	(kg/MMBtu)	
CH_4	3.0E-03	21
N_2O	6.0E-04	310

[1] Per 40 CFR Part 98 dated December 17, 2010, Table C-1 of Subpart C -*Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel* and Table C-2 of Subpart C -*Default*

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

Combustion Emissions (CO2e converted from CH4 & N2O)

Component	Maximum Hourly Combusted Material[2]		Annual Combusted Material[2]		Chiller Recovery Efficiency	Flare Destruction Efficiency[3]	CO2e from CH4 [2]	CO2e from CH4 [2]	CO2e from N2O [2]	CO2e from N2O [2]	CO_2e Total (Combusion of Organics)[2]	
	(lb/hr)	(Btu/hr) [1]			(%)	(%)	lb/hr	tpy	lb/hr	tpy	(lb/hr)	(tpy)
CH3OH	3.74	36,812	12,720	125,134,639	90%	99%	0.01	0.01	0.01	0.03	**0.02**	**0.03**
CH3OH (Chiller out of service)	37.42	368,120	11,391	112,060,871	0%	99%	0.05	0.01	0.15	0.02	**0.20**	**0.03**
						TOTAL	0.05	0.02	0.15	0.05	**0.20**	**0.06**

[1] Heat Input Capacity = (Vent rate [lb/hr])*(Higher Heating Value [Btu/lb])

[2] Sample Calculation for CO_2 emissions

CO_2 Emission Rate (CO_2e lb/hr) = (Emission Factor [kg/MMBtu]) * 2.2 lb/kg * (Global Warming Potenial) * (Heat Input Capacity [MMBtu/hr]) /(10^6 Btu/MMBtu) * (1 - Condenser Recovery Efficiency) * (Flare DRE)

CO_2 Emission Rate (CO_2e tpy) = CO2e (lb/hr) * duration (hrs/yr) / 2000 lb/ton

Equistar Chemicals, LP
Channelview North Facility
Methanol Line Restart Jun-12
NSR Permit No. 8125
Pilots, Flare Header Sweep & Supplemental Natural Gas

EPN: EMEOHFLARE (Methanol Flare)
FIN: MEOHFLARE

Annual Natural Gas Flowrate (	4,109	scf/hr
Higher Heating Value	1,050	Btu/scf

GHG Emission Factors - Natural Gas Combustion

Greenhouse Gas	Emission Factor [1] (kg/MMBtu)
CO_2	53.02
CH_4	1.0E-03
N_2O	1.0E-04

[1] Per 40 CFR Part 98 dated December 17, 2010, Table C-1 of Subpart C - *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel* and Table C-2 of Subpart C - *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*. Emission factors for natural gas (unspecified heat value, weighted U.S. average) are used.

GHG Emission Rates from Supplemental Natural Gas Combustion in the Flare

Heat Input Capacity[1]	CO_2e from CO_2 Emissions[3]		CO_2e from CH_4 Emissions[3]		CO_2e from N_2O Emissions[3]		Total CO_2e Emissions		
(MMBtu/hr)	(MTCE/yr)[2]	(tpy)	(MTCE/yr)[2]	(tpy)	(MTCE/yr)[2]	(tpy)	(lb/hr)	(MTCE/yr)	(tpy)
4.31	2,000	2,200	0.79	0.88	1.17	1.29	503	2,002	2,202

[1] Heat Input Capacity = (Annual Natural Gas Flowrate [scf/hr])*(Higher Heating Value [Btu/scf])/(10^6 Btu/MMBtu)

[2] Sample Calculation for CO_2 emissions (Assume continuous operation of supplemental natrual gas flow - 8,760 hr/yr):

[3] CO_2 Emission Rate (CO_2e/yr) = (Emission Factor [kg/MMBtu]) * (Global Warming Potenial) * (Heat Input Capacity [MMBtu/hr]) * (8,760 hrs/yr) * (1 tonne/ 1000 kg)

[3] CO_2 Emission Rate (tpy) = (CO_2 Emission Rate [CO_2e/yr]) * (1.102 tons / 1 tonne)

Example Calculations

Heat Input Capacity

Heat Input Capacity = (Annual Natural Gas Flowrate [scf/hr])*(Higher Heating Value [Btu/scf])/(106 Btu/MMBtu)
Heat Input Capacity = 4109 scfh * 1050 Btu/scf * 1,000,000 Btu / 1 MMBtu
Heat Input Capacity = 4.31 MMBtu/hr

CO2e Emission Rate from CH4 Emissions

CO_2 Emission Rate (CO_2e/yr) = (Emission Factor [kg/MMBtu]) * (Global Warming Potenial) * (Heat Input Capacity [MMBtu/hr]) * (8,760 hrs/yr) * (1 tonne/ 1000 kg)
CO2 Emission Rate (CO_2e/yr) = 1.0E-03 kg/MMBtu * 21 * 4.31 MMBtu/hr * 8760 hrs/yr * 1 tonne/1000 kg * 1.102 ton/tonne
CO2 Emission Rate (CO_2e/yr) = 0.88 tpy CO_2e from CH4

Summary of Other Sources Contributing GHG Emissions to the Methanol Flare		Total CO_2e Emissions		
		(lb/hr)	(MTCE/yr)	(tpy)
Methanol Flare		503	2,002	2,202
MSS Emissions SD & Clearing		3,572	39	43
MSS Reformer Startup		135,989	1,186	1,306
MSS Column Startup		10,233	186	204
TOTAL EMISSIONS =		**150,297**	**3,412**	**3,755**

Equistar Chemicals, LP
Channelview North Facility, TX
Methanol Restart Jun-12
NSR Permit No. 8125
MSS Shutdown & Clearing

EPN: EMEOHFLARE (Methanol Flare)
FIN: MEOHFLARE

Calculation Basis		
Factor	**Methanol**	**Units**
VOC Vapor Pressure	0.15	psia
Vapor Molecular Weight	16.6	lb/lb-mol
Gas Constant	10.73	psia*ft^3/lb-mol*°R
Maximum Temperature	560	°R
Molecular Density	359.10	ft^3/lb-mol
Heat Content	15,743	Btu/lb
Avg System Pressure by Mass Frac	46.06	psig
Degassing Saturation Factor	1.0	
Duration of Clean-out[2]	24	hr
Stream Composition		
CH_4	29.9%	Wt%
CO	8.0%	Wt%
CO_2	6.4%	Wt%
H_2	4.3%	Wt%
MeOH	47.6%	Wt%
Other VOC	3.8%	Wt%
Gross Heat Value		
CH_4	24,193	Btu/lb
CO	4,344	Btu/lb
CO_2	0	Btu/lb
H_2	61,517	Btu/lb
MeOH	9,838	Btu/lb
Other VOC	22,198	Btu/lb
Global Warming Potential[3]		
CH4	21	
CO_2	1	

[2] Based on a conservative estimate of 24 hours turnaround time.

[3] Per 40 CFR Part 98 dated July 12, 2010, Table A-1 of Subpart A - *Global Warming Potentials (100-year time horizon)* ; used to convert emissions of each GHG to a CO_2 equivalent basis.

Process Equipment Turnaround Emissions to Flare

Equipment Volume[1]	Flare DRE	Vent Rate to Flare[2]	
(ft^3)	%	(lb/hr)	(lb/yr)
323,304.4	98%	1951.08	46,825.98

[1] Equipment volume represents volume of vessels, towers and piping. (Added 20% to equipment volume for piping)

[2] Vent Rate to Flare (lb/hr) = (Equipment Volume [ft^3])/(Molecular Density [ft^3/lb-mol])*(Vapor Molecular Weight [lb/lb-mol])/(Duration of Clean-out [hr])*(System Pressure [psig]/Atmospheric Pressure [psig])
Vent Rate to Flare (tpy) = (VOC Vent Rate to Flare [lb/hr])*(Duration of Clean-out [hr])

Example Calculation

Vent Rate to Flare (lb/hr) = (323,304.4 ft^3 / 359.1 ft3/lb-mol) * (16.6 lb/lb-mol) / (24 hr) * (46.06 psig / 14.7 psig)

Vent Rate to Flare (lb/hr) = 1951.08 lb/hr

Un-combusted Material Emissions (Quantites Passing Through Flare)

Component	Vent to Flare[1,2]		Flare DRE[3]	Global Warming Potential	CO2e Emission Rates from Corresponding GHG Pollutants[4]		
	(lb/hr)	(wt%)	(%)		(lb/hr)	(MTCE/yr)	(tpy)
CH_4	583.37	29.9%	99%	21	122.51	1.33	1.47
CO	156.09	8.0%	98%	--	--	--	--
CO_2	124.87	6.4%	0%	1	124.87	1.36	1.50
H_2	83.90	4.3%	99%	--	--	--	--
MeOH	928.72	47.6%	99%	--	--	--	--
Other VOC	74.14	3.8%	99%	--	--	--	--
				Sub-Total Emissions =	**247.38**	**2.69**	**2.97**

[1] Vent to Flare (lb/hr) = (Vent to Flare [lb/hr]) * (Weight Percent [%])

[2] *TCEQ Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers* (October 2000), Table 4.

[3] Emission Rate (lb/hr) = (Vent to Flare [lb/hr]) * (1-Flare DRE [%]) * (Global Warming Potential)

[4] Annual Emission Rate (tpy) = (Emission Rate [lb/hr])*(Annual Venting Basis [day/yr])*(24 hr/day)/(2000 lb/ton)

Combustion Emissions (Carbon Materials Converted to CO_2)

Component	Combusted Material[1]		Molecular Weight	No. of Carbon Atoms	Carbon Weight	CO_2e from CO_2 (Combusion of Organics)[3,4]		
	(lb/hr)	(Btu/hr) [2]	(lb/lbmol)		(%)	(lb/hr)	(MTCE/yr)	(tpy)
CH_4	577.54	13,972,423	16	1	75%	1,588.23	17.29	19.06
CO	152.96	664,479	28	1	43%	240.37	2.62	2.88
CO_2	--	--	--	--	--	--	--	--
H_2	83.06	5,109,453	2	0	0%	--	--	--
MeOH	919.43	9,045,333	32	1	38%	1,264.21	13.77	15.17
Other VOC	73.40	1,629,327	30	2	80%	215.31	2.34	2.58
					Sub-Total Emissions =	**3,308.13**	**36.02**	**39.70**
					TOTAL EMISSIONS =	**3,572**	**39**	**43**

[1] Combusted Material (lb/hr) = (Vent to Flare [lb/hr])*(Flare DRE [wt%])

[2] Combusted Material (Btu/hr) = (Combusted Material [lb/hr])*(Gross Heating Value [Btu/lb])

[3] Assume that all carbon from components in waste gas stream is converted to carbon dioxide.

[4] CO_2e Hourly Emissions (lb/hr) = (Combusted Material [lb/hr]) * Wt% of Carbon * (Molecular Weight of CO2 [lb/lbmol]) / (Molecular Weight of C [lb/lbmol]) * Global Warming Potential
Annual CO_2e Emissions (tpy) = (CO_2e Emission Rate [lb/hr]) * (Duration of Clean Out [hr]) / (2000 lbs/ton)
Annual CO_2e (MTCE/yr) = Annual CO_2e (tpy) * (1 tonne /1.102 ton).

Note: MW of CO_2 = 44, MW of Carbon = 12, to convert mass of Carbon to mass of CO_2 use the MW ratio 44/12.

Equistar Chemicals, LP
Channelview North Facility, TX
Methanol Restart Jun-12
NSR Permit No. 8125
MSS Shutdown & Clearing

EPN: EMEOHFLARE (Methanol Flare)
FIN: MEOHFLARE

GHG Emission Factors - Petroleum Combustion

Greenhouse Gas	Emission Factor [1] (kg/MMBtu)	Global Warming Potential [2]
CH_4	3.0E-03	21
N_2O	6.0E-04	310

[1] Per 40 CFR Part 98 dated December 17, 2010, Table C-1 of Subpart C - *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel* and Table C-2 of Subpart C - *Default CH_4 and N_2O Emission Factors for Various Types of Fuel* . Emission factors for natural gas (unspecified heat value, weighted U.S. average) are used.

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

Combustion Emissions (CO2e converted from CH4 & N2O)

Component	Combusted Material		CO2e from CH4 [2]	CO2e from N2O [2]	CO_2e Total (Combusion of Organics)[2]	
	(lb/hr)	(Btu/hr) [1]	lb/hr	lb/hr	(lb/hr)	(tpy)
CH_4	577.54	13,972,423	1.94	5.72	7.65	0.09
CO	152.96	664,479	0.09	0.27	0.36	0.00
CO_2	--	--	--	--	--	--
H_2	83.06	5,109,453	0.71	2.09	2.80	0.03
MeOH	919.43	9,045,333	1.25	3.70	4.96	0.06
Other VOC	73.40	1,629,327	0.23	0.67	0.89	0.01
				Sub-Total Emissions =	**16.66**	**0.20**

[1] Heat Input Capacity = (Vent rate [lb/hr])*(Higher Heating Value [Btu/lb])

[2] Sample Calculation for CO_2 emissions

CO_2 Emission Rate (CO_2e lb/hr) = (Emission Factor [kg/MMBtu]) * 2.2 lb/kg * (Global Warming Potenial) * (Heat Input Capacity [MMBtu/hr]) /(10^6 Btu/MMBtu) *

CO_2 Emission Rate (CO_2e tpy) = CO2e (lb/hr) * duration (hrs/yr) / 2000 lb/ton

Equistar Chemicals, LP
Channelview North Facility, TX
Methanol Restart Jun-12
NSR Permit No. 8125
Reformer Startup
EPN: EMEOHFLARE (Methanol Flare)
FIN: MEOHFLARE

Calculation Basis[1]		
Annual Venting Basis	2	events/yr
Normal Vent Rate[2]	90,614	lb/hr
Duration[3]	12	hrs per event
Maximum Vent Rate[4]	113,268	lb/hr
Vent Gas Composition:		
H_2	14.8	wt%
CO	41.0	wt%
CH_4	6.5	wt%
CO_2	37.8	wt%
Higher Heating Value:		
H_2	61,517	Btu/lb
CO	4,344	Btu/lb
CH_4	24,193	Btu/lb
CO_2	0	Btu/lb
Waste Stream Heating Value[5]	12,418	Btu/lb
Global Warming Potential[6]		
CH_4	21	kg CO_2e/kg component
CO_2	1	kg CO_2e/kg component

[1] Data provided by Mr. Darren Gaspard (Equistar Chemicals, LP) to Ms. Melissa Dakas (Trinity Consultants) via email on October 6, 2011.
[2] Normal vent rate based on 1999 TA data + 20% for conservancy.
[3] Duration based on 1999 TA restart duration of 7 hrs. 12 hrs was chosen to be conservative.
[4] Maximum Hourly Vent Rate is estimated to be 1.25 times the normal hourly vent rate.
[5] Waste Stream Heating Value [Btu/lb] = Sum of [(Vent gas composition [wt%])*(Higher Heating Value [Btu/lb])] for each pollutant in the vent gas
[6] Per 40 CFR Part 98 dated July 12, 2010, Table A-1 of Subpart A -*Global Warming Potentials (100-year time horizon)* ; used to convert emissions of each GHG to a CO_2 equivalent basis.

Un-combusted Material Emissions (Quantites Passing Through Flare)

Component	Normal Vent to Flare[1]	Maximum Vent to Flare[2]	Flare DRE[3]	Normal Emission Rate[4]	Global Warming Potential	CO2e Emission Rates from Corresponding GHG Pollutants[5]		
	(lb/hr)	(lb/hr)	(%)	(lb/hr)		(lb/hr)	(MTCE/yr)	(tpy)
H_2	13,366	16,707	99%	--	--	--	--	--
CO	37,161	46,451	98%	743	--	--	--	--
CH_4	5,854	7,317	99%	59	21	1,537	13.39	14.75
CO_2	34,234	42,792	0%	34,234	1	42,792	372.78	410.81
					Sub-Total Emissions =	44,329	386	426

[1] Normal Vent to Flare (lb/hr) = (Normal Hourly Vent Rate [lb/hr])*(Vent Gas Composition [wt%])/100
[2] Maximum Vent to Flare (lb/hr) = (Maximum Vent Rate [lb/hr])*(Vent Gas Composition [wt%])/100
[3] *TCEQ Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers* (October 2000), Table 4.
[4] Normal Emission Rate (lb/hr) = (Normal Vent to Flare [lb/hr])*(1-Flare DRE [%])
[5] Hourly Emission Rate (lb/hr) = (Maximum Vent to Flare [lb/hr]) * (1-Flare DRE [%]) * (Global Warming Potential)
Annual Emission Rate (tpy) = (Normal Emission Rate [lb/hr]) * (Annual Venting Basis [events/yr]) * (Venting Duration [hrs/event]) * (Global Warming Potential) / (2000 lb/ton)
Annual Emission Rate (MTCE/yr) = (Annual Emission Rate [tpy]) * (1 tonne / 1.102 tons)

Example Calculation
Normal Vent Rate to Flare (lb/hr Total) = 90,614 lb/hr (basis is 1999 turnaround calculation data)
Normal Vent Rate to Flare (lb/hr CH4) = 90,614 lb/hr * 6.5 wt% / 100 = 5,854 lb/hr H2
Normal Emission Rate (lb/hr CH4) = 5,854 lb/hr * (1 - 99% DRE) = 58.54 lb/hr

Combustion Emissions (Carbon Materials Converted to CO_2)

Component	Maximum Combusted Material[1]		Molecular Weight of Component	No. of Carbon Atoms	Carbon Weight	Normal Combusted Material[2]		CO_2e from CO_2 (Combustion of CO and Methane)[3,4]		
	(lb/hr)	(Btu/hr)	(lb/lbmol)		(%)	(lb/yr)	(tpy)	(lb/hr)	(MTCE/yr)	(tpy)
H_2	16,540	1,017,483,382	2	0	0%	--	--	--	--	--
CO	45,522	197,743,831	28	1	43%	874,022	437.01	71,535	623	687
CH_4	7,244	175,252,813	16	1	75%	139,083	69.54	19,921	174	191
							Sub-Total Emissions =	91,455	797	878
							TOTAL EMISSIONS =	135,989	1,186	1,306

[1] Maximum Combusted Material (lb/hr) = (Maximum Vent to Flare [lb/hr])*(Flare DRE [wt%])
Maximum Combusted Material (Btu/hr) = (Maximum Combusted Material [lb/hr])*(Higher Heating Value [Btu/lb])
[2] Normal Combusted Material (lb/yr) = (Normal Vent to Flare [lb/hr]) * (Flare DRE [wt%]) * (Annual Venting Basis [events/yr]) * (Duration [hrs/event])
[3] Assume that all carbon from components in waste gas stream is converted to carbon dioxide.
[4] CO_2 Hourly Emissions (lb/hr) = (Maximum Combusted Material [lb/hr]) * Wt% of Carbon * (Molecular Weight of CO2 [lb/lbmol]) / (Molecular Weight of C [lb/lbmol]) * Global Warming Potential
Annual CO_2e Emissions (tpy) = (Normal Combusted Material [tpy]) * Wt% of Carbon * (Molecular Weight of CO2 [lb/lbmol]) / (Molecular Weight of C [lb/lbmol]) * Global Warming Potential
Annual CO_2e (MTCE/yr) = Annual CO_2e Emissions [tpy] * (1 tonne /1.102 ton).
Note: MW of CO_2 = 44, MW of Carbon = 12, to convert mass of Carbon to mass of CO_2 use the MW ratio 44/12.

GHG Emission Factors - Petroleum Combustion

Greenhouse Gas	Emission Factor[1] (kg/MMBtu)	Global Warming Potential[2]
CH_4	3.0E-03	21
N_2O	6.0E-04	310

[1] Per 40 CFR Part 98 dated December 17, 2010, Table C-1 of Subpart C -*Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel* and Table C-2 of
[2] Per 40 CFR Part 98 dated July 12, 2010, Table A-1 of Subpart A - Global Warming Potentials (100-year time horizon); used to convert emissions of each GHG to a CO2 equivalent

Combustion Emissions (CO2e converted from CH4 & N2O)

Component	Combusted Material		CO2e from CH4[2]	CO2e from N2O[2]	CO_2e Total (Combusion of Organics)[2]	
	(lb/hr)	(Btu/hr)[1]	lb/hr	lb/hr	(lb/hr)	(tpy)
H2	16,540	1,017,483,382	--	--	--	--
CO	45,522	197,743,831	27	81	108	1.30
CH4	7,244	175,252,813	24	72	96	1.15
				Sub-Total Emissions =	204	2.45

[1] Heat Input Capacity = (Vent rate [lb/hr])*(Higher Heating Value [Btu/lb])
[2] Sample Calculation for CO_2 emissions
CO_2 Emission Rate (CO_2e lb/hr) = (Emission Factor [kg/MMBtu]) * 2.2 lb/kg * (Global Warming Potenial) * (Heat Input Capacity [MMBtu/hr]) /(10^6 Btu/MMBtu) *
CO_2 Emission Rate (CO_2e tpy) = CO2e (lb/hr) * duration (hrs/yr) / 2000 lb/ton

Equistar Chemicals, LP
Channelview North Facility, TX
Methanol Restart Jun-12
NSR Permit No. 8125
Column Start-up
EPN: EMEOHFLARE (Methanol Flare)
FIN: MEOHFLARE

Calculation Basis		
Annual Venting Basis	1	events/yr
Normal Vent Rate[1]	6,222	lb/hr
Duration[2]	48	hrs per event
Maximum Vent Rate[3]	7,488	lb/hr
Higher Heating Value	9,838	Btu/lb
Global Warming Potential[4]		
CO_2	1	

[1] Normal Hourly Vent Rate based on 1999 TA data.
[2] Duration based on 1999 TA restart duration. 1999 restart lasted 90 hr 46 min but 48 was chosen as more typical.
[3] Maximum Vent Rate supplied by Equistar.
[4] Per 40 CFR Part 98 dated July 12, 2010, Table A-1 of Subpart A - Global Warming Potentials (100-year time horizon); used to convert emissions of each GHG to a CO2 equivalent basis.

Combustion Emissions

Component	**Flare DRE[1]**	**Maximum Hourly Combusted Material[2]**		**Normal Annual Combusted Material[3]**		**Molecular Weight**	**No. of Carbon Atoms**	**Carbon Weight**	**CO_2e from CO_2 (Combusion of Methanol)[4,5]**		
	(%)	**(lb/hr)**	**(Btu/hr)**	**(lb/yr)**	**(tpy)**	**(lb/lbmol)**		**(%)**	**(lb/hr)**	**(MTCE/yr)**	**(tpy)**
CH_3OH	99%	7,413	72,930,275	295,669	147.83	32	1	38%	**10,193**	**184**	**203**
							TOTAL EMISSIONS =		**10,233**	**186**	**204**

[1] TCEQ Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers (October 2000), Table 4.
[2] Maximum Combusted Material (lb/hr) = (Maximum Vent to Flare [lb/hr])*(Flare DRE [wt%])
Maximum Combusted Material (Btu/hr) = (Maximum Combusted Material [lb/hr])*(Higher Heating Value [Btu/lb])
[3] Normal Combusted Material (lb/yr) = (Normal Vent to Flare [lb/hr])*(Annual Venting Basis [events/yr])*(Duration [hr/event])*(Flare DRE [wt%])
[4] Assume that all carbon from components in waste gas stream is converted to carbon dioxide.
[5] CO_2 Hourly Emissions (lb/hr) = (Maximum Combusted Material [lb/hr])* Wt% of Carbon*(Molecular Weight of CO_2 [lb/lbmol])/(Molecular Weight of C [lb/lbmol])*(Global Warming Potential)
CO_2 Annual Emissions (tpy) = (Normal Combusted Material [tpy])* Wt% of Carbon*(Molecular Weight of CO_2 [lb/lbmol])/(Molecular Weight of C [lb/lbmol])*(Global Warming Potential)
Annual CO_2e (MTCE/yr) = Annual CO_2e [tpy] * (1 tonne /1.102 ton).
Note: MW of CO_2 = 44, MW of Carbon = 12, to convert mass of Carbon to mass of CO_2 use the MW ratio 44/12.

Example Calculation
Maximum Combusted Material (lb/hr) = 7,488 lb/hr * 99% DRE = 7,413 lb/hr
Maximum Combusted Material (Btu/hr) = 7,413 lb/hr * 9,838 Btu/lb = 72,930,275 Btu//hr

GHG Emission Factors - Petroleum Combustion

Greenhouse Gas	**Emission Factor [1]**	**Global Warming Potential [2]**
	(kg/MMBtu)	
CH_4	3.0E-03	21
N_2O	6.0E-04	310

[1] Per 40 CFR Part 98 dated December 17, 2010, Table C-1 of Subpart C - *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel* and
[2] Per 40 CFR Part 98 dated July 12, 2010, Table A-1 of Subpart A - Global Warming Potentials (100-year time horizon); used to convert emissions of each GHG to a CO2 equivalent

Combustion Emissions (CO2e converted from CH4 & N2O)

Component	**Maximum Hourly Combusted Material[2]**		**CO2e from CH4 [2]**	**CO2e from N2O [2]**	**CO_2e Total (Combusion of Organics)[2]**	
	(lb/hr)	**(Btu/hr) [1]**	**lb/hr**	**lb/hr**	**(lb/hr)**	**(tpy)**
CH3OH	7413.12	72,930,275	10.11	29.84	**40**	**1**

[1] Heat Input Capacity = (Vent rate [lb/hr])*(Higher Heating Value [Btu/lb])
[2] Sample Calculation for CO_2 emissions
CO_2 Emission Rate (CO_2e lb/hr) = (Emission Factor [kg/MMBtu]) * 2.2 lb/kg * (Global Warming Potenial) * (Heat Input Capacity [MMBtu/hr]) /(10^6 Btu/MMBtu) *
CO_2 Emission Rate (CO_2e tpy) = CO2e (lb/hr) * duration (hrs/yr) / 2000 lb/ton

Equistar Chemicals, LP

Channelview Facility
Methanol Restart Jun-12
NSR Permit No. 8125

Fugitive Components
EPN: EFUGMEOH

Unsure if we can detect CO2 - should we use 30% control

Components[1]	Phase	SOCMI w/o C_2 Emission Factor[2]	CO2 Control Efficiency[3,11]	LAER (CH4) Control Efficiency[3]	Component Count[1,4]	Global Warming Potential for CH_4	Global Warming Potential for CO_2	CO_2e from Controlled CH_4 Emission Rates[5,6,7]			CO_2e from Controlled CO_2 Emission Rates [8,9,10]			Total CO_2e from All Controlled Emission Rates		
		(lb/hr/component)	(%)	(%)				(lb/hr)	(MTCE/yr)	(tpy)	(lb/hr)	(MTCE/yr)	(tpy)	(lb/hr)	(MTCE/yr)	(tpy)
Valves	Gas/ Vapor	0.0089	30%	97%	1,239	21	1	6.95	27.61	30.43	3.86	15.34	16.90	10.81	42.95	47.33
Valves - DTM[12]	Gas/ Vapor	0.0089	30%	75%	37	21	1	1.74	6.90	7.61				1.74	6.90	7.61
Relief Devices	Gas/ Vapor	0.2293	30%	97%	7	21	1	1.01	4.02	4.43	0.56	2.23	2.46	1.57	6.25	6.89
Flanges/Connectors	Gas/ Vapor	0.0029	30%	97%	3,717	21	1	6.79	26.99	29.74	3.77	15.00	16.52	10.56	41.99	46.27
Flanges/Connectors - DTM[12]	Gas/ Vapor	0.0029	30%	75%	279	21	1	4.24	16.87	18.59				4.24	16.87	18.59
Compressor Seals	Gas/Vapor	0.5027	30%	95%	4	21	1	2.11	8.39	9.25	0.70	2.80	3.08	2.82	11.19	12.33
TOTAL EMISSIONS (all compounds)							**Total :**	**22.84**	**91**	**100.05**	**8.90**	**35**	**38.97**	**31.74**	**126**	**139.02**

[1] Components were assumed to conservatively contain 100% CH_4 and 50% CO_2, thus overestimating potential GHG emissions.

[2] SOCMI without C_2 factors are based on the concentration of the stream.

[3] Control efficiency values obtained from *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, Air Permits Division, TCEQ* (October 2000).

[4] Component count represents the estimated component count + 10% safety factor added to be conservative.

[5] Hourly CO_2e from Controlled CH_4 Emission Rate (lb/hr) = (SOCMI w/o C_2) * 100% GHG composition * (Component Count + 10% Safety Factor) * (1-Control Efficiency [%]) * (Global Warming Potential).
For this calculation, assumed the entire stream (100%) was CH_4.

[6] Annual CO_2e from Controlled CH_4 Emission Rate (tpy) = (Hourly Controlled CH_4 Emission Rate [lb/hr])*(Hours of Operation [hr/yr])*(2000 lb/ton).

[7] Annual CO_2e from Controlled CH_4 Emission Rate (MTCE/yr) = Annual CO_2e from Controlled CH_4 Emission Rate (tpy) * (1 tonne /1.102 ton)

[8] Hourly CO_2e from Controlled CO_2 Emission Rate (lb/hr) = (SOCMI w/o C_2) * 50% GHG composition * (Component Count + 10% Safety Factor) * (1-Control Efficiency [%]) * (Global Warming Potential).
For this calculation, assumed 50% of the stream was CO_2.

[9] Annual CO_2e from Controlled CO_2 Emission Rate (tpy) = (Hourly Controlled CH_4 Emission Rate [lb/hr])*(Hours of Operation [hr/yr])*(2000 lb/ton).

[10] Annual CO_2e from Controlled CO_2 Emission Rate (MTCE/yr) = Annual CO_2e from Controlled CH_4 Emission Rate (tpy) * (1 tonne /1.102 ton)

[11] OVA control only for CO2 monitoring due to inability of PID analyzer to read CO2

Equistar Channelview Methanol Restart - GHG Monitoring, Recordkeeping and Reporting

Summary

The restart project at Equistar Channelview's Methanol Unit will result in increased emissions of greenhouse gases (GHGs) from three types of sources. These sources with increase emissions include the reformer, flares, and fugitive sources in GHG service. To provide demonstration of compliance with emissions limitations for GHGs, Equistar is proposing monitoring methods appropriate for each GHG emitted from each source, recordkeeping for verification of the monitoring, and periodic reporting to EPA of the monitoring results and compliance status.

In addition, Equistar will incorporate GHG BACT into the design and operation of the new facilities. Equistar is proposing monitoring, recordkeeping and reporting appropriate for demonstration that GHG BACT is continuously employed.

It is further proposed that the GHG monitoring, recordkeeping and reporting presented in this document be applicable to only those sources specifically listed in this document. GHG emissions limitations apply to only new and increased emissions of greenhouse gases.

This document addresses each source type individually with proposals for monitoring recordkeeping and reporting.

Reformer Monitoring, Recordkeeping and Reporting

The reformer stack is a source of CO_2, CH_4 and N_2O emissions. CO_2 emissions are a function of firing rate, fuel selection, and completeness of combustion. Equistar proposes to determine CO_2 emissions rate on the basis of a carbon balance. CH_4 and N_2O emissions estimates for the reformer will be based on emissions factors from 40 CFR Part 98, Subpart C, and the firing rate for the reformer. The GHG emissions at anticipated maximum annual firing rates and reformer utilization are provided below.

Reformer	Pollutant	TPY Pollutant	TPY CO_2e	% Total CO_2e
EHTF7001	CO_2	826,600	826,600	99.90
	CH_4	15.6	327	0.04
	N_2O	1.6	483	0.06
		TOTALS	827,400	100.00

It will be assumed that 100% of the carbon content of the fuel gas is converted to CO_2. There will be a small fraction of the carbon that is emitted as CO and as CH_4, however those fractions are small. Of the total carbon input to the reformer, only 0.05% is expected to be emitted as CO and <0.01% is expected to be emitted as CH_4. Therefore primary interest is appropriately placed on accurate estimation of CO_2 emissions.

The factors for CH_4 and N_2O emissions are taken from 40 CFR Part 98, Subpart C, Table C-2, *Default CH_4 and N_2O Emission Factors for Various Types of Fuel,* excerpt below:

Fuel type	Default CH_4; emission factor (kg CH_4;/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
Natural Gas	1.0×10^{-03}	1.0×10^{-04}

GHG BACT for the reformer has been determined to be fuels selection. In addition, Equistar will utilize a reformer with high energy efficiency and will employ certain best operational practices to maintain that energy efficiency. Equistar will maintain records of fuel use (flow and composition) for demonstration of fuel selection, and will measure and record excess oxygen and stack temperature for demonstration of energy efficiency.

Carbon Dioxide (CO_2)

The CO_2 emissions from the reformer represent 99.9% of the CO_2e emissions from the reformer. It is proposed that the CO_2 emissions be based on a carbon balance. The measured input carbon mass will be based on metered, controlled fuel flow to the reformer and continuous analysis of the fuel composition using an online chromatograph. This combination will also provide the basis for firing rate determination.

Fuel gas flow is measured with orifice meters, using differential pressure measurement. The meters are both pressure and temperature compensated to assure accurate measurement. The volumetric fuel flow meter output will be used to determine flow rate at least once each fifteen minutes. The fuel flow is recorded and is an input to the continuously calculated firing rate.

The fuel, being a combination of natural gas and plant produced fuel gases, is analyzed to determine its composition. The fuel will be fed from fuel gas drum D-7020 where plant produced gases, primarily methane and hydrogen, and natural gas are mixed prior to being routed to combustion devices. The analyzers will receive samples at least once each hour. The analyzer outputs provide the concentrations of hydrogen, methane, ethane, methanol, water, nitrogen, CO_2, and C3+.

With the measured fuel gas composition, the mass fraction of each compound is then determined. Those data and the known carbon content of each chemical species in the stream are used to calculate the total carbon content of the fuel gas.

The following is a simplified example showing how the carbon content of the fuel gas relates to the individual compound volume concentrations. The volume % in the example is for illustration purposes only and is equivalent to mole fractions.

Compound	Formula	MW	Vol%	Weight[1]	Wt. %[2]	Compound %C[3]	%C in Stream[4]
Hydrogen	H_2	2	40	0.8	7.4%	0	0
Methane	CH_4	16	57	9.12	84.3%	75	63.22
Methanol	CH_3OH	32	1	0.32	3.0%	38	1.11
Carbon Monoxide	CO	28	1	0.28	2.6%	43	1.11
Ethane	C_2H_6	30	1	0.3	2.8%	80	2.22
		TOTALS	100	10.82	100.0%		70.26

1. Volume percent multiplied by the MW provides the equivalent weight of the compound on a 100 moles of total fuel gas basis.
2. The weight of each compound divided by total weight of gas in 100 moles.
3. Carbon number multiplied by two then divided by compound MW.
4. Weight percent of compound in the stream multiplied by the weight fraction of carbon in the compound provides the carbon contribution of the overall stream mass.

With the measured fuel flow to the reformer, and the known carbon concentration, the mass of carbon introduced to the reformer as fuel is known. Applying a simple ratio of the molecular weight of carbon (12) and molecular weight of carbon dioxide (44) provides the estimated CO_2 emissions.

Volumetric flow w/ temperature and pressure + Fuel Gas analysis ⇨ Mass flow of fuel gas + Weight fraction of Carbon ⇨ Weight of Carbon ⇨ CO_2 Emissions

The fuel gas heating value may be determined similarly, using the weight fraction of each compound in the gas, and its associated pure component heating value. The relationship is demonstrated in the example below, using the same hypothetical gas mixture presented above.

Compound	Formula	Btu/lb[5]	Wt. %	Contribution[6] Btu/lb
Hydrogen	H_2	60,957	7.40%	4,532
Methane	CH_4	23,861	84.30%	20,224
Methanol	CH_3OH	9,838	3.00%	295
Carbon Monoxide	CO	4,368	2.60%	114
Ethane	C_2H_6	22,304	2.80%	622
		TOTALS	100.00%	25,787

5. Perry and Chilton, Chemical Engineer's Handbook, 5th Ed., Table 3-203, Heats of Combustion.1973.
6. The heating value (Btu) contribution of that compound to the heating value of 1 pound of fuel gas.

The fuel heating value and fuel flow to the reformer burners is the basis for determining the reformer firing rate.

Volumetric flow w/ temperature and pressure
\+
Fuel Gas analysis
⇨
Mass flow of fuel gas
\+
Fuel Heating Value
⇨
Firing Rate

The firing rate is the basis for the estimation of methane and nitrous oxide emissions.

The unit's distributed control system (DCS) receives inputs from the analyzers and the meters. The computational capability of the DCS is used to convert the inputs to fuel carbon content, fuel flow rates, fuel heating values, reformer firing rates and such. The DCS provides control signals to vales where control is necessary and also sends information to a data historian for records retention.

Methane (CH_4)

Methane emissions from the reformer stack will be estimated based on the continuous fuel flow monitoring and fuel heating value as determined above. Equistar will not make downward adjustment of the estimated of CH_4 emissions due to combustion of hydrogen which has no potential for CH_4 generation, nor any adjustment for the small mole fractions of C_2 and heavier compounds in the fuel gas. The net effect is negligible and should generally err on a conservatively and slightly higher estimated overall CO2e emission.

This CH_4 emissions estimation is straight forward, being based on the firing rate and the factor taken from 40 CFR Part 98, Subpart C, Table C-2, for natural gas combustion; 0.001 kg / MMBtu fired, or 0.0022 lb/MMBtu. The firing rate is based on the temperature and pressure compensated measured fuel flow and calculated fuel gas heating value, both of which are discussed above.

Nitrous Oxide (N_2O)

Nitrous oxide emissions from the reformer stack will be estimated based on the continuous fuel flow monitoring and fuel heating value, in the same manner that CH_4 emissions are estimated. The only difference is the factor for N_2O is lower than the factor for CH_4.

This N_2O emissions estimation is straight forward, being based on the firing rate and the factor taken from 40 CFR Part 98, Subpart C, Table C-2 for natural gas combustion, 0.0001 kg / MMBtu fired, or 0.0002 lb/MMBtu. The firing rate is based on measured fuel flow and calculated fuel gas heating value, both of which are discussed above.

GHG BACT Demonstration

Equistar has determined that GHG BACT for the reformer is fuel selection; use of low carbon intensity fuel. In addition Equistar will incorporate an energy efficient reformer design and will employ operational practices that preserve efficiency.

For demonstration of fuel selection, Equistar will retain records of fuel consumed and the composition of the fuel. This monitoring is more fully described in the CO_2 emissions estimation section of this discussion.

Energy efficiency is demonstrated through a combination of design and operation of the reformer. Equistar proposes to measure exhaust temperature, showing the substantial heat energy has been removed from the combustion gas stream for beneficial use. This temperature will be less than 300°F during normal reformer operations. In addition, the excess oxygen in the combustion gas stream as an indication the excessive air is not being introduced to the firebox which would reduce energy efficiency. During normal reforming operation (non-Startup, non-Shutdown), the combustion gas oxygen concentration will be maintained below 5% vol. O_2.

Summary of Reformer Monitoring, Recordkeeping and Reporting

For purposes of reformer GHG emissions estimation and BACT verification, Equistar proposes to measure fuel flow at least once every 15 minutes and to analyze fuel gas composition at least hourly. Those inputs will be used to determine carbon dioxide emissions potential of the fuel gas, and the fuel gas heating value. It will be assumed that 100% of the carbon in the fuel gas is converted to CO_2 and emitted. The CH_4 and N_2O emissions will be based on factors provided at 40 CFR Part 98, Subpart C, Table C-2, for combustion of natural gas, combined with the reformer firing rate based on measured fuel flow and fuel heating value. The estimated emission of CO_2, CH_4 and N_2O will be determined no less frequently than once per hour and recorded as a daily average for each calendar day. The system for estimating and recording emissions, including fuel metering and analysis, will be operational no less than 95% of the time that the reformer is operating and the meters and analyzers are not undergoing preventative maintenance/calibration.

The fuel gas flow meter will be classified as environmental critical instrumentation thus receiving increased priority for preventative maintenance and repair if needed. The fuel gas flow meters will be calibrated biannually. Records of maintenance and calibration will be created and retained.

The fuel gas analyzer will be classified as environmental critical instrumentation thus receiving increased priority for preventative maintenance and repair if needed. The analyzer will be calibrated at least monthly. Records of maintenance and calibration will be created and retained.

The oxygen analyzer will measure oxygen content of the combustion gases downstream of the of the convection section. Excess oxygen will be controlled to less than 5 percent to ensure efficiency.

Proposed Monitoring, Recordkeeping and Reporting for Reformer

1. Reformer EHTF-7001 is limited to an annual average and a maximum hourly firing rate of 1,615 MMBtu/hour (HHV). Compliance with the annual firing limit for the reformer shall be demonstrated with an annual average firing rate updated on a 12-month rolling basis. Compliance with the hourly maximum firing rate shall be demonstrated with hourly firing records for the reformer. Records shall be updated by the end of the following month.

2. Compliance with the annual emission limit for CO2 from reformer EHTF7001 shall be demonstrated on a rolling 12-month basis calculated as a carbon balance using fuel flow and fuel analysis. Records shall be updated by the end of the following month.

3. Compliance with the annual emission limit for CH4 and N2O emissions from reformer EHTF7001 shall be calculated in accordance with 40 CFR Part 98 Subpart C §98.33(c) on a 12-month rolling basis. Records shall be updated by the end of the following month.

4. Equistar proposes to calibrate and perform preventative maintenance check of the fuel gas flow meters and document biannually.

5. Equistar will monitor and record excess O2 concentration in the combustion gases no less frequently than daily.

6. Equistar will monitor and record the temperature of the combustion gases no less frequently than daily.

7. Equistar proposes to validate oxygen analyzers with zero and span gas at least weekly to maintain 1% accuracy.

8. Equistar proposes to perform and document preventative maintenance check of the oxygen analyzers, including a cylinder gas audit, at least once per quarter.

9. Each six-months, Equistar will report to EPA each deviation from the requirements specified in items 1 through 8 above, for the previous semi-annual reporting period consistent with reporting requirements of 40 CFR Part 70 (71)

Fugitive Emissions Monitoring

The fugitive emissions of CH_4 and CO2 will be estimated on the basis of the count of each type of component in CH_4 and CO2 service and the appropriate emissions factors and leak detection and repair credits for the applied program.

Technology	CH4 Control Effectiveness (%)	CO2 Control Effectiveness (%)	CH_4 Emissions with Control (TPY)	CO2 Emissions with Control (TPY)	CO2e Emissions with Control (TPY)
Instrumented LDAR (28LAER)	97	30	4.76	38.97	139.02

The SOCMI factors for gas/vapor without ethylene of 0.089 lb/hr per valve and 0.0029 lb/hr per connector were used to estimate the fugitive leak rates from valves and flanges. Most of the components will be monitored with an approved gas analyzer quarterly with a 500 ppm leak definition and will repaired or replaced within 15 days unless qualified for delay of repair. The components may be qualified for less frequent monitored if leak rates are less than 0.5 percent. Components in this program qualify for a 97 percent reduction for CH4 service and 30% for CO2 service in the estimated emission rate. A 30% reduction is utilized for components in CO2 service due to the inability of the PID analyzer to detect CO2.

Some components are expected to be difficult to monitor due to their location and may only be monitored with an instrument once per year. These components receive an estimated 75 percent reduction in their emission rate.

A small percentage of components may be exempt from monitored due to being inaccessible (such as being under insulation) or unsafe to monitor. All of the components will be observed weekly by visual, olfactory, and auditory methods during routine operator rounds. This gives an estimated 30 percent reduction in the emission rate as compared to having no leak detection and repair program.

Using the 28LAER program as described reduces the estimated fugitive GHG emissions by approximately 94 percent overall.

Proposed Monitoring, Recordkeeping and Reporting for LDAR

1. Records of all monitoring and repair will be generated and maintained as required by the applicable program, e.g., 28LAER.

2. Each six-months, Equistar will report to EPA each deviation from the requirements specified above, for the previous semi-annual reporting period consistent with reporting requirements of 40 CFR Part 70 (71).

Flare Monitoring

There are two sources of increased GHG emissions from the flares resulting from this project. The first is combustion of waste gases in the flares. The second is combustion of sweep gas, which is natural gas fed into the flare to prevent entry of air into the flare header that could create an explosive mixture within the flare stack and header. The increased waste gas emissions only occur during startup, shutdown, or maintenance activities.

The methanol unit will have two new flares constructed as part of the project. One of these flares is a continuous flare (EMEOHFLARE), meaning that it be continuously situated to receive waste gases from the methanol unit. The other is for high waste gas flow rates that exceed the capacity of the continuous flare (EEMERFLARE). During normal operation there are no waste gas flows produced by the unit that are routed to the flares. The only gases flowing continuously to the flare are pilot gas and sweep gas on the continuous flare.

It is important to note that the only increase in flare emissions associated with this project is from maintenance, startup and shutdown (MSS) activities to the continuous flare (EMEOHFLARE), and from existing East Plant Flare 17E01, which will control methanol loading emissions. The only material sent to 17E01 is methanol.

Flares EMEOHFLARE & EEMERFLARE

The waste gas from the unit is mixed with sweep gas (natural gas) upstream of a **mass flow meter** located in the flare header. The mixed gas stream is also analyzed for composition. Using the composition and flow rate, the total mass of carbon routed to the flare is quantified. It is assumed that 100% combustion to CO_2 takes place and the derived value is the mass of CO_2 generated from waste gas and sweep gas flaring. In addition, the heat release from combustion of the gases is used as the basis for the CH_4 and N_2O emissions estimate using the petroleum combustion factors from 40 CFR Part 98, Subpart C.

In addition, uncombusted CH4 and CO2 in the flare gas will be calcualated using a 99% destruction efficiency for CH4 and 0% for CO2.

Natural gas flow to the flare pilots will be estimated based on the maximum pilot design flow in combination of a pre-determined heating value of 1040 btu/scf will be utilized to determine the net heat release from the pilots. With the known heat release, CO2, CH_4 and N_2O emissions factors for natural gas combustion taken from 40 CFR Part 98, Subpart C, Table C-2 are applied to the heat release to determine the CO2, CH_4 and N_2O emissions estimates.

The flare header flow meter will determine flow at least once each 15 minutes, and block one hour flow records will be maintained. The flow meter will be calibrated at least biannually. The flare gas flow meter will be classified as environmental critical instrumentation thus receiving increased priority for preventative maintenance and repair if needed. The flow meters will have at least 95% online reliability for periods when the flare is in service and the flow meter is not being calibrated.

The flare analyzers will provide gas composition at least once each hour. The analyzers will be calibrated monthly. The flare gas analyzer will be classified as environmental critical instrumentation thus receiving increased priority for preventative maintenance and repair if needed. The analyzer will have at least 95% online reliability when the flare is in service and the analyzer is not being calibrated.

Proposed Monitoring, Recordkeeping and Reporting for EMEOHFLARE

Records will be maintained which demonstrate meter and analyzer reliability.

1. Equistar will retain records of block one hour flare flow rates to be updated at least once each month for the previous month.

2. Equistar will retain records of flare gas analysis to be updated at least once each month for the previous month.

3. Equistar will produce and retain a rolling 12-month estimate of GHG emissions from the flare to be updated by the end of the following month.

4. Each six-months, Equistar will report to EPA each deviation from the requirements specified in items 1 through 3 above, for the previous semi-annual reporting period consistent with reporting requirements of 40 CFR Part 70 (71).

Flare 17E01

Methanol will be loaded into trucks and railcars. The emissions from the loading activity will normally be controlled via a condenser in combination with the flare, 17E01. During times of downtime of the condenser (permit basis of 30 loading days a year), the loading emissions will be vented directly to the flare. A 90% recovery efficiency of the condenser is utilized to estimate emissions resulting emissions to the flare. The methanol loading emissions to the flare, 17E01, will be determined based on AP-42 Fifth Edition, Volume I, Section 5.2 Transportation And Marketing Of Petroleum Liquids, based on the known loading quantity, along with taking credit for the recovery efficiency of the condenser, as applicable. Using the known composition and calculated vent rate, the methanol carbon content (38 wt%) and the ratio of the molecular weight of CO2 to carbon (44/12), the total mass of carbon routed to the flare is quantified. It is assumed that 100% combustion to CO_2 takes place and the derived value is the mass of CO_2 generated from methanol loading vent gas to the flare. In addition, the heat release from combustion of the methanol gas is used as the basis for the CH_4 and N_2O emissions estimate utilizing the petroleum combustion factors from 40 CFR Part 98, Subpart C. The heat release due to the methanol loading is calculated by multiplying the high heating value of methanol times the vent gas rate.

Proposed Monitoring, Recordkeeping and Reporting for Flare 17E01

Records will be maintained which demonstrate loading meter reliability.

1. Equistar will retain records of loading quantities to be updated at least once each month for the previous month.

2. Equistar will retain records of periods when the condenser is out of service to be updated at least once each month for the previous month.

3. Equistar will produce and retain a rolling 12-month estimate of GHG emissions from the flare due to methanol loading to be updated by the end of the following month.

4. Each six-months, Equistar will report to EPA each deviation from the requirements specified in items 1 through 3 above, for the previous semi-annual reporting period consistent with reporting requirements of 40 CFR Part 70 (71).

From: "Warnement, Tom E" <Tom.Warnement@lyondellbasell.com>
To: Melanie Magee/R6/USEPA/US@EPA
Cc: "Gaspard, Darren P" <Darren.Gaspard@lyondellbasell.com>
Date: 07/06/2012 10:03 AM
Subject: Response - May 02, 2012 Application Completeness Determination

Ms. Magee

Equistar Chemicals – Channelview Facility (Equistar) has prepared this correspondence to address the EPA's information request in the Application Completeness Determination letter sent May, 02, 2012. Attached to the correspondence is an updated Greenhouse Gas (GHG) permit application document including updated GHG emission estimates, a Monitoring, Recordkeeping and Reporting Proposal(MRR), updated revisions to the TCEQ PSD/NSR permit application and TCEQ's Air Permit Technical Guidance for Chemical Sources Flares and Vapor Oxidizers.

Equistar has prepared a revise GHG permit application document. The document includes revisions to the Section 9 GHG BACT discussion submitted to the EPA offices on October 27, 2011. The revised GHG BACT discussion addresses questions 1 and 3-11 of the Application Completeness Letter. Equistar has addressed the EPA's request for monitoring information by developing a MRR document which details Equistar's proposal for monitoring, recordkeeping and reporting. GHG emissions estimates for flares have been updated by adding the example calculations requested. An Emergency flare (EEMERFLARE) has been added to the scope of the project. The emergency flare will be designed with a water seal to separate the emergency flare from the process flare. The attached EEMERFLARE emissions estimates represent the combustion of natural gas to operate the flare pilots. GHG estimates from fugitive emissions have been updated to account for difficult to monitor components (DTM). The control efficiency for the DTM was revised to account for the reduced monitoring frequency from quarterly to annual.

Short term emission limitations, requested in Application Completeness Letter comment 5, have been added to the emission estimates and summarized on the attached table 1(a) summary located on page 81 of the file "Equistar MeOH GHG Permit Application V2 06202012".

The following are responses to EPA questions 2 and 12 of the Application Completeness Letter:

Question 2 Response:

The methanol unit is an existing unit, being returned to service after having been shut down for several years. While CO2 injection upstream of the synthesis gas compressor as a supplemental feed is possible, it was included in the process description only for completeness. Injection of CO2 results in the following:

1. Increased production of water as a by-product, which has to be removed in the purification step by distillation, resulting in incremental increase in energy usage/gal of product methanol.

2. Decreased of hydrogen produced for export or use as fuel. Consistent with the discussion in the GHG BACT evaluation the net result is a net increase in GHG emissions. This increase in CO2 emissions ranges from 170 tons per day from the stack if the hydrogen is unavailable as fuel causing increased natural gas consumption, to more than 250 tons per day if not offsetting on-purpose hydrogen production elsewhere (*reference reformer furnace CO2 BACT discussion, use of hydrogen as fuel*). This makes the net impact of capturing 200 tons per day from the flue gas for injection to the process a reduction of only 30 tons per day to an potential increase of more than 50 tons per day.

   Equistar would not consider installation of a CO2 capture system to provide CO2 for injection as supplemental feed because the cost for carbon dioxide by bulk delivery is in the range of $ 5 - $20 per ton compared to the cost of carbon dioxide recovery and reuse from the Flue Gas, which on small demonstration units has been in the range of $80 - $150 per ton.

The design basis for this methanol unit has been optimized to balance the available CO2 from the Reforming step and the utilization of the Synthesis Loop Purge Gas to the fullest extent to mitigate CO2 produced overall, in the production of the Methanol Product.

Question 12 Response:

The methanol unit is an existing unit, being returned to service after having been shut down for several years. The chiller system was used in the former unit to reduce emissions associated with the loading of methanol into trucks or railcars. A performance test was conducted on the chiller while the methanol unit was in service. The chiller demonstrated a recovery efficiency of greater than 90%. The design of the chiller is not expected to change. The loading calculation uses an estimate of 30 days allotted to the chiller system being out of service due to maintenance and repair. The 30 day time period allows for maintenance planning and obtaining necessary parts.

The composition of the loading emissions to the East Plant Flare (EPN 17E01) is based on loading of methanol product. Flow rates to the flare are based on emissions resulting from an hourly maximum pump capacity of 18,000 gallons per hour and loading of approximately 67MM gallons/year of methanol. The losses to the flare are based on AP42 Section 5.2.2.1.1.1 (06/08) Loading Equation. An example of the loading calculation has been added to the emissions calculations "Loading East Plant Flare".

The composition of the emissions to the proposed Methanol Flare (EPN EMEOHFLARE) is based on an analysis of process flow diagrams associated with the former unit. Maintenance, start-up and shutdown emissions routed to EMEOHFLARE is based on equipment clearing, reformer start-up and refining column start-up. Equipment clearing flow rates are based on equipment volumes. The equipment volumes are based on actual equipment size with a 20% factor added for piping. Hourly flow rates are based on a conservative estimate of 24 hours to clear the entire unit. The annual flow rate for equipment clearing is based on one event per year. The reformer and refining column start-up flows are based on actual historical engineering estimates. Reformer startup is based on two events per year.

Pilot flow rates are estimates based on four pilots per flare tip. The natural gas flow rate is based on existing flare pilots located at the site.

Please do not hesitate to contact me if you have any questions.

Thank you,

Thomas Warnement
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Channelview Complex
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Equistar MeOH GHG Permit Application v2 062012.pdf

MeOH MRR July 2012.pdf

Methanol PSD Permit June 2012 update.pdf

Flare and Vapor Oxidizer Guidance Document 2000.pdf

Equistar Chemicals, LP
Channelview North Facility, TX
Methanol Restart Jun-12
NSR Permit No. 8125

Criteria Pollutant Potential Emissions (Project Increases ONLY)

			Hourly Emissions (lb/hr)								Annual Emissions (tpy)							
EPN	**FIN**	**Emission Sources**	**NO_x**	**CO**	**SO_2**	**VOC**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**NH_3**	**NO_x**	**CO**	**SO_2**	**VOC**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**NH_3**
Normal Operation Emissions																		
EHTF7001	HTF7001	Reformer Furnace	134.05	27.46	0.95	8.71	1.87	1.87	1.87	3.59	75.76	120.25	4.16	38.14	8.18	8.18	8.18	15.41
ECT MEOH	CTMEOH	Cooling Tower	--	--	--	2.52	0.45	0.22	0.22	--	--	--	--	4.73	1.97	0.99	0.99	--
ETK3122	31TK3122	Emergency Surge Tank	--	--	--	3.24	--	--	--	--	--	--	--	0.34	--	--	--	--
17E01	17FL1701	East Plant Flare - Product Loading	0.02	0.12	--	0.37	--	--	--	--	0.01	0.04	--	0.69	--	--	--	--
ETK5101 / ETK5102	31TK5101 / 31TK5102	Product Tanks	--	--	--	4.38	--	--	--	--	--	--	--	8.20	--	--	--	--
EFUGMEOH / EFUGNH3	FUGMEOH / FUGNH3	Equipment Fugitives	--	--	--	0.99	--	--	--	0.14	--	--	--	4.31	--	--	--	0.63
EMEOHFLARE	MEOHFLARE	Methanol Flare	6.88	35.05	0.06	0.53	--	--	--	--	1.28	6.55	0.01	0.10	--	--	--	--
EEMERFLARE	EMERFLARE	Emergency Flare	0.02	0.12	0.00	0.00	--	--	--	--	0.11	0.54	0.00	0.01	--	--	--	--
EMEOHANLZ	MEOHANLZ	Methanol Analyzer Vents	--	0.12	--	0.56	--	--	--	--	--	0.54	--	2.42	--	--	--	--
	Total Emissions from Normal Operations =		**140.97**	**62.87**	**1.01**	**21.31**	**2.32**	**2.09**	**2.09**	**3.73**	**77.15**	**127.91**	**4.17**	**58.94**	**10.15**	**9.17**	**9.17**	**16.04**
MSS Emissions																		
E-NMSSROUT	NMSSROUT	MSS	--	--	--	5.58	--	--	--	--	--	--	--	0.07	--	--	--	--
EMEOHFLARE	MEOHFLARE	Methanol Flare	101.60	1094.18	0.11	84.91	--	--	--	--	3.082	17.79	0.01	1.60	--	--	--	--
	Total Emissions from MSS Operations =		**101.60**	**1094.18**	**0.11**	**90.49**	**--**	**--**	**--**	**--**	**3.082**	**17.79**	**0.01**	**1.67**	**--**	**--**	**--**	**--**

[1] NO_X emissions from the reformer furnace are controlled bya Selective Catalytic Reduction (SCR) system.

[2] A 2% SCR downtime is expected annually for maintenance operations. Annual NO_X emissions represent total controlled and uncontrolled emissions.

Potential Emissions from PBRs being Rolled-in

				Hourly Emissions (lb/hr)								Annual Emissions (tpy)							
EPN	**FIN**	**Emission Sources**	**Authorization**	**NO_x**	**CO**	**SO_2**	**VOC**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**NH_3**	**NO_x**	**CO**	**SO_2**	**VOC**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**NH_3**
ETK5101	31TK5101	Product Tank	PBR Registration No. 87006	--	--	--	2.60	--	--	--	--	--	--	--	5.85	--	--	--	--
17E01	17FL1701	East Plant Flare (MeOH Loading to Flare)	PBR 106.473	0.01	0.05	--	0.14	--	--	--	--	0.01	0.03	--	0.08	--	--	--	--
ESP7045	ESP7045	Compressor Lube Oil Reservoir Vent	PBR 106.472	--	--	--	0.05	--	--	--	--	--	--	--	0.23	--	--	--	--
		Total Emissions from PBRs being Rolled-in =		**0.01**	**0.05**	**--**	**2.79**	**--**	**--**	**--**	**--**	**0.01**	**0.03**	**--**	**6.15**	**--**	**--**	**--**	**--**

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date	June 2012	**Permit No.:**	8125	**Regulated Entity No.:**	100542281
Area Name:	Equistar Chemicals, LP, Channelview North Facility			**Customer Reference No.:**	600124705

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

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component of Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**Pounds per Hour (A)**	**TPY (B)**
EHTF7001	HTF7001	Reformer Furnace	NO$_x$	134.05	75.76
			CO	27.46	120.25
			SO$_2$	0.95	4.16
			VOC	8.71	38.14
			PM	1.87	8.18
			PM$_{10}$	1.87	8.18
			PM$_{2.5}$	1.87	8.18
			NH$_3$	3.59	15.41
ECT MEOH	CTMEOH	Cooling Tower	VOC	2.52	4.73
			PM	0.45	1.97
			PM$_{10}$	0.22	0.99
			PM$_{2.5}$	0.22	0.99
ETK3122	31TK3122	Emergency Surge Tank	VOC	3.24	0.34
17E01	17FL1701	East Plant Flare - Product Loading	NO$_x$	0.03	0.01
			CO	0.17	0.06
			VOC	0.51	0.77
ETK5101 / ETK5102	31TK5101 / 31TK5102	Product Tanks	VOC	4.38	8.20
EFUGMEOH / EFUGNH3	FUGMEOH / FUGNH3	Equipment Fugitives	VOC	0.99	4.31
			NH$_3$	0.14	0.63
EMEOHFLARE	MEOHFLARE	Methanol Flare	NO$_x$	108.48	4.37
			CO	1129.23	24.33
			SO2	0.17	0.02
			VOC	91.02	1.77
EEMERFLARE	EMERFLARE	Emergency Flare	NO$_x$	0.02	0.11
			CO	0.12	0.54
			SO2	0.00	0.00
			VOC	0.00	0.01
EMEOHANLZ	MEOHANLZ	Methanol Analyzer Vents	CO	0.12	0.54
			VOC	0.56	2.42
E-NMSSROUT	NMSSROUT	MSS	VOC	5.58	0.07
ESP7045	ESP7045	Compressor Lube Oil Reservoir Vent	VOC	0.05	0.23

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date	June 2012	**Permit No.:**	8125	**Regulated Entity No.:**	100542281
Area Name:	Equistar Chemicals, LP, Channelview North Facility			**Customer Reference No.:**	600124705

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

AIR CONTAMINANT DATA			**EMISSION POINT DISCHARGE PARAMETERS**										
1. Emission Point			**4. UTM Coordinates of Emission**			**5. Building Height (Feet)**	**6. Height Above Ground (Feet)**	**7. Stack Exit Data**			**8. Fugitives**		
(A) EPN	**(B) FIN**	**(C) NAME**	**Zone**	**East (Meters)**	**North (Meters)**			**(A) Diameter (Feet)**	**(B) Velocity (fps)**	**(C) Temperature (ºF)**	**(A) Length (Ft)**	**(B) Width (Ft)**	**(C) Axis Degrees**
EHTF7001	HTF7001	Reformer Furnace	15	295,190	3,302,020		121	14	46.3	270			
ECT MEOH	CTMEOH	Cooling Tower	15	295,438	3,301,900		63	28	15	80	52	129	
ETK3122	31TK3122	Emergency Surge Tank	15	295,414	3,301,985		48						
17E01	17FL1701	East Plant Flare - Product Loading	15	296,251	3,301,800		225	3.5	65.6	1832			
ETK5101	31TK5101	Product Tanks	15	295,517	3,301,403		48						
ETK5102	31TK5102	Product Tanks	15	295,517	3,301,492		48						
EFUGMEOH / EFUGNH3	FUGMEOH / FUGNH3	Equipment Fugitives	15	295,245	3,302,010						600	375	90
EMEOHFLARE	MEOHFLARE	Methanol Flare	15	295,366	3,301,516		190	1					
EEMERFLARE	EMERFLARE	Emergency Flare	15	295,366	3,301,516		190	3					
EMEOHANLZ	MEOHANLZ	Methanol Analyzer Vents	15	295,245	3,302,010		8	0.0033	0.003	Ambient			
E-NMSSROUT	NMSSROUT	MSS	15	295,245	3,302,010								
ESP7045	ESP7045	Compressor Lube Oil Reservoir Vent	15										

EPN = Emission Point Number
FIN = Facility Identification Number

Equistar Chemicals, LP
Channelview North Facility, TX
Methanol Restart
NSR Permit No. 8125 **Jun-12**

EPN: EEMERFLARE (Emergency Flare)
FIN: EMERFLARE

SUPPLEMENTAL NATURAL GAS TO FLARE

Calculation Basis		
Natural Gas to Pilot Flowrate[1]	336	scf/hr
Higher Heating Value	1,050	Btu/scf
Molecular Weights		
CO_2	44	lb/lb-mol
CH_4	16	lb/lb-mol
N_2O	44	lb/lb-mol
Global Warming Potential[3]:		
CO_2	1	
CH_4	21	
N2O	310	

[1] Flowrate based on 4 pilots with 1.4 scfm per pilot.

Emission Factors

Component	Emission Factor		Source
	(lb/MMscf)	(lb/MMBtu)	
NO_x	71.4	0.068	*TCEQ Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers* (October 2000), Table 4, steam-assist, low BTU
CO	363.83	0.3465	
VOC	5.5	5.24E-03	AP-42 Section 1.4 (7/98) Table 1.4-2.
SO_2	0.6	5.71E-04	

Natural Gas Combustion Emissions

Source	Hourly Emissions (lb/hr)[1]				Annual Emissions (tpy)[2]			
	NO_x	CO	VOC	SO_2	NO_x	CO	VOC	SO_2
Flare Pilots	0.02	0.12	1.85E-03	2.02E-04	0.11	0.54	8.09E-03	8.83E-04
Total Emissions =	**0.02**	**0.12**	**0.00**	**0.00**	**0.11**	**0.54**	**0.01**	**0.00**

[1] Hourly Emissions [lb/hr] = (Emission Factor [lb/MMscf])*(Hourly Natural Gas Flowrate [scf/hr])/(10^6 scf/MMscf)

[2] Annual Emissions [tpy] = (Emission Factor [lb/MMscf])*(Annual Natural Gas Flowrate [scf/hr])/(10^6 scf/MMscf)*(8760 hr/yr)/(2000 lb/ton).

FORM PI-2(74-7)

TABLE 6

BOILERS AND HEATERS

Type of Device: Reformer F-7001	Manufacturer:
Number from flow diagram: 1 EPN No. EHTF7001	Model Number:

CHARACTERISTICS OF INPUT

Type Fuel	Typical Chemical Composition (Typical % by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Mixed Fuel	24 - 30% Hydrogen 37 - 58% Methane 3.1 – 8.7 % Methanol 1.7 – 8.2% CO 0.5 – 1.4% Ethane 0.3 – 0.9% C3+ 3.7 – 15 % CO2 1.1 – 1.5% N2 0.1 – 4.6 % H20	Ambient	Average	Expected Design Maximum 44623 – 72270 (lb/hr)
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 416 – 458 BTU/scf	Average __ scfm* 10 % excess (vol)	Expected Design Maximum 243524 scfm* 10 % excess (vol)

HEAT TRANSFER MEDIUM

Type Transfer Medium	Temperature°F		Pressure (psia)		Flow Rate (specify units)	
(Water, oil, etc.)	Input	Output	Input	Output	Average	Expected Design Maxim
(Same as before)						

OPERATING CHARACTERISTICS

Ave. Fire Box Temp. at max. firing rate	Fire Box Volume(ft.^{3}), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)
1930 °F	2 @ 21,000	10.5	2.0

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		Expected (@Ave.Fuel Flow Rate)	Expected (@Max. Fuel Flow Rate)	Temp°F	scfm
14 ft	121 ft		46.3	270 °F	263,700 max

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
CO2	4 – 4.25%
N2	69 – 70%
O2	1.7%
H2O	24.3 – 25%

Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.

Also supply an assembly drawing, dimensioned and to scale, in plan, elevation, and as many sections as are needed to show clearly the operation of the combustion unit.Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F,14.7 psia

TNRCC

October 2000
RG-109 (Draft)

Air Permit Technical Guidance for Chemical Sources:

Flares and Vapor Oxidizers

printed on
recycled paper

Air Permits Division

TEXAS NATURAL RESOURCE CONSERVATION COMMISSION

TNRCC

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Technical Disclaimer

This document is intended as guidance to explain the specific requirements for new source review permitting of flares and vapor oxidizers; it does not supersede or replace any state or federal law, regulation, or rule. References to abatement equipment technologies are not intended to represent minimum or maximum levels of Best Available Control Technology (BACT). Determinations of BACT are made on a case-by-case basis as part of the New Source Review of permit applications. BACT determinations are always subject to adjustment in consideration of specific process requirements, air quality concerns, and recent developments in abatement technology. Additionally, specific health effects concerns may indicate stricter abatement than required by the BACT determination.

The represented calculation methods are intended as an aid in the completion of acceptable submittals; alternate calculation methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data.

These guidelines are applicable as of this document's publication date but are subject to revision during the permit application preparation and review period. It is the responsibility of the applicants to remain abreast of any guideline or regulation developments that may affect their industries.

The electronic version of this document may not contain attachments or forms (such as the PI-1, Standard Exemptions, or tables) that can be obtained electronically elsewhere on the TNRCC Web site.

The special conditions included with these guidelines are for purposes of example only. Special conditions included in an actual permit are written by the reviewing engineer to address specific permit requirements and operating conditions.

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Tables

Chapter 1—Overview

This document is intended to aid the permit applicant in identifying applicable state and federal regulations, and in determining whether a proposed flare or vapor oxidizer system will meet the requirements necessary for a state permit.

This document ***only*** provides guidance for these types of controls at the following types of facilities:

- chemical and petrochemical,
- refining,
- oil and gas processing, and
- chemical and petroleum storage facilities.

Call the TNRCC's New Source Review Permits Division at (512) 239-1250 to obtain guidance on oxidizers used in the following operations:

- solid or liquid waste,
- Resource Conservation and Recovery Act (RCRA),
- boilers and industrial furnaces (BIF), and
- coatings.

The requirements for obtaining a state air permit are discussed in detail and include specific Best Available Control Technology (BACT) guidelines for flare and vapor oxidizer systems, example calculations for permitting purposes and regulatory compliance, and examples of special conditions upon which a state air permit is issued.

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Chapter 2—Types of Flare and Oxidizer Systems

This document provides guidance for two classes of vapor combustion control devices: flares and vapor oxidizers. While there may be some overlap between the two, flares have generally been treated separately by the EPA and the TNRCC, in large part because flares have an open flame and often cannot be sampled, so emissions are estimated based on the results of flare testing performed in the early 1980s. Each of the two classes will be dealt with separately in each of the chapters of this document.

Combustion Control Devices NOT Discussed. This document will not cover permitting of RCRA or BIF units because the requirements for these units often go beyond the requirements for state air permitting. Incinerators used to treat solid wastes are covered in another technical guidance document, *Incinerators*. Guidance for combustion control devices associated with spray paint booths, coatings operations, and semiconductor facilities should be obtained by calling the TNRCC New Source Review Permits Division at (512) 239-1250.

Flares

Flare systems generally are open-flame control devices used for disposing of waste gas streams during both routine process and emergency or upset conditions. In addition to simple, unassisted flares, typical smokeless flare systems include, but are not limited to, the following:

- ***Enclosed Flares/Vapor Combustors.*** Enclosed flares are used in disposing of waste gas streams in instances where a visible flame is unacceptable. Applications include chemical processing, petroleum refining and production, and municipal waste gas treatment. These may be referred to as vapor combustors and can have more than one burner in the stack.

- ***Steam-Assisted Flares***. Steam-assisted flares are used in disposing of low-pressure waste gas streams when steam is available and practical to minimize smoking from the flare. Applications are similar to those of enclosed flares. Flares might also be assisted with natural gas if readily available on site; these flares would undergo a case-by-case review.

- ***Air-Assisted Flares.*** Air-assisted flares are used in disposing of low-pressure waste gas streams when practical or when steam utilities are not available to minimize smoking from the flare. Applications include chemical processing, petroleum refining and production, and pipeline transportation.

- ***Sonic Flares.*** Sonic flares are used in disposing of high-pressure waste gas streams. Applications include gas production, pipeline transportation, and treatment plants.

- ***Multipoint Flare Systems.*** Multipoint flare systems are used in disposing of both high- and low-pressure waste gas streams. Multiple burner tips in conjunction with a staged control system provide for controlled combustion. Applications are similar to those of air-assisted flares.

Vapor Oxidizers

These devices generally do not have an open flame but have an exhaust stack which allows for sampling and monitoring of exhaust emissions. The most common type, thermal, relies on the combustion heat of the waste gas and assist fuel (if required) to oxidize the waste gas air contaminants. Other types include:

- ***Recuperative.*** In this case, the waste gas is directed to a heat exchanger to be preheated by the exhaust gas, to minimize the need for additional assist fuel. Recuperative oxidizers are considered a subset of thermal oxidizers in this document.

- ***Regenerative***. Combustion takes place in a chamber with a heat sink, such as ceramic saddles, which retains the heat of combustion, allowing for combustion of more dilute vapor streams (which have a low heat of combustion) at a lower cost. These units generally have multiple chambers, which allow for the preheat of one chamber by exhaust gases while combustion takes place in another chamber.

- ***Catalytic.*** Combustion takes place over a catalyst that allows for combustion at a lower temperature (in the range of 600 to 800°F as opposed to greater than 1400°F for many thermal oxidizers). Catalytic oxidizers function best with a waste stream with constant flow and composition.

Chapter 3—State and Federal Permitting Requirements

Two types of combustion sources are regulated by the TNRCC: existing sources and new sources. Existing sources were in existence before September 1, 1971, and have not undergone modification. New sources were built or modified after September 1, 1971, which was the date permitting requirements began under Regulation VI (30 TAC Chapter 116) of the TNRCC.[1]

Preconstruction Authorization

A Regulation VI review of a flare or oxidizer could be required due to a planned change in waste stream composition routed to the control device, resulting in an increase in the quantity or character of the actual emissions from the flare or oxidizer. A review might also be triggered by construction to modify a unit, which could include the control device or the process that sends the waste stream to the control device. New or modified sources may be authorized through either an exemption from permitting or by permitting action.

Exemptions

Certain new and modified sources may qualify for an exemption from permitting because their contribution of air contaminants to the atmosphere is considered insignificant. Sources using a flare or oxidizer as a final control device do not need a permit if they meet the requirements for one of the following exemptions:

- Section 106.492 (for flares);
- Section 106.493 (for oxidizers).

In addition, sources using either control device must meet the requirements of Section 106.4.

Permit Options

This guidance document focuses on requirements for a preconstruction permit as required by Regulation VI, Subchapter B. The required information is also very similar for authorization through flexible permit, as required by Regulation VI, Subchapter G. These control devices may also be modified, replaced, or installed through a standard permit (Regulation VI, Subchapter F) if the applicable requirements are met. These permits will require the same calculational methods for any emission estimates, but the required control technology and specific requirements are detailed in the applicable rule.

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[1] **Why Two Numbering Systems?** One of the TNRCC's predecessor agencies classified its (air) regulations by Roman numerals. After creation of the TNRCC, these rules were reclassified under the Texas Administrative Code's Title 30, Environmental Quality, which brings together air and other environmental regulations. Both numbering systems are currently used in everyday reference to air regulations.

Regulation VI does not have specific requirements for flares or oxidizers; however, new sources must apply BACT, taking into account both technical practicability and economic reasonableness. This determination is made on a case-by-case basis, considering the specific circumstances of each application. At a minimum, a new source must meet the applicable state and federal regulatory performance standards for existing sources. More often, new sources will have to perform above and beyond those minimum requirements.

Federal new source permitting programs (prevention of significant deterioration [PSD] and nonattainment) are administered by the TNRCC, through its New Source Review Permits Division. The flare-specific guidelines in this document also apply to those federal programs. It has been TNRCC policy to request that flares used as control devices for new or modified sources at least meet the requirements of 40 Code of Federal Regulations Section 60.18 (40 CFR § 60.18). Further discussion of BACT for flares and vapor oxidizers is provided in the following chapter. Other requirements of Regulation VI, including a review of the protection of public health and welfare (discussed in Chapter 5), also must be met before permit issuance.

General Regulation Applicability

In addition to the requirements of Regulation VI, Table 1 lists other state regulations that apply to existing and new flares and vapor oxidizers.

Table 1. Applicable TNRCC Regulations

Regulation No.	Subject	30 TAC Chapter
I	Visible Emissions	111
II	Sulfur Emissions	112
III	Hydrocarbon Emissions	115

Complete copies of these regulations can be obtained from the TNRCC in several ways:

- visit the agency's Web site, http://www.tnrcc.state.tx.us/oprd/rules/index.html;
- fax your order to (512)239-4488; or
- call (512)239-0028.

Applicable Federal Requirements

New Source Performance Requirements (NSPS). The General Control Device Requirements of 40 CFR §60.18 were issued as a final rule January 21, 1986 are applicable to control devices complying with NSPS promulgated under the Clean Air Act (CAA) and National Emission Standards for Hazardous Air Pollutants (Neshap).

National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT). The Control Device Requirements of 40 CFR § 63.11 were issued as a final rule on March 16, 1994 and are applicable to control devices used to comply with NESHAP under the authority of the CAA Amendments for the control of hazardous air pollutants (HAP).

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Chapter 4—Best Available Control Technology

The BACT determination is performed on a case-by-case basis and is subject to change at any time. Applicants should contact TNRCC's New Source Review Permits Division to verify current BACT requirements before submitting a permit or amendment application. This chapter provides the criteria considered in determining whether a proposed control device meets BACT for flares and vapor oxidizers.

BACT for Flares

Waste Stream Heating Value and Velocity

All new flares in volatile organic compound (VOC) service should normally comply with New Source Performance Standards, Subpart A, Section 60.18 (40 CFR § 60.18).

The calculation methods described there must be used to demonstrate that the flare maintains an acceptable net heating value and exit velocity under all flow conditions (including upset and maintenance.)[1] These parameters promote flame stability and sufficient destruction efficiency. Minimum heating value and maximum tip exhaust gas velocity should be estimated for a flare in accord with 40 CFR § 60.18 under all possible waste flow conditions. The requirements are:

- Net heating value of gas combusted ≥ 300 Btu/scf if steam- or air-assisted, or ≥ 200 Btu/scf if unassisted
- Exit velocity < 60 fps. Exit velocities up to 400 fps allowed if heating value > 1000 Btu/scf, or if $V_{actual} < V_{max}$ with

  $\text{Log}_{10}(V_{max}) = (H_T+28.8)/31.7$ for steam and unassisted flares, or

  $V_{max} = 8.706 + 0.7084(H_T)$ for air-assisted flares

  where: H_T is net heating value of the waste stream (MJ/scm) and V_{actual} and V_{max} are the actual and maximum allowable exhaust gas velocities in m/s, respectively.

If the above requirements are not met, the flare would meet BACT requirements if the following Hydrogen-fueled Operating Specifications were satisfied:

- Non-assisted Flare

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[1] "Should" connotes a *recommendation* from the TNRCC that is not specifically required by law. "Must" refers to something you are *required* to do by laws and regulations.

- Diameter of e inches or greater
- Hydrogen content of 8.0 percent (by volume) on a wet basis or greater as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77
- Exit Velocity ‹ 122fps **and** $V_{max} = (X_{H2} - K_1) * K_2$

Where: V_{max} = maximum permitted velocity, m/sec.
K_1 = Constant, 6.0 volume-percent hydrogen.
K_2 = Constant, 3.9 (m/sec)/volume-percent hydrogen.
X_{H2} = The volume-percent of hydrogen, on a wet basis, as calculated by using the American society for Testing and Materials (ASTM) Method D1946-77. (Incorporated by reference as specified in § 60.17).

These calculations are covered in detail in Chapter 5. The applicant should demonstrate how he will ensure that the waste stream and assist gas stream to the flare will have sufficient net heating value and not exceed the velocity requirements in 40 CFR § 60.18 during all flare operations. These conditions may be ensured with a continuous monitor on the waste stream to the flare to monitor flow rate and heating value or by monitoring other process parameters that have a direct correlation to the flow rate to the flare.

Upset and Maintenance Discharges. Upset and maintenance discharges to flares are also normally expected to meet these requirements. Case-by-case exceptions may be made if the permit applicant provides documentation to demonstrate that this requirement is not appropriate for its flare. This documentation should include the estimated destruction efficiency (based on testing or experience), the frequency and duration of the upset or maintenance discharge, estimated emissions of each air contaminant, and reasons why a larger flare or an emergency flare system is not practical.

High-Velocity Streams. Sonic flares (often handling waste streams with a high hydrogen content) and some vapor combustors and multipoint flares generally do not meet the requirements of 40 CFR § 60.18 under normal operating flow conditions. In these cases, the permit applicant must supply pilot plant test results or other data from the flare manufacturer to justify the claimed destruction efficiency. The required operating conditions and controls (such as waste stream heat content, flame monitoring, temperature monitoring, assist or quench air) should also be specified.

The permit authorizing the flare will include a condition requiring that testing be performed to ensure proper destruction efficiency under routine operating conditions, if possible. The use of sonic and multipoint flares for the control of normal operating emissions will require additional documentation because there is limited publicly available test information, and these flares cannot be easily stack tested to verify the emissions. Requests for variances from these requirements will be considered on a case-by-case basis, provided the proposed control device is not subject to any new source performance standard.

The requirements and basis for the proposed destruction efficiency, NO_x and CO emissions, and control of smoking should be discussed in the permit application. Flare destruction efficiencies are required to be at least 98 percent by weight.

Non-VOC Waste Streams Flares in non-VOC service will be reviewed on a case-by-case basis. Applications for such flares must provide justification guaranteeing smokeless operation, and a demonstration of appropriate tip velocity and waste stream heat content. Waste streams containing significant quantities of ammonia or carbon monoxide generally require more pilots than a VOC stream because these compounds are more difficult to ignite. Technical information should be provided to explain how the flare design and operation will ensure the waste stream is ignited.

Waste Stream Monitoring. An initial flare test is often required. Given the two federal regulations (40 CFR § 60.18 and 40 CFR § 63.11) are technically equivalent, any flare testing required for permit purposes may be done in accordance with 40 CFR § 63.11 rather thatn 40 CFR § 60.18, if flare testing is required by 40 CFR § 63.11. **The option to test per 40 CFR § 63.11 will be stated in the permit requirements.** This will not allow the permit holder to substitute for any flare testing which is required by any federal regulations.

Monitoring of the waste stream routed to the flare may be required to ensure continuing compliance with 40 CFR § 60.18 (BACT) or to as a surrogate continuous emission monitor to ensure continuous compliance with the maximum allowable emission rates. The type of monitoring required will be dependent on the characteristics of the waste stream routed to the flare.

If the waste stream is extremely variable with periods where the net heating value may dip below the required value, a continuous flow monitor and some measurement of the heating value may be necessary. These would serve as inputs into system that added additional natural gas to the waste stream to ensure a sufficient heating value. There may be cases where control might be simplified by assuming that the waste gas has no heating value so that only the flow rate needed to be monitored. Waste streams with consistently high heating value may not require any additional monitoring to ensure proper operation of the flare.

However, such a flare may still require some monitoring to estimate actual emissions. In general, waste stream monitoring may be required when the total flare emissions (summing No_x CO, VOC, and $SO_{2)}$ exceed 100 tons per year. This type of monitoring would normally entail continuous flow monitoring with periodic sampling to determine the waste stream composition. The composition and flow rate data may be used with the appropriate flare factors to determine the emission rate. This method should not be used to demonstrate compliance with the hourly emission rate but may be indicator of process upsets.

Ignition System

All proposed flare systems must employ a continuous pilot ignition system or equivalent. Manual and automatic ignition systems will be considered on a case-by-case basis. An alarm should signal pilot loss, and an automatic reignition system should be in place on process and emergency flares. If the flare is used on a waste stream that may be interrupted—for example, during gasoline loading— the process must be shut down if there is a loss of the pilot flame.

The minimum number of pilots needed is usually most dependent on the actual flare tip diameter. The numbers in Table 2 are typical of permit and amendment applications received in the past by the New Source Review Permits Division of the TNRCC; however, other proposals may be equally acceptable and will be considered on a case-by-case basis:

Table 2. Flare Pilot Requirements

Tip Diameter (in.)	Number of Pilots
2–12	1
14–22	2
24–60	3
60–84	4

Monitoring Flame Integrity

A remote infrared flame monitor is the preferred method of monitoring flame integrity. Thermocouples will be considered, provided an acceptable schedule for replacement is established. For either method, an alarm must signal flame loss.

Liquid Knockout System

An appropriate liquid knockout system should be employed for removing water or condensibles from the waste gas stream before they reach the flare.

Smokeless Design

Routine process and emergency flares should be designed for smokeless operation (no visible emissions except periods not to exceed five minutes in any two-hour period) over the entire range of potential flow rates and must comply with 30 TAC § 111.111. Visible emissions from flare operations can be exempted from the rules and regulations under § 101.11 (General Rules) if the upset and resulting emissions are determined to have been unavoidable. Although emergency flares should operate smokelessly over the entire range of operating conditions using steam injection or
air-assist technology, exceptions may be made for a plantwide power failure where an unavoidable loss of steam or air utilities results. For this case, emissions would be reviewed under § 101.11.

The permit engineer reviewing an applicant's proposed design for a flare system will examine the hydrogen-to-carbon (H/C) ratio of the waste gas stream. Typically, the lower the H/C ratio, the higher the tendency to smoke. For example, waste gas streams composed mostly of olefins, acetylene, and aromatics would more likely be called into question during the technical review than a waste gas stream composed primarily of paraffins.

The reviewing engineer can also be expected to verify that an appropriate supply of assist air is available in the case of air-assist, or that generally no less than 0.4 pounds of steam is supplied per pound of waste gas for H/C ratios less than 0.33. Ratios greater than 1.0 can degrade VOC destruction efficiency and should be avoided. The permit applicant should demonstrate how the proper steam assist ratio will be maintained during flare operations.

BACT for Vapor Oxidizers

The design of these control devices can be considerably more complex than flares. The control efficiency is generally a function of the waste being oxidized; the residence time in the combustion chamber; the temperature of the combustion chamber; oxygen available; and the mixing of the waste, fuel (if needed), and oxygen.

Any changes to the waste stream, residence time, and mixing are usually considered a modification and require permit authorization. Changes to any of these parameters that are not considered a modification under 30 TAC Chapter 116 should be evaluated by the operator closely to ensure that the changes will not impact the existing control efficiency. The oxygen availability and temperature of the combustion chamber can vary during operation, and any stack testing required would be used to set the minimum values for these parameters. The specific requirements for each type of oxidizer are covered in the following subsections of this chapter. Table 3 summarizes these requirements and can be found at the end of this chapter.

A Combustion Unit Table (NSR Table 4, see Attachment D) is required for all vapor oxidizers. The table requires information on waste streams to be combusted, assist fuel, operating temperature, residence time, and exhaust flow rates. It also requires a drawing and description of the oxidizer being permitted. This discussion should also include documentation on control systems such as how sufficient temperature and oxygen are ensured. A measurement of the waste gas flow rate to the unit may be necessary to ensure good control of the assist fuel or combustion air to the unit.

There should usually be no visible emissions from the vapor oxidizer because only vapor streams are combusted in the unit. The vapor oxidizer should be designed to minimize CO and NO_x emissions from the combustion process. NO_x emissions are expected to be 0.10 lb/MMBtu for small units and 0.06 lb/MMBtu for units with
firing rates greater than 40 MMBtu/hr. Combustion of compounds with a high fraction of nitrogen should be examined closely because of the higher level of NO_x emissions (fuel NO_x).

Similarly, oxidation alone may not be appropriate for streams with significant fractions of sulfur (forming SO_2) or halogens (forming the associated acid) in the VOCs to be combusted. Follow-up treatment with an absorber is usually necessary if these types are treated with a vapor oxidizer. The Technical Guidance Package, *Absorption Units*, provides the requirements for these control devices.

This document provides guidance for only for these types of vapor oxidizers at chemical, petrochemical, refining, oil and gas processing, and chemical and petroleum storage facilities.

Thermal Oxidizers

These units are expected to be operated so that a 99.9 percent DRE is achieved for the air contaminant being controlled (VOC in most cases). A lower control efficiency may be allowed if (1) the resulting exhaust gas has a very low VOC concentration (less than 10 ppmv, for example); and (2) the increased oxidizer firing rate necessary to achieve 99.9 percent destruction results in significantly higher NO_x emissions from the unit.

Proper operation of these units is ensured through continuous monitoring of the combustion chamber exhaust temperature, which is generally expected to be at least 1400° F with a residence time of 0.5 to 1 second, although these conditions can vary based on the vapor oxidizer design and compound(s) to be oxidized. The minimum temperature requirement would initially be estimated based on design information with the final minimum temperature verified during the initial stack sampling. An indication of exhaust gas oxygen concentration (typically 2 to 3 percent) is also necessary to ensure proper operation and complete combustion. A CO continuous emission monitoring system (CEMS) can provide additional indication of complete combustion.

Stack sampling for VOC is required to verify proper operation of the unit. Small units that have been previously tested by the manufacturer may not require sampling if the proposed operation (waste stream, residence time, and temperature) has been demonstrated. For most units, an initial stack sample is required for VOC (or the air contaminant being controlled) and CO. Additional sampling would be required if the waste gas contained halogenated compounds (acid gases), compounds containing sulfur (SO_2), or nitrogen (NO_x).

Catalytic Oxidizers

These units are often used to control streams with low net heating value where the catalyst allows for oxidation at lower temperatures, minimizing additional fuel costs as well as NO_x formation. Because the catalyst typically degrades over time, and its effectiveness is dependent on the VOC to be oxidized, additional information is required in the permit application for these units. This information should include:

- Test documentation on the effectiveness of proposed catalyst for the compounds to be treated in the unit.
- The expected lifetime of the catalyst and the basis for this estimate. How will the effectiveness of the catalyst be monitored over its expected life (such as VOC CEMS, periodic stack sampling, or catalyst sampling)? How does the operating temperature affect the life of the catalyst? How is the required operating temperature expected to change?
- How is the catalyst support designed to ensure proper flow through the catalyst bed over the life of the catalyst?
- Poisons or masking agents that the catalyst is susceptible to and whether any of these could potentially be in the waste stream.

The required destruction efficiency allowed is less than for thermal oxidizers, at least 98 percent or an exit concentration of 20 ppmv. Initial sampling is required, and the required minimum operating temperature is set during the initial and follow-up testing. Temperature monitoring is required for all units. Periodic sampling or a VOC CEMS is necessary for larger units to monitor catalyst performance over time; periodic catalyst sampling and testing may be acceptable for smaller units.

Regenerative Oxidizers

These units are generally most cost-effective when used to control lower concentration waste streams (VOC concentration less than 500 ppmv). The low VOC concentration can result in lower control efficiency so that efficiencies of 98 to 99 percent may be acceptable. The required control efficiency might also be specified in terms of VOC outlet concentration (such as 10 ppmv) for dilute waste streams that are difficult to combust.

The permit application should include a discussion on how the oxidizer will maintain (1) the minimum required excess oxygen and (2) the temperature required to achieve the claimed destruction efficiency. These units should have an initial stack test for VOC and CO. The test run should be used to determine the minimum required operating temperature, which is continuously monitored and recorded. The applicant should also provide a method to be used to periodically verify that the inert fill material (usually ceramic) has not settled, become plugged, or degraded. These events may cause a degradation of destruction efficiency even if a constant outlet temperature is maintained. These monitoring requirements may be waived if the applicant agrees to install a VOC CEMS.

These oxidizers should be designed to avoid any spikes in outlet VOC concentration. This result can be achieved by having three or more operating combustion chambers and designing the system so that the chamber last taken off line is vented to the current operating chamber rather than the atmosphere.

Table 3. BACT, Sampling, and Monitoring Guidelines for Vapor Oxidizers

Type	< 2 TPY VOC Emissions	2 to 10 TPY VOC Emissions	> 10 TPY VOC Emissions
thermal	• 99.9% DRE or 10 ppmv • monitor temperature • sample if toxics concern	• 99.9% DRE or 10 ppmv • monitor temperature • sample if toxics concern • monitor excess oxygen • sample VOC, NO_x, and oxygen	• 99.9% DRE or 10 ppmv • monitor temperature • sample if toxics concern • monitor excess oxygen • sample VOC, NO_x, and oxygen • CO CEMS • VOC CEMS if toxics concern
catalytic	• 98% DRE or 20 ppmv • monitor temperature • sample VOC	• 98% DRE or 20 ppmv • monitor temperature • VOC CEMS, sampling equivalent, or catalyst monitoring • sample VOC, CO and NO_x	• 98% DRE or 20 ppmv • monitor temperature • VOC CEMS, sampling equivalent, or catalyst monitoring • sample VOC, CO and NO_x
regenerative	• 98 to 99% DRE or 10 ppmv • monitor temperature • sample VOC and CO • monitor ceramic	• 98 to 99% DRE or 10 ppmv • monitor temperature • sample VOC and CO • monitor ceramic • sample NO_x	• 98 to 99% DRE or 10 ppmv • monitor temperature • sample VOC and CO • monitor ceramic • sample NO_x

Additional compounds may be added to the sampling lists if warranted. This might occur if acid formation is expected as a result of combusting a halogenated compound or if there are health effects concerns for a particular compound.

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Chapter 5—Emission Factors, Efficiencies, and Calculations

This chapter provides detailed instructions for the calculations necessary to verify BACT and estimate emissions from flares and vapor oxidizers. Flares must be checked to determine whether they will satisfy the flow and thermal requirements of 40 CFR § 60.18, and their emissions are determined by the use of emission factors. Example calculations are provided for these flare calculations.

Oxidizer emissions are determined by using previous sampling results or emission factors from the manufacturer or AP-42. These calculations are very similar to the flare calculations and are only discussed in general terms.

Flares: Introduction

Although emissions from emergency flares are not included in a permit when it is issued, emissions should be estimated for both routine process flares and emergency flares. Sometimes, emissions of routine pilot gas combustion may be included in an issued permit for emergency flares (although not required).

In this section, the *flare* emission factors and destruction efficiencies are presented first. This information is followed by sample *calculations* that demonstrate how to ensure that the requirements of 40 CFR § 60.18 are satisfied and how to estimate emissions from a flare. Flare data in Attachment B (typical refinery flare) will be used as a basis in most of the following calculations. Flare data in Attachment C (acid gas flare) will be used as a basis in the example calculations for SO_2 emissions.

Flare Emission Factors

The usual flare destruction efficiencies and emission factors are provided in Table 4. The high-Btu waste streams referred to in the table have a heating value greater than 1,000 Btu/scf.

Flare Destruction Efficiencies

Claims for destruction efficiencies greater than those listed in Table 4 will be considered on a case-by-case basis. The applicant may make one of the three following demonstrations to justify the higher destruction efficiency: (1) general method, (2) 99.5 percent justification, or (3) flare stack sampling.

Table 4. Flare Factors

Waste Stream	**Destruction/Removal Efficiency (DRE)**		
VOC	98 percent (generic) 99 percent for compounds containing no more than 3 carbons that contain no elements other than carbon and hydrogen in addition to the following compounds: methanol, ethanol, propanol, ethylene oxide and propylene oxide		
H_2S	98 percent		
NH_3	case by case		
CO	case by case		
Air Contaminants	**Emission Factors**		
thermal NO_x	steam-assist:	high Btu	0.0485 lb/MMBtu
		low Btu	0.068 lb/MMBtu
	other:	high Btu	0.138 lb/MMBtu
		low Btu	0.0641 lb/MMBtu
fuel NO_x	NO_x is 0.5 wt percent of inlet NH_3, other fuels case by case		
CO	steam-assist:	high Btu	0.3503 lb/MMBtu
		low Btu	0.3465 lb/MMBtu
	other:	high Btu	0.2755 lb/MMBtu
		low Btu	0.5496 lb/MMBtu
PM	none, required to be smokeless		
SO_2	100 percent S in fuel to SO_2		

*The only exeption ot this is if inorganics might be emitted from the flare. In the case of landfills, the AP-42 PM factor may be used. In other cases, the emissions should be based on the composition of the waste stream routed to the flare.

Method 1: General

Provide sampling results for the flare proposed when flaring a waste stream similar to that expected at the flare being permitted. The following concerns should be addressed in using test results from other flares:

1. Sampling methods must be approved by the TNRCC.

2. The applicant should determine the indicated operating parameters of flares (and streams directed to them) for which greater than standard destruction efficiencies (> SDE) are claimed. The determinations should indicate the maximum or minimum values required for flare performance at the claimed efficiency. The determinations should be made during the testing protocols used to demonstrate > SDE and should include waste stream composition, tip velocities, and heating values.

3. The applicant should install, calibrate, operate, and maintain a flow meter to monitor actual stream flow rates to, and calculate tip velocities of, flares for which > SDE are claimed. The applicant should maintain records that indicate on a continuous basis the flow rates and heating values of the streams directed to the flares for which > SDE are claimed.

4. Flow rates of streams to flares for which > SDE are claimed must not exceed the lesser of (a) flow rates that produce the tip velocities specified in 40 CFR § 60.18, or (b) flow rates and tip velocities demonstrated during testing to correspond to the flare efficiency claimed.

5. Heating values of streams directed to flares for which > SDE are claimed must be no less than (a) 300 Btu/scf for streams directed to nonassisted flares and 400 Btu/scf for streams directed to assisted flares, and (b) heating values demonstrated during testing to correspond to the flare efficiency claimed.

6. The applicant must provide vendor data supporting the claimed flare efficiency.

Method 2: 99.5 Percent Justification

A 99.5 percent flare VOC destruction/removal efficiency (DRE) may be claimed if the permit engineer is satisfied that the permit applicant has provided the following information:

- Documentation that the VOC compounds in the waste stream are not difficult to combust (they are easy to combust and can be approximated by the propane/propylene streams in the Chemical Manufacturers Association [CMA]/EPA flare tests used to derive the 99.5 percent DRE). This demonstration may be satisfied by comparison testing at equivalent operating conditions, vendor support of the proposed destruction efficiency, or by using other parameters such as flame stability curves. Some compounds are identified as being difficult to combust, such as cyanides and some halogenated hydrocarbons, and will not be allowed 99.5 percent DRE.

- Documentation that the waste stream composition does not vary excessively in volumetric flow rate, composition, or heating value over short periods. For example, emissions routed from single bay truck loading may vary too much to allow a 99.5 percent DRE. This requirement approximates the steady-state operation of the flares tested in the CMA/EPA flare tests.

- Demonstrate that the waste stream to the flare will meet the flow and heating value requirements of 40 CFR § 60.18 during all operating conditions. The preferred method would be constantly to monitor the waste stream flow rate and Btu content. Applicants may propose alternate methods of monitoring to ensure these requirements are met. (This information must be provided with all flare applications, regardless of the DRE proposed.)

If the 99.5 percent DRE is claimed by the applicant and accepted by the permit engineer, the revised CO and NO_x emission factors in Table 5 must be used to determine those emissions.

Table 5. 99.5 Percent DRE Flare Factors

Air Contaminants	**Emission Factors**	
thermal NO_x	steam-assisted:	0.05 lb/MMBtu
	other: high Btu	0.17 lb/MMBtu
	low Btu	0.084 lb/MMBtu
CO	0.26 lb/MMBtu	

Method 3: Flare Stack Sampling

A destruction efficiency of greater than 98 percent (or equivalent) may be claimed for an enclosed flare/vapor combustor if the following conditions are satisfied:

- The applicant provides technical information that justifies the claimed destruction efficiency for the proposed flare and waste stream under all operating conditions. This justification may be based on test results from similar facilities and waste streams or based on other testing.

- The flare design must allow for stack testing of the operating flare per TNRCC guidance (*TNRCC Sampling Manual* or approved waiver). The flare should be tested as necessary to verify the claimed control efficiency under routine operating conditions.
- The required operating range for the destruction efficiency claimed must be identified, and a control system should be in place to ensure that the flare is operated within the specified operating limits to ensure optimum combustion. Temperature monitoring may be required if the claimed destruction efficiency is in excess of 99 percent.

CO and NO_x emissions from these flares may be estimated based on previous test results or manufacturers' estimates; stack sampling for these pollutants may be required if the estimate varies significantly from the flare factors presented in Table 4. The applicant may state the destruction efficiency for an enclosed flare used to control emissions from liquid loading operations in terms of mass VOC emitted/volume liquid loaded if a reasonable estimate of maximum hourly emissions is also provided.

DREs for Other Waste Streams

Destruction efficiencies for other waste streams (CO, ammonia, or H_2S for example) will be considered on a case-by-case basis. The applicant may compare the use of its flare to available test data (in a manner similar to that described for VOC in Method 2 above) to estimate destruction efficiency.

Sample Calculations

Emission Calculations

The flare destruction efficiencies and emission factors are used in the sample calculations that follow. Assuming an ideal gas mixture, use the ideal gas law to convert the volumetric flow rates from Attachment B and Table 6 into mass flow rates. The values are shown in Table 7.

$$m = \frac{60(MW)PV}{RT}$$

where m = mass flow rate in lb. per hour,
MW = molecular weight in lb. per lbmole,
P = standard pressure = 14.7 psia,
V = flow rate in scfm,
R = gas constant = 10.73 $\text{psia}\cdot\text{ft}^3\cdot\text{lbmol}^{-1}\cdot{}^\circ\text{R}^{-1}$, and
T = standard temperature = 528°R.

Table 6. Waste Stream Constituents in Mole Percent

Constituent	Average Case		Maximum Case	
	scfm	mole %	scfm	mole %
Butane	10.16	5.08	12.70	5.08
Propylene	5.94	2.97	7.43	2.97
Propane	5.08	2.54	6.35	2.54
Ethylene	84.74	42.37	105.93	42.37
Ethane	37.28	18.64	46.60	18.64
Hydrogen	22.04	11.02	27.55	11.02
Ammonia	4.24	2.12	5.30	2.12
Inerts	30.50	15.26	38.13	15.26
Totals	200.00	100.00	250.00	100.00

Table 7. Estimation of Average Mass Flow Rates

Constituent	scfm	MW	lb/hr
Butane	10.16	58.12	91.91
Propylene	5.94	42.08	38.91
Propane	5.08	44.09	34.86
Ethylene	84.74	28.05	369.95
Ethane	37.28	30.07	174.47
Hydrogen	22.04	2.02	6.92
Ammonia	4.24	17.03	11.24

Waste Stream DRE. Applying 98 percent destruction efficiency for butane+ and hydrogen, and 99 percent destruction efficiency for propylene, propane, ethylene, and ammonia, the hourly maximum and annual emission rates may then be estimated (Table 8). The hourly emissions are calculated using the maximum case flow rate, which is 25 percent greater than the average case. Note that the ethane and hydrogen emission rates need not be shown on the NSR Table 1(a) submitted with the permit application, since these emissions are not regulated as pollutants.

Table 8. Emission Rates

Constituent	lb/hr	TPY
Butane	2.30	8.0
Propylene	0.49	1.7
Propane	0.44	1.5
Ethylene	4.63	16.3
Ethane	2.11	7.6
Hydrogen	0.18	0.6
Ammonia	0.14	0.5

NO_x and CO Emissions. The mole percent of each constituent in the waste stream may be calculated for both the average and maximum scenarios by dividing the individual flow rates by the total flow rates and multiplying by 100 percent (Table 6). In this case, the calculations are simplified since the average and maximum case waste streams have the same compositions. If they were of different composition, the heating value calculations would be required for both cases. Note that the maximum case shows the maximum vent stream to the flare under normal operating conditions for calculating emissions from the flare (upset and maintenance conditions are not considered). Emergency and maintenance emissions are not directed to the example flare.

Next, estimate the net, or lower, heating value of the waste stream by assuming a basis of 1 scf. Heats of combustion for most compounds may be found in any common engineering reference book. The net heat release will be used in determining which NO_x and CO factors to use as well as verifying that the flare will meet the minimum heating value requirements of 40 CFR § 60.18.

Based on the overall net heat release (see Table 9), it is now evident that the NO_x and CO factors for high-Btu, air-assisted flares should be used. Using these factors:

(0.138 lb. NO_x/MMBtu)(1228E-6 MMBtu/scf)(250 scf/min)(60 min/hr)
= **2.54 lb. NO_x/hr**;

(0.138 lb. NO_x/MMBtu)(1228E-6 MMBtu/scf)(200 scf/min)(ton/2000 lb.)
× (60 min/hr)(8760 hr/yr)
= **8.91 tons NO_x per year.**

(0.2755 lb. CO/MMBtu)(1228E-6 MMBtu/scf)(250 scf/min)(60 min/hr)
= **5.07 lb. CO/hr**;

(0.2755 lb. CO/MMBtu)(1228E-6 MMBtu/scf)(200 scf/min)(ton/2000 lb.)
× (60 min/hr)(8760 hr/yr)
= **17.78 tons CO per year.**

Table 9. Estimation of Net Heat Releases

Constituents	scf	Net Heating Value Btu/scf	Net Heat Release Btu/scf
Butane	0.0508	2956	150
Propylene	0.0297	2142	64
Propane	0.0254	2272	58
Ethylene	0.4237	1471	623
Ethane	0.1864	1587	296
Hydrogen	0.1102	269	30
Ammonia	0.0212	352	7
Inerts	0.1526	0	0
Totals	1.0000		1228

The NO_x emissions also need to be corrected for the fuel NO_x from ammonia. In this case, 11.2 lb. ammonia/hr(0.005)(250/200) = **0.08 lb/hr** NO_x. This results in total NO_x emissions of 2.62 lb/hr and 9.15 tons per year.

Particulate Emissions. Particulate emissions should be negligible and should therefore not be estimated, since smoking flares are excluded from permitting as defined in 30 TAC Section 111.111. There may be cases where there are noncombustible elements (such as metals) associated with the VOC being combusted. If this is the case, these emissions should be estimated based on sampling results from the waste stream. The AP-42 landfill flare particulate matter factor may be used if the flare controls landfill gas.

The following sample calculation demonstrates how to handle waste streams with hydrogen sulfide.

H_2s Emissions. For instances where a waste stream to a flare contains H_2S, assume that 100 percent by weight of H_2S is converted to SO_2 (the H_2S allowable DRE is 98 percent but actual flare operation could combust almost 100 percent of the waste stream). Referring to Attachment C, convert the design maximum H_2S volumetric waste flow rate into a molar flow rate using the ideal gas law:

$$\frac{(4.5\,ft^3/\text{min})(14.7\,psia)(60\,\text{min}/hr)}{(10.73\ psia{\cdot}ft^3/lbmol/°R\ )(528°R\ )} = 0.701\ lbmol\ H_2S/hr$$

One mole of H_2S will form one mole of SO_2:

$$\frac{(0.701\ lbmol\ H_2S/hr)(1\ lbmol\ SO_2/lbmol\ H_2S)}{(1\ lbmol\ SO_2/64\ lb)} = 44.9\ lb\ SO_2/hr$$

and as much as 2 percent of the H_2S will remain:

$$(0.02)(0.701\ \text{lbmol}\ H_2S/\text{hr})(34\ \text{lb.}\ H_2S/\text{lbmol}) = \mathbf{0.48\ lb\ H_2S/hr}$$

Calculations for annual emissions should be performed in a similar manner using the average H_2S flow rate of 3.5 scfm, resulting in 0.55 lbmol H_2S/hr, and 34.9 lb. SO_2/hr. The annual SO_2 emissions should then be estimated on a TPY basis:

$(34.9 \text{ lb/hr})(1 \text{ ton}/2{,}000 \text{ lb.})(24 \text{ hr/d})(365 \text{ d/yr}) = \mathbf{152.7\ TPY\ SO_2}$,

and, likewise, 2 percent of the H_2S will remain:

$(0.02)(0.545)(34)(24)(365)/2{,}000 = \mathbf{1.62\ TPY\ H_2S}$

40 CFR 60.18 BACT Check

Calculations should also be performed to ensure the proposed flare meets BACT requirements of 40 CFR § 60.18 . It was noted that H_T = 1,228 Btu/scf (Table 9) is greater than the minimum heating value of 300 Btu/scf required for air-assisted flares according to 40 CFR § 60.18(c)(3); therefore, this flare would be in compliance. In accordance with 60.18(5), air-assisted flares designed for and operated with an exit velocity less than the value V_{max} as calculated below, and less than 122 m/s (400 ft/s) are allowed. For this flare:

$$V_{max} = 8.706 + 0.7084H_T = 8.706 + 0.7084(43.3) = \mathbf{39.4\ m/s}$$

The actual flare tip velocity may then be calculated for comparison using the design maximum flow rate and the flare tip area based on the flare tip diameter:

$$V_{actual} = Q/A$$

where Q = volumetric flow rate, ft^3/min, and
A = flare tip area, ft^2

$$V_{actual} = (250\ ft^3/min)(4/3.1416/1^2\ ft^{-2})(1\ min/60\ s)(0.3048\ m/ft)$$
$$= \mathbf{1.62\ m/s}$$

So, the sample flare meets the flare tip velocity restrictions of 40 CFR § 60.18.

40 CFR § 60.18 BACT Check for Hydrogen Flares

Similar to the previous example, calculations should also be performed to ensure a proposed hydrogen flare meets the BACT requirements of 40 CFR § 60.18. The heating value is calculated in the same manner as the above example. The flare diameter must be greater than 3 inches, the hydrogen content must be greater than 8.0 percent by volume and the exit velocity, V_{max}, less than 37.2 m/s (122ft/s) as calculated below. For example, a stream with a 11.0 percent hydrogen volume on a wet basis the maximum velocity would be:

$$V_{max} = (X_{H2} - K_1) * K_2 = (11.0 - 6.0) * 3.9 = 19.5 \text{ m/s } (64.0 \text{ ft/s})$$

So, the sample hydrogen flare would meet the flare tip velocity requirements of 40 CFR § 60.18.

Modeling Calculations

The net heating value of the waste gas stream to the flare and the flare height is sufficient information for the reviewing engineer to perform initial screen modeling using the EPA Screen 3 model with the built-in flare source algorithm; however, additional calculations must be provided to the reviewing engineer if refined modeling using the EPA ISC series of models and the point source algorithm is required. It should be noted that refined modeling is the applicant's responsibility and may be requested as determined to be appropriate by the reviewing engineer.

Flares are considered a special type of elevated source that may be modeled as a point source. In a flare, the velocity of the waste stream and the flare temperature are not used to determine the plume rise; rather, the TNRCC suggests use of the parameters and formula explained below to calculate the effective stack diameter based upon the net heat release and the average molecular weight of the compounds being burned.

If a flare is to be treated as a point source, accurate determination of all stack parameters is not possible. Since combustion occurs at or beyond the flare tip in the atmosphere, appropriate values for stack exit temperature and exit velocity cannot be accurately determined. The diameter of the pipe leading to the flare tip is not a factor in determining plume rise. The point source algorithm can be used with arbitrary values assigned for stack exit velocity (20 m/s or 66 fps) and temperature (1,273K or 1,831°F) to predict dispersion for flare type sources.

A stack height equal to the height of the flare tip is recommended for flares. The effective flare tip diameter is determined using the following equation:

$$D = \sqrt{10^{-6}\, q(1 - 0.048\sqrt{MW})}$$

where D = effective flare tip diameter, meters,
q = net or lower heat release, cal/sec, and
MW = volume average molecular weight, g/g-mole.

First, estimate the net heat release based upon the overall net heating value from Table 9 and maximum waste gas stream flow rate from Table 6:

$$q = (1{,}228 \text{ Btu/scf})(250 \text{ scf/min})(1 \text{ min}/60 \text{ s})(252 \text{ cal/Btu})$$
$$= \mathbf{1{,}289{,}400\ cal/sec}$$

Next, estimate the volume average molecular weight based upon the maximum volumetric flow rate (Table 6) and the molecular weights of the individual constituents (Table 10). Finally, estimate the effective flare tip diameter based on the net heat release and average molecular weight:

$$D = [(10^{-6})(1{,}289{,}400)(1-0.048(27.61)^{0.5})]^{0.5} = 0.982 \text{ m} = \mathbf{3.22\ ft}.$$

Enclosed vapor combustion units should not be modeled with the above parameters, but instead with stack parameters that reflect the physical characteristics of the process unit.

Table 10: Estimation of Volume Average Molecular Weight

Constituent	scfm	Mole fraction	MW	MFxMW
Butane	10.16	0.060	58.12	3.49
Propylene	5.94	0.035	42.08	1.47
Propane	5.08	0.030	44.09	1.32
Ethylene	84.74	0.500	28.05	14.02
Ethane	37.28	0.220	30.07	6.62
Hydrogen	22.04	0.130	2.016	0.26
Ammonia	4.24	0.025	17.03	0.43
Totals		1.0000		27.61

Vapor Oxidizers

The methods used to determine emissions from oxidizers are very similar to those in the flare examples, but the emission factors used are different. Because the calculational methods are the same as those used in the flare examples, they will not be duplicated here. Hourly emissions are based on the maximum expected hourly emission rate during routine operations (does not include startups, shutdowns, or upsets), while the annual emissions are based on the annual operating rate. The preferred methods and emission factors for each type of air contaminant are described in the following paragraphs.

VOC. Calculate the emissions based on the waste gas to the oxidizer and the control efficiency (if a large amount of assist fuel is used, the EPA AP-42 natural gas boiler VOC emission factor may be used to determine VOC due to the incomplete combustion of natural gas). The exhaust molar flow rate and the maximum ppmv and VOC molecular weight should be used if BACT review is based on the outlet concentration.

SO_2. Assume 100 percent of the sulfur present in the waste and assist gas is oxidized to SO_2.

Halogens. Assume 100 percent conversion to corresponding acid. If more than a small fraction of halogen is expected in the waste gas being treated, a vendor estimate should be used to determine fraction of acid and gas (HCl and Cl_2, for example).

Products of Combustion. CO, NO_x, and particulate emissions should be determined based on vendor estimates if the information is available. The NO_x emissions are generally expected to be less than 0.10 lb/MMBtu (0.06 lb/MMBtu if firing rate greater than 40 MMBtu/hr), and CO exhaust concentrations are generally less than 100 ppmv. The applicant will need to provide the calculation basis for any NO_x emission expected as a result of nitrogen found in the VOC being combusted. Particulate emissions are expected to be similar to those from gas fired boilers, and the appropriate factor from AP-42 may be used to estimate emissions.

Chapter 6 Example Permit Conditions

The special conditions in this chapter are examples only. These conditions are typical of those required for most permits. Additional permit special conditions may be required by the permit engineer to address specific permit requirements and operating conditions. The words in italics in the example conditions are included to present possible variations in the permit conditions for specific cases. The conditions are grouped into the following categories: general, flares, enclosed flares or vapor oxidizers, and vapor oxidizers.

General

1. All waste gas from point sources containing VOCs and/or other organic compounds (hydrocarbons and/or hydrocarbon derivatives excluding carbon dioxide) shall be routed to a flare or a thermal oxidizer.[1] The flare shall operate with no less than 98 percent efficiency, and the thermal oxidizer shall operate with no less than 99.9 percent efficiency in disposing of the carbon compounds captured by the collection system. The waste gas streams shall include process vents, relief valves, analyzer vents, steam jet exhausts, upset emissions, start-up and shutdown-related emissions or purges, blowdowns, or other system emissions of waste gas. Storage tank vents, cooling tower exhaust, and process fugitive emissions are excluded from this requirement. Any other exception to this provision requires prior review and approval by the executive director, and such exceptions may be subject to strict monitoring requirements.

2. Fuel gas combusted at this facility shall be sweet natural gas containing no more than five grains of total sulfur per 100 dry standard cubic feet.

Flares

3. Flares shall be designed and operated in accordance with the following requirements:

   A. The combined natural gas and waste stream to the flare tip shall meet the 40 CFR § 60.18 specifications for minimum net heating value and maximum tip velocity under normal, upset, and maintenance flow conditions. Compliance with this condition shall be demonstrated by the monitoring required in section D below. Flare testing per 40 CFR § 60.18(f) may be requested by the TNRCC regional office to demonstrate compliance with this condition. *Flare testing per 40 CFR § 63.11 (b) may be substituted to satisfy this permit requirement if flare testing per 40 CFR § 63.11 is required by any federal regulation.*

   B. The flare shall be operated with a flame present at all times and have a constant pilot flame *(electric ignition may be allowable on a case-by-case basis)*. The pilot flame shall be monitored by a thermocouple or an infrared monitor.

   C. The flare shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours. *(As applicable)* Such operation shall be ensured by the use of steam *(or air)* assist to the flare. The

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[1] In Chapter 6, the word ***"shall"*** is used to mean the same thing as "must" in the preceding chapters—something ***required*** by laws or regulations. The reason for the variation is that Chapter 6 contains examples from statements of special conditions in current use by the TNRCC.

permit holder shall ensure proper operation of the steam *(or air)* assist through monitoring as required by section D below.

D. The holder of this permit shall install a continuous flow monitor and an analyzer that provide a record of the vent stream flow and composition (total VOC *or Btu content*) to the flare. The flow monitor sensor and analyzer sample points should be installed in the vent stream as near as possible to the flare inlet such that the total vent stream to the flare is measured and analyzed. The average hourly values of the flow and composition shall be recorded. Records of the hourly averages shall be maintained for two years and be made available to the executive director of the TNRCC upon request. *(This section may be replaced by specifying other process parameters identified by the permit applicant during the review process that will ensure there will always be sufficient heat content for any waste stream velocity and that there will be proper steam or air assist to prevent smoking but not affect flare destruction efficiency.) The condition may also be structured to provide for emission monitoring with a flow monitor and periodic sampling if there are significant emissions from the flare).*

Enclosed Flares or Vapor Oxidizers

4. Sampling ports and platform(s) shall be incorporated into the design of the vapor recovery unit stack according to the specifications set forth in the attachment entitled "Chapter 2, Stack Sampling Facilities" *[attachment provided with permit conditions]*. Alternate sampling facility designs may be submitted for approval by the TNRCC regional manager or the manager of the Office of Air Quality Enforcement Division, Engineering Services Section.

5. The holder of this permit shall perform stack sampling and other testing as required to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the vapor oxidizer *(or enclosed flare)*. The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense.

   A. The appropriate TNRCC regional office in the region where the source is located shall be contacted as soon as testing is scheduled, but not less than 45 days prior to sampling to schedule a pretest meeting.
   The notice shall include:

   (1) date for pretest meeting,
   (2) date sampling will occur,
   (3) name of firm conducting sampling,

(4) type of sampling equipment to be used, and
(5) method or procedure to be used in sampling.

The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for submitting the test reports.

A written proposed description of any deviation from sampling procedures specified in permit provisions or TNRCC or Environmental Protection Agency (EPA) sampling procedures shall be made available to the TNRCC prior to the pretest meeting. The regional manager or the manager of the Source and Mobile Monitoring Section shall approve or disapprove of any deviation from specified sampling procedures.

Requests to waive testing for any pollutant specified in Section B of this condition shall be submitted to the TNRCC Office of Air Quality, New Source Review Permits Division. Test waivers and alternate/equivalent procedure proposals for New Source Performance Standard (NSPS) testing, which must have EPA approval, shall be submitted to the TNRCC Source and Mobile Monitoring Section in Austin.

B. Air contaminants emitted from the enclosed flare *(or oxidizer)* to be tested for include (but are not limited to) VOC *(and CO and* NO_x *for vapor oxidizers).*

C. Sampling shall occur within 60 days after initial start-up of the facilities and at such other times as may be required by the executive director of the TNRCC. Requests for additional time to perform sampling shall be submitted to the regional office. Additional time to comply with the applicable requirements of 40 CFR Part 60 and 40 CFR Part 61 requires EPA approval, and requests shall be submitted to the TNRCC Source and Mobile Monitoring Section in Austin.

D. The plant shall operate at maximum production *(or loading)* rates during stack emission testing. Primary operating parameters that enable determination of production rate *(or loading rate)* and combustor operating parameters shall be monitored and recorded during the stack test. These parameters are to be determined at the pretest meeting. If the plant is unable to operate at maximum rates during testing, then future production *(or loading)* rates may be limited to the rates established during testing. Additional stack testing may be required when higher production rates are achieved. The combustor operating parameters during testing shall be used to set the normal operating conditions until the next stack test is performed.

E. Three copies of the final sampling report shall be forwarded to the TNRCC within 30 days after sampling is completed. Sampling reports shall comply with the attached provisions of Chapter 14 of the TNRCC *Sampling Procedures Manual [attached to permit conditions]*. The reports shall be distributed as follows:

- one copy to the TNRCC regional office;
- one copy to the local air pollution control program; and
- one copy to the TNRCC Austin Air Quality Enforcement Division, Engineering Services Section.

F. Stack sampling for VOC shall be repeated annually in accordance with sections A, B, and D above (for catalytic oxidizers).

Vapor Oxidizers

6. The oxidizer firebox exit temperature shall be continuously monitored and recorded. The vapor oxidizer firebox exit temperature *(of the second combustion chamber)* shall be maintained at not less than 1400°F while waste gas is being fed into the oxidizer prior to initial stack testing. The minimum temperature shall be at least that maintained during the most recent stack testing required by Special Condition No. 5 after initial stack testing has been completed.

The exit temperature of the stand-by oxidizer firebox shall be maintained at not less than 800°F.

7. The oxidizer excess oxygen shall be continuously monitored, recorded, and maintained at least at the level during the stack testing required by Special Condition No. 5.

8. The holder of this permit shall install, calibrate, maintain, and operate a CEMS to measure and record the concentration of VOC in the catalytic oxidizer exhaust stack (EPN #).

A. Each CEMS shall meet the design and performance specifications, pass the field tests, meet the installation requirements, data analysis, and reporting requirements specified in Performance Specifications No. 1 through 7, 40 CFR Part 60, Appendix B. If there are no applicable performance specifications in 40 CFR Part 60, Appendix B, contact the TNRCC Air Quality Enforcement Division, Engineering Services Section, for requirements to be met. Written copies of the performance test results shall be submitted within 60 days of testing completion to the TNRCC Regional Office and TNRCC Air Quality Enforcement Division, Engineering Services Section.

B. The system shall be spanned daily excluding weekends and holidays and corrective action taken when the span drift exceeds two times the amounts specified in 40 CFR Part 60, Appendix B. Span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days, unless the monitor is required by a Subpart of NSPS or National Emission Standard for Hazardous Air Pollutants (NESHAPS), in which case span shall be done daily without exception. The monitor shall have a cylinder gas audit (CGA) performed at least quarterly. The procedures followed during the CGA shall comply with the requirements of 40 CFR Part 60, Appendix F, Procedure 1, Section 5.1.2. For non-NSPS sources, an equivalent method approved by the TNRCC may be used.

C. The CEMS monitoring data will be reduced to hourly average concentrations at least once every week, using a minimum of four equally spaced data points from each one-hour period. At least 23 hourly averages shall be generated per day. Flow rates used to convert ppmvd to mass emission rates in pounds per hour may be obtained from calculations based on the oxidizer's exhaust stack flow rate and firing rate. The individual average concentrations shall be reduced to units of the permit allowable emission rate in pounds per hour at least once every week, *demonstrating compliance with Special Condition No.#.*

D. This condition does not preempt the reporting requirement of the TNRCC General Rules, Sections 101.6 and 101.7, pertaining to process upsets and maintenance.

E. During all periods of operation when the VOC CEMS is out of service, the oxidizer operation shall be based on the firebox exit temperature.

F. All cylinder gas exceedances of ±15 percent accuracy and any unscheduled CEMS downtime not corrected within 24 hours shall be reported to the TNRCC regional manager, and necessary corrective action shall be taken. Unscheduled CEMS downtime is any CEMS downtime not required for daily span checks and annual relative accuracy test audits. Supplemental stack concentration measurements may be required at the discretion of the TNRCC regional manager.

G. For NSPS sources subject to Appendix F, the TNRCC regional office shall be notified at least 30 days prior to each annual relative accuracy testing audit in order to provide them the opportunity to observe the testing.

9. Application-specific condition directing any required catalyst testing and monitoring or ceramic monitoring.

References

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Perry's Chemical Engineers' Handbook, Sixth Edition. Perry, Robert H. and Green, Don, McGraw-Hill, New York, 1984.

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Glossary

BACT—best available control technology

BIF—boiler, incinerator, and furnace

Btu—British thermal unit

CEMS—continuous emission monitoring system

CFR—Code of Federal Regulations

DRE—destruction/removal efficiency

MJ—megajoules

MMBtu—million Btu

NSRPD—New Source Review Permits Division

ppmv—parts per million by volume

RCRA—Resource Conservation and Recovery Act

scf—standard cubic foot

VOC—volatile organic compound as defined in 30 TAC Section 115

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Attachment A—General Control Device Requirements, 40 CFR § 60.18

(a) Introduction. This section contains requirements for control devices used to comply with applicable Subparts of parts 60 and 61. The requirements are placed here for administrative convenience and only apply to facilities covered by Subparts referring to this section.

(b) Flares. Paragraphs (c) through (f) apply to flares.

(c)(1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except periods not to exceed a total of five minutes during any two consecutive hours.

(2) Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f).

(3) An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(3)(i) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.

Flares shall be used that have a diameter of 3 inches or greater, are nonassisted have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 37.2 m/s (122 ft/sec) and less than the velocity, V_{max}, as determined by the following equation:

$$V_{max} = (X_{H2} - K_{1}) * K_2$$

Where:

V_{max} =maximum permitted velocity, m/sec.

K_1 = Constant, 6.0 volume-percent hydrogen.

K_2 = The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77. (Incorporated by reference as specified in § 60.17).

Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section.

(4) Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (b)(4) (ii) and (iii).

Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).

Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(5), and less than 122 m/sec (400 ft/sec) are allowed.

(5) Air-assisted flares shall be designed and operated with an exit velocity less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(6).

(6) Flares used to comply with this section shall be steam-assisted, air-assisted, or nonassisted.

Owners or operators of flares used to comply with the provisions of this Subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable Subparts will provide provisions stating how owners or operators of flares shall monitor these control devices.

Flares used to comply with provisions of this Subpart shall be operated at all times when emissions may be vented to them.

Reference method 22 shall be used to determine the compliance of flares with the visible emission provisions of this Subpart. The observation period is two hours and shall be used according to method 22.

The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

where: H_T = Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but standard temperature for determining the volume corresponding to one mole is 20 °C;

$$K = 1.740x10^{-7} \left(\frac{1}{ppm}\right) \left(\frac{gmol}{scm}\right) \left(\frac{MJ}{kcal}\right)$$

where the standard temperature for

$$\left(\frac{gmole}{scm}\right) \text{ is } 20°\text{C};$$

C_i = Concentration of sample component I in ppm on a wet basis, as measured for organics by reference method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 (incorporated by reference as specified in §60.17); and

H_i = Net heat of combustion of sample component I, kcal/g mole at 25 °C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382-76 (incorporated by reference as specified in § 60.17) if published values are not available or cannot be calculated.

The actual exit velocity of a flare shall be determined by dividing the volumetric flow rate (in units of standard temperature and pressure), as determined by reference methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip.

The maximum permitted velocity, V_{max}, for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation.

$$\text{Log}_{10} (V_{max})=(H_T+28.8)/31.7$$

V_{max} = Maximum permitted velocity, M/sec
28.8 = Constant
31.7 = Constant
H_T = The net heating value as determined in paragraph (f)(3).

The maximum permitted velocity, V_{max}, for air-assisted flares shall be determined by the following equation.

$$V_{max}=8.706+0.7084 (H_T)$$

V_{max} = Maximum permitted velocity, m/sec
8.706 = Constant
0.7084 = Constant

H_T = The net heating value as determined in paragraph (f)(3).

[51 FR 2701, Jan. 21, 1986]

Attachment B—Typical Refinery Flare Data
(from NSR Table 8, Flare Systems)

TABLE 8. FLARE SYSTEMS

Number from Flow Diagram	Manufacturer & Model No. (if available)
1 (Refinery Flare)	N/A

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Max.
		(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])
	1. Butane+		10.16	12.70
	2. Propylene		5.94	7.43
	3. Propane		5.08	6.35
	4. Ethylene		84.74	105.93
	5. Ethane		37.28	46.60
	6. H_2		22.04	27.55
	7. NH_3		4.24	5.30
	8. Inerts		30.50	38.13
% of time this condition occurs		5	80	15

	Flow Rate (scfm [68°F, 14.7 psia])		Temp. °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	200	250	130	0
Fuel Added to Gas Steam		0.5	110	0

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [68°F & 14.7 psia]) per pilot
	1	Natural Gas	0.5

For Stream Injection	Stream Pressure (psig)		Total Stream Flow Rate (lb/hr)	Temp. °F	Velocity (ft/sec)
	Min. Expected	Design Max.			
	Number of Jet Streams	Diameter of Steam Jets (inches)	Design basis for steam injected (lb steam/lb hydrocarbon)		

For Water Injection	Water Pressure (psig) Min. Expected Design Max.	Total Water Flow Rate (gpm) Min. Expected Design Max.	No. of Water Jets	Diameter of Water Jets (inches)

Flare Height (ft) 60	Flare tip inside diameter (ft) 1
Capital Installed Cost $20,000	Annual Operating Cost $15,000

Supply an assembly drawing, dimensioned and to scale, to show clearly the operation of the flare system. Show interior dimensions and features of the equipment necessary to calculate its performance. Also describe the type of ignition system and its method of operation. Provide an explanation of the control system for steam flow rate and other operating variables.

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Attachment C—Typical Acid Gas Flare Data
(from NSR Table 8, Flare Systems)

TABLE 8. FLARE SYSTEMS

Number from Flow Diagram	**Manufacturer & Model No. (if available)**
2 (Acid Gas Flare)	**N/A**

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Max.
		(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])
	1. H_2S	0	3.5	4.5
	2.			
	3.			
	4.			
	5.			
	6.			
	7.			
	8.			
% of time this condition occurs				

	Flow Rate (scfm [68°F, 14.7 psia])		Temp. °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	0	4.5	200	10
Fuel Added to Gas Steam	0	7.5	90	10

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [68°F & 14.7 psia]) per pilot
	1	Natural Gas	0.6

For Stream Injection N/A	Stream Pressure (psig)		Total Stream Flow	Temp. °F	Velocity (ft/sec)
	Min. Expected	Design Max.	Rate (lb/hr)		

	Number of Jet Streams	Diameter of Steam Jets (inches)	Design basis for steam injected (lb steam/lb hydrocarbon)

For Water Injection N/A	Water Pressure (psig) Min. Expected Design Max.	Total Water Flow Rate (gpm) Min. Expected Design Max.	No. of Water Jets	Diameter of Water Jets (inches)

Flare Height (ft) 60	Flare tip inside diameter (ft) 0.20

Capital Installed Cost $____________	Annual Operating Cost $________

Supply an assembly drawing, dimensioned and to scale, to show clearly the operation of the flare system. Show interior dimensions and features of the equipment necessary to calculate its performance. Also describe the type of ignition system and its method of operation. Provide an explanation of the control system for steam flow rate and other operating variables.

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Attachment D—NSR Table 4, Combustion Units

OPERATIONAL DATA	
Number from flow diagram:	Model Number(if available):
Name of device:	Manufacturer
CHARACTERISTICS OF INPUT	

Waste Material*	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
	1.			
	2.			
	3.			
	4.			
	5.			

Gross Heating Value of Waste Material (Wet basis if applicable)	Btu/lb ____	Air Supplied for Waste Material	Minimum SCFM (70°F & 14.7 psia) ____	Maximum SCFM(70°F & 14.7 psia) ____

Waste Material of Contaminated Gas	Total Flow Rate lb/hr		Inlet Temperature °F	
	Minimum Expected ____	Design Maximum ____	Minimum Expected ____	Design Maximum ____

Fuel	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
	1.			
	2.			
	3.			
	4.			

Gross Heating Value of Fuel	Btu/lb ____	Air Supplied for Fuel	Minimum SCFM (70°F & 14.7 psia) ____	Maximum SCFM(70°F & 14.7 psia) ____

*Describe how waste material is introduced into combustion unit on an attached sheet. Supply drawings, dimensioned and to scale to show clearly the design and operation of the unit.

FORM PI-2 (72-9)

NSR Table 4, Combustion Units (continued)

CHARACTERISTICS OF OUTPUT

	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
Flue Gas Released	1.			
	2.			
	3.			
	4.			
	5.			

Temperature at Stack Exit °F	Total Flow Rate lb/hr		Velocity at Stack Exit ft/sec	
	Minimum Expected	Maximum Expected	Minimum Expected	Maximum Expected
______	______	______	______	______

COMBUSTION UNIT CHARACTERISTICS

Chamber Volume from Drawing ft^3	Chamber Velocity at Average Chamber Temperature ft/sec	Average Chamber Temperature °F
______	______	______
Average Residence Time sec	Exhaust Stack Height ft	Exhaust Stack Diameter ft
______	______	______

ADDITIONAL INFORMATION FOR CATALYTIC COMBUSTION UNITS

Number and Type of Catalyst Elements	Catalyst Bed Velocity ft/sec	Max. Flow Rate per Catalytic Unit (Manufacturer's Specifications) Specify Units
______	______	______

Attach separate sheets as necessary providing a description of the combustion unit, including details regarding principle of operation and the basis for calculating its efficiency. Supply an assembly drawing, dimensioned and to scale, to show clearly the design and operation of the equipment. If the device has bypasses, safety valves, etc., specify when such bypasses are to be used and under what conditions. Submit explanations on control for temperature, air flow rates, fuel rates, and other operating variables.

10/93

Nichols, Sandra L.

From: Miller, Richard L. (CHO)
Sent: Tuesday, July 22, 2003 10:25 AM
To: Conner, Eugene H.; Glasgow, Randy C.
Cc: Nichols, Sandra L.; Maskell, Robert B.; Zimmermann, Glenn X; McDaniel, William R.
Subject: Meeting for Environmental Procedures

This is what I put together as a reminder.

Gene and Randy will be responsible for:

- Identifying all procedures in the CVON Utilities manuals that are required for an Environmental purpose - regulation, permit or environmental department procedure. These procedures must be noted in the manual as "environmentally critical" and a list must be sent to Glenn Zimmerman
- Contacting Jody Shaw and Paul Dang to find out what needs to be captured about land farm operation in our procedures.
- Creating a procedure that explains sample techniques for various samples caught and that identifies compliance samples
- Documenting the minimum 1000 VSS in a procedure - verify wording in the permit
- Creating a procedure that explains how we must operate to meet LDR requirements in earthen basins
- Ensuring that the procedures describing LOER's and environmentally required paperwork are adequate and accurate.

Rick and Bruce must:

- Work with Mike Piznar to decide what to do with H well

Sandra has already sent a link to the SW846 reg for sampling protocol.

Thank You,

Rick Miller

Environmental Operations Specialist

281-452-8814

The only way to discover the limits of the possible is to venture a little past them into the impossible.