The Dow Chemical Company
2301 N. Brazosport Blvd.
Freeport, Texas 77541
USA

September 12, 2013

Certified Mail 7013 0600 0001 1597 9052 Return Receipt Requested

Jeff Robinson
United States EPA, Region 6
Air Permits Section, 6PD-R
1445 Ross Ave., Suite 1200
Dallas, TX 75202-2733

Re: Updated Light Hydrocarbon 9 GHG Permit Application
Dow Chemical – Texas Operations

Dear Mr. Robinson,

The enclosed electronic media (CD) contains an updated permit application that reflects revisions to the process descriptions and emission calculations for the Light Hydrocarbon 9 GHG permit application. These updates are associated with design changes that have been made since the initial permit application submittal. The updated calculations also include emission estimates for maintenance, startup, and shutdown activities.

Should you have any questions concerning the permit application or the enclosed updated information provided in this response, I can be reached at (979) 238-5832 or via e-mail at clsteves@dow.com.

Respectfully,

Cheryl Steves

Cheryl Steves
Environmental Manager
The Dow Chemical Company

Enclosure/cls

cc: Cindy Rodriguez, Dow Chemical
Mary Schwartz, Dow Chemical

SUMMARY OF PERMIT APPLICATION UPDATES

2.0 Process Description Updates

The furnace decoke emissions have been eliminated from the permit as the decoke drum vents will be routed to the furnace firebox instead of directly to atmosphere. The process description has been updated to reflect this change. The decoke emission points have been removed from the Table 1(a).

Dow has updated the design of the process unit to include a thermal oxidizer for treatment of routine waste gas vents. The process description has been updated to reflect this change, and emissions calculations are attached in Appendix B. This source has been included in the attached Table 1(a).

Dow has updated the representation of routine vents that can be routed to the low pressure flare for control. This flare will serve as a backup control device during periods when the TOX is unavailable. The same vent streams that are represented for the TOX are also being represented for this low pressure flare. Updated flare calculations and the thermal oxidizer calculations are included in Appendix B. Results of an RBLC search for thermal oxidation BACT is included in Appendix D.

The block flow diagram has been updated to remove the decoke drum vents and to add the thermal oxidizer. The plot plan for the unit is currently being updated to incorporate the TOX and will be submitted when finished.

3.0 Emissions Basis Updates

The emission calculations for the backup diesel generators have been updated to reflect revised emission factors based on vendor data for Tier 2 engines. This change does not impact the GHG emissions from the generators, however in order to maintain correct representations of these sources in the permit application, updated emission calculations are included.

This update includes emissions for maintenance, startup, and shutdown activities. These emissions are reflected in the Table 1(a) for the Pressure-Assisted Flare GF-596 (emission point number OC2F5961). Updated flare calculations that include MSS are included in Appendix B.

4.0 Best Available Control Technology Updates

The BACT analysis for the furnaces (Section 4.1) was updated and submitted on February 8, 2013 to reflect a detailed analysis for carbon capture and sequestration. This update has been incorporated into this version of the permit application. None of the technical content of this section was changed - the incorporation is to generate a complete permit application and facilitate an efficient review.

The benchmarking efficiency section of the BACT analysis for the cracking furnaces (Section 4.1.4.2) has been revised to address inconsistencies in the unit of measure for the ratio of GHG emissions per quantity of ethylene produced.

This section was revised to include a BACT analysis for the thermal oxidizer (Section 4.7) and to correct the furnace flue gas temperature on Table 4-11 to reflect the upper limit. The original permit application used the performance limit which does not allow ample margin for furnace operation.

The Dow Chemical Company
Dow Texas Operations – Freeport

Prevention of Significant Deterioration

Greenhouse Gas

Permit Application

for

Ethylene Production Facility (LHC-9)

Revised September 12, 2013

TABLE OF CONTENTS

APPENDICES

LIST OF TABLES

LIST OF FIGURES

SECTION 1.0 INTRODUCTION

The Dow Chemical Company (Dow) owns and operates an existing chemical manufacturing complex near Freeport, Brazoria County, Texas. Dow is submitting this application to authorize the construction and operation of a new ethylene production facility at the Freeport site.

1.1 Project Description

The Dow Chemical Company (Dow) in Freeport, Texas proposes to construct a new ethylene cracker Light Hydrocarbon Plant No. 9 (LHC-9) near Freeport, Texas (Brazoria County). The start of construction is planned for January 2014. The proposed start of operation is January 2017. The LHC-9 Plant will convert cracking feedstocks into ethylene and propylene, C4 compounds, pyrolysis gasoline, fuel oil, and an off-gas stream consisting of primarily hydrogen and methane.

1.2 Non-attainment / PSD Applicability

The proposed project triggers Prevention of Significant Deterioration (PSD) review for several criteria pollutants (nitrogen oxides (NOx), carbon monoxide (CO), particulate matter (PM/PM10/PM2.5), volatile organic compounds (VOC), and sulfur dioxide (SO_2)) for which Texas Commission on Environmental Quality (TCEQ) has an approved permitting program. Dow has submitted a New Source Review and PSD permit application to the TCEQ to authorize the construction of LHC-9 facility and its associated emissions.

On June 3, 2010, the EPA published final rules for permitting sources of Greenhouse Gases (GHGs) under the prevention of significant deterioration (PSD) and Title V air permitting programs, known as the GHG Tailoring Rule. After July 1, 2011, new sources emitting more than 100,000 tons per year (tpy) of carbon dioxide equivalents (CO_2e) and modifications increasing GHG emissions more than 75,000 tpy on a CO_2e basis at existing major sources are subject to GHG PSD review, regardless of whether PSD was triggered for other pollutants.

On December 9, 2010, EPA signed a Federal Implementation Plan (FIP) authorizing EPA to issue PSD permits in Texas for GHG sources until Texas submits the required State Implementation Plan (SIP) revision for GHG permitting and it is approved by EPA.

GHG PSD review is triggered for the LHC 9 project because the project will increase GHG emissions by more than 75,000 tpy on a CO_2e basis. Pursuant to the EPA Tailoring Rule, Dow is submitting this PSD application for the project to EPA to authorize the project's GHG emissions.

This application includes a project scope, process description and block flow diagram, area map, plot plan, GHG emissions calculations, and GHG Best Available Control Technology (BACT) analysis. While there are no significant decreases in GHG emissions at the Dow facility in the contemporaneous period that could potentially result in the project's netting out of GHG PSD review, a detailed GHG contemporaneous netting is included in this application to satisfy the requirement for submittal of netting information.

1.3 TCEQ Forms and Instructions

TCEQ forms for the proposed facility are listed below and can be found in Appendix A.

PI-1	Administrative Information
Table 1F	GHG PSD Applicability Summary*
Table 2	Material Balance

* Since this application covers only GHG emissions and PSD permitting of other pollutants is being reviewed by TCEQ, the PSD applicability form (Table 1F) only includes GHG emissions. As shown on this form, GHG emissions from the project exceed 75,000 tpy of CO_2e, and there are no significant creditable decreases of CO_2e emissions in the contemporaneous period that would change the PSD applicability determination. Therefore, PSD review is required for the project GHG emissions in accordance with the EPA Tailoring Rule.

1.4 Site Description

Dow Texas Operations is located in Brazoria County, which is classified as a severe non-attainment area for ozone. An area map for the proposed LHC-9 facility is provided on the subsequent page. The map includes a 3,000-foot radius circle and a 1-mile radius circle. As indicated on the map, there are no schools located within 3,000 feet of the Dow Freeport facility. A plot plan, which identifies the location of the LHC-9 plant and all the associated equipment sources in relation to roads, highways, and other Dow facilities, is provided on the page following the area map.

Figure 1-1 Area Map

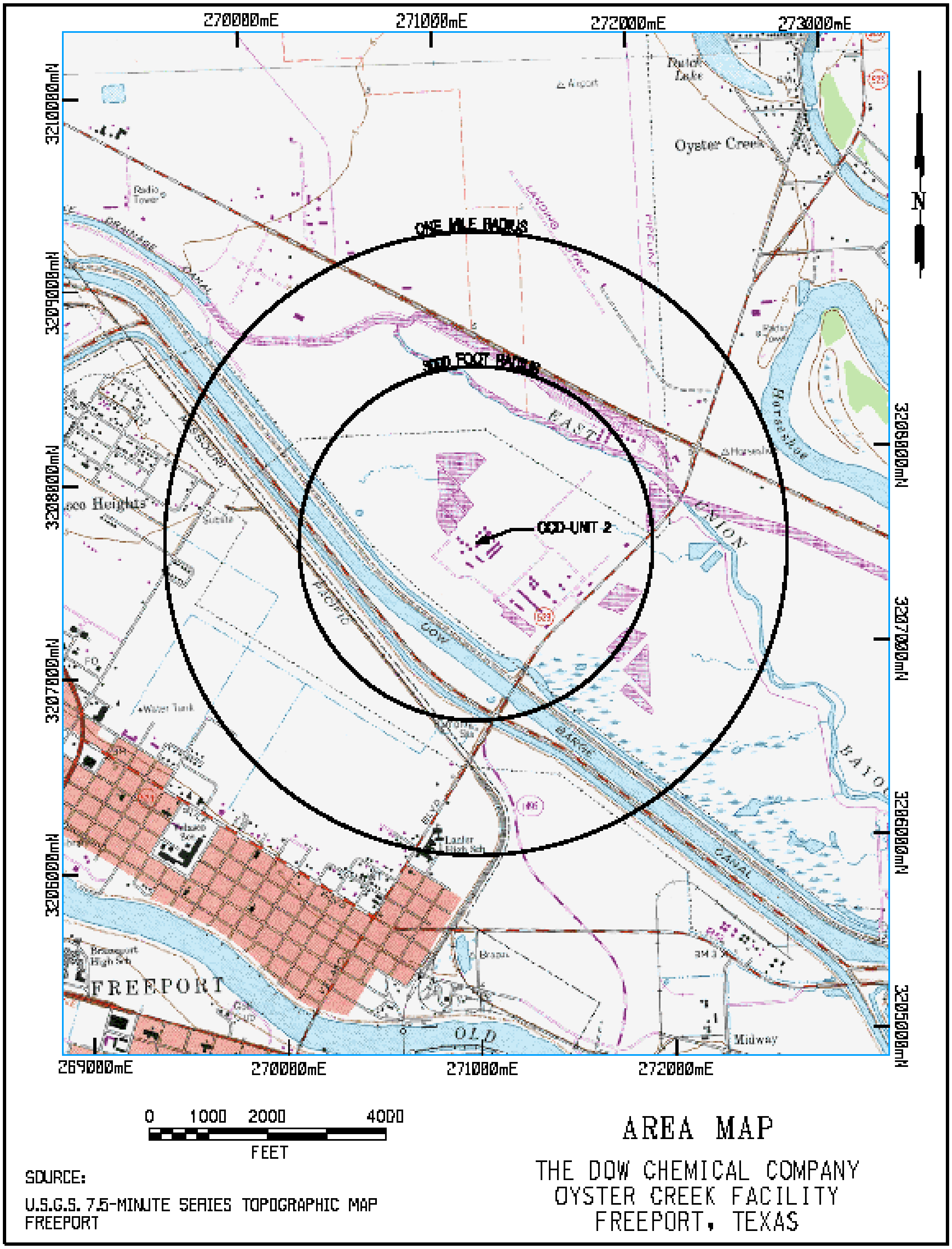


Figure 1-2 Plot Plan

An updated plot plan will be submitted once the revisions for the thermal oxidizer have been completed.

1.5 Upstream / Downstream Analysis

Dow does not anticipate any emission increases from upstream or downstream facilities as a result of the addition of the new LHC-9 facility.

1.5.1 Upstream Impacts

The LHC-9 facility will use ethane and propane as feedstocks. A new pipeline is being installed from Mont Belvieu, Texas to the Dow Freeport complex to provide ethane from a 3rd party to the Dow Freeport site. This pipeline is included in the action area for the cross-cutting regulation assessments required for federal permit issuance. Propane is provided to the site by way of an existing propane pipeline and header system.

The cracking furnaces will be equipped with selective catalytic reduction (SCR) technology to minimize emissions of nitrogen oxides (NOX). Ammonia is the reducing agent that will be used in the SCR system to for chemical reduction of the NOX. The project will require installation of ammonia piping from an existing ammonia header that runs throughout the Dow Freeport site to the LHC-9 furnace SCR devices. This installation will trigger fugitive emissions only, and those emission estimates have been included in the TCEQ New Source Review (NSR) permit.

The crude product from the cracking furnaces will be further processed in a series of quench, distillation, compression, and purification steps. No additional energy is needed to process the cracking feed, except for the steam utilized in downstream processes. The steam produced by the cracking furnaces will be sufficient to cover any increased energy needs.

Process off-gas from LHC-9 operations will be used as fuel in LHC-9 furnaces, distributed within the site low pressure fuel gas (LPFG) system, or used for off-site hydrogen recovery. Electricity and steam will be provided to the proposed facility from existing production units, 3rd party facilities, and existing tie-lines.

1.5.2 Downstream Impacts

The primary products produced at the LHC-9 facility (ethylene and propylene) will be used as feed stock for other existing units at the Dow Freeport site or transported via pipeline to existing underground storage caverns and exported off-site to other consumers.

By-product streams as well as off-gas from the LHC-9 unit may be routed to existing facilities at the site for product recovery and energy recovery. The Dow Freeport site is a highly integrated chemical manufacturing complex. This integration allows product and by-product streams to be processed by downstream plants resulting in efficient and low-cost production capability.

Wastewater generated by the unit will be routed to an existing on-site wastewater treatment facility. The wastewater discharged from the site wastewater treatment plant will not vary from other discharges already managed by this facility; therefore, no new pollutants will be treated or discharged.

SECTION 2.0 PROCESS DESCRIPTION

The proposed project includes construction of a new ethylene unit (LHC-9) and associated utilities. The new unit will include eight (8) new steam cracking furnaces, recovery equipment, utility, refrigeration, cooling, and treatment systems. The major pieces of recovery equipment include a quench tower, cracked gas compression, caustic wash tower, chilling train, refrigeration systems, deethanizer, ethylene/ethane (C2) splitter, demethanizer, depropanizer, and debutanizer. In addition, a new cooling tower and new flare system will be constructed.

The new plant will process hydrocarbon feedstocks to produce ethylene and other products. A process flow sequence is shown on the block flow diagram, Figure 2-1. Design capacity is included in Appendix A on the Table 2 Material Balance. The operating schedule for this facility is 8760 hours per year.

2.1 Cracking Furnaces

2.1.1 Feed Preparation

Fresh ethane feed to the plant is filtered, dried, mixed with recycle ethane from the C2 splitter, and fed to the furnaces. Crude ethane feed to the plant is mixed with the fresh and recycled ethane feeds and fed to the furnaces.

Fresh propane feed to the plant is filtered and fed to the furnaces. Mixed C3s from the Depropanizer and mixed C4s from the Debutanizer section can be recycled to the feed to the furnaces.

2.1.2 Cracking Furnaces

The cracking section consists of 8 furnaces of proprietary design (EPNs: OC2H121 through OC2H128). These furnaces receive hydrocarbon feeds from the Feed Preparation Section and react them by pyrolysis in the presence of steam to produce a mixed gas stream of products, byproducts, un-reacted feedstocks, and steam. This cracked gas stream is fed to the Quench System. The furnaces also generate high pressure steam, which is fed to the plant steam system.

The furnaces are fired on fuel from the plant fuel gas supply system. Combustion of fuel gas generates the heat required for completing the pyrolysis reaction in the furnace tubes. Emissions such as NOx, CO_2, CO, and particulate matter (PM) are generated during combustion, and are vented to atmosphere through the furnace stacks. The furnaces are equipped with burners designed to operate with low NOx, CO, and PM emissions. Selective catalytic reduction (SCR) systems are also included on the furnaces to further control NOx emissions.

2.1.2.1 Furnace Fuels

The furnaces are capable of firing on a variety of fuels. Fuel selection is based on availability and market factors. Typical fuels and their associated terminology for the cracking furnaces are:

Natural Gas	Primarily methane; natural gas is supplied to the Dow Freeport site from 3rd party suppliers and arrives by way of existing pipeline systems. This fuel is available for use at the LHC-9 from the existing utility system. The calculations include emissions for firing on Natural Gas as one of the fuel cases.

Off Gas	Primarily a hydrogen/methane stream produced in the LHC-9 process. This stream can be recycled for use in dryer regeneration, used as fuel in the furnaces, or exported to a 3rd party for hydrogen recovery. The calculations include emissions for firing on Off Gas as one of the fuel cases
Resid Gas	Residual Gas; a primarily methane/hydrogen stream (less hydrogen though than Off Gas) that is returned from a 3rd party hydrogen recovery facility.
Fuel Gas	This term is a general one and refers to whatever fuel is being sent to the furnaces. It could be Off Gas, Natural Gas, or a combination of either of those with Resid Gas. It's used when the intent is to be non-specific to the composition of the stream being sent to the furnaces for fuel.
Regen Gas	Regeneration Gas; this is the Off Gas or Resid Gas streams when being used for the purpose of regenerating LHC-9's dehydrators.

2.1.2.2 Decoking

During the cracking reaction, coke is formed in the furnace tubes that must be periodically removed by steam/air decoking. In this decoking process the coke is removed by oxidation and spalling. The spalled coke is removed from the decoke effluent in the decoke drum; the decoke drum vent is routed to the furnace firebox eliminative the decoke vent. The furnace operates for approximately fifty (50) days between decokes.

2.2 Product Recovery

2.2.1 Quench System

In the Quench system, the cracked gas product from the furnaces is cooled in a quench tower where the majority of the dilution steam and some of the heavier hydrocarbons are condensed. Cracked gas from other existing facilities at the site may also be fed to the Quench System for the purpose of reducing the need to flare these streams. This is typical during maintenance of the other existing facility. Condensed water and hydrocarbons from the bottom of the tower flow to the Dilution Steam Generation/Quench Water Clean-up Section for further processing. Cooled cracked gas is sent to the Cracked Gas Compression System.

2.2.2 Dilution Steam Generation/Quench Water Clean-up

In the Quench Water Clean-up system, the water and oil from the quench tower is fed to a quench water separator where oil and water separation occurs. The water from the quench water separator is treated further to remove residual oil and is stripped with steam to remove soluble hydrocarbons. This stripped quench water is pumped to the dilution steam generator for the purpose of generating steam for use in the cracking furnaces.

The oil stream from the quench water separator is processed further in the debutanizer to remove contaminants and exits the plant as a pyrolysis gasoline (Pygas) product stream. The Pygas stream is routed to an existing storage tank and combined with a Pygas stream from another existing production unit.

2.2.3 Cracked Gas Compression

Cracked gas from the quench tower overheads is compressed in three stages in the cracked gas compressor. After the final inter-stage cooling, the compressed cracked gas is forwarded to the Caustic Wash system. The compressor will be driven by steam turbine.

2.2.4 Caustic Wash

The caustic wash tower removes CO_2 and sulfur compounds from the cracked gas. The CO_2 and sulfur compounds are removed by reaction with caustic (NaOH), forming soluble compounds. Cracked gas leaving the caustic wash tower is cooled, and condensed liquid is separated before the cooled gas is forwarded to the Drying section. Condensed hydrocarbons are continuously removed from the bottom of the tower, along with spent caustic. Spent caustic is processed to remove hydrocarbons and sent forward to the Spent Caustic Treatment.

2.2.5 Dryers

Drying of the cracked gas is necessary to prevent hydrate formation in the colder downstream process operations. Desiccant is used in the dryers to remove moisture. When the desiccant in a dryer becomes saturated with water, it will be regenerated and the standby dryer placed in service. Dried cracked gas is fed to the Deethanizer.

2.2.6 Deethanizer

The Deethanizer separates the cracked gas into an overheads stream of ethane and lighter components, and a bottoms stream of C3 and heavier components. The overheads stream of ethane and lighter components is compressed and fed to the Acetylene Reaction System. The bottoms stream of C3 and heavier components is fed to the Depropanizer for further separation. The Deethanizer overheads compressor will be driven by steam turbine.

2.2.7 Acetylene Reactors

The Acetylene reactors remove acetylene (an undesirable by-product) from the Deethanizer overheads stream through selective hydrogenation to ethylene and ethane. After hydrogenation, the reactor effluent is dried and partially condensed. Liquid and vapor are then separated, with liquid returned to the Deethanizer as reflux and vapor fed to the Demethanizer Section for further separation.

2.2.8 Demethanizer

The Demethanizer Section separates the vapor from the Acetylene Reactor System into a vapor stream of methane and lighter components, and a bottoms stream of ethane and ethylene. First, the stream from the Acetylene Reactor System is partially condensed and vapor/liquid separated in demethanizer feed chillers and knockout drums. The remaining vapor is fed to the Cold box/Expanders Section for further processing. The condensed liquid is fed to the Demethanizer column for further separation.

The Demethanizer column separates the condensed liquid stream into an overheads stream of methane and lighter components, and a bottoms stream of ethane and ethylene. The overheads stream of methane and lighter components is recycled to the Deethanizer. The bottoms stream of ethane and ethylene is fed to the C2 Splitter for further separation.

2.2.9 Cold box/Expander

The Cold box/Expander Section further processes the vapor stream from the Demethanizer Section to recover ethylene and refrigeration value. The vapor stream from the Demethanizer feed knockout drum is cooled and expanded to recover ethylene. The remaining vapor stream (Off Gas) from the expanders is primarily methane and hydrogen, and is recycled to the Fuel Gas/Dryer Regen System.

2.2.10 C2 Splitter

The C2 splitter separates the Demethanizer bottoms stream into an overheads stream of ethylene, and a bottoms stream of ethane. The overheads stream of ethylene is compressed, condensed, pumped, and leaves the plant as the main product stream. The bottoms stream of ethane is recycled to the Feed Preparation Section. A crude ethylene stream from existing facilities may also be fed to the C2 splitter for separation.

2.2.11 Depropanizer

The Depropanizer separates the Deethanizer bottoms stream into an overheads stream of propane and propylene, and a bottoms stream of C4 and heavier components. The overheads stream of propane and propylene leaves the plant as a mixed C3 product stream, and can be used as makeup to the propylene refrigeration system or recycled to the Feed Preparation Section. The bottoms stream of C4 and heavier components is fed to the Debutanizer for further separation.

2.2.12 Debutanizer

The Debutanizer separates the Depropanizer bottoms stream into an overheads stream of C4 components, and a bottoms stream of C5 and heavier components. The overheads stream of C4s leaves the plant as a mixed C4 product stream, and can be recycled to the Feed Preparation Section. The bottoms stream of C5 and heavier components is combined with oil from the Quench Section and leaves the plant as a Pygas product stream. A crude C4+ stream from existing facilities may also be fed to the Debutanizer for separation.

2.2.13 Fuel Gas/Dryer Regen

The Off Gas from the Cold box/Expander Section is recycled to the Fuel Gas/Dryer Regen system for use in Dryer Regeneration, as fuel in the Cracking Furnaces, or exported as an Off Gas product. The Fuel Gas/Dryer Regen System can be supplemented with Fuel Gas/Regen Gas import, which can include natural gas and other similar hydrogen and methane containing gas streams from other facilities.

Dryers that have been saturated with moisture are regenerated with heated Off Gas, which is recovered in the plant Fuel Gas/Dryer Regen System.

2.3 Refrigeration

2.3.1 C2 Refrigeration

An ethylene refrigeration system will be constructed for providing refrigerant to the proposed plant. The compressor will be driven by steam turbine.

2.3.2 C3 Refrigeration

A propylene refrigeration system will be constructed for providing refrigerant to the proposed plant. The compressor will be driven by steam turbine.

2.4 Cooling Tower

A cooling tower (EPN: OC2CT936) will be constructed to provide process heat removal. This cooling tower will be a multi-cell, induced draft, counter-flow type cooling tower.

Wet cooling towers provide direct contact between the cooling water and air passing through the tower, and as part of normal operation, a very small amount of the circulating water may be entrained in the air stream and be carried out of the tower as “drift” droplets. Because the drift droplets may contain the same salt impurities as the water circulating through the tower, the particulate matter constituent of the drift droplets is classified as an emission. Cooling water conductivity and total dissolved solids are parameters used estimate particulate emissions from the unit.

VOC emissions from the cooling tower are generated by leakage of hydrocarbons from process heat exchangers into the cooling water system, and are released to atmosphere with the cooling tower fan discharge to atmosphere. The cooling water system will include totalizing flow measurement and on-line analysis to detect and speciate HRVOC (Highly Reactive Volatile Organic Compounds) hydrocarbons in the cooling water.

2.5 Flare System

A new flare system and thermal oxidizer (EPNs: OC2F5961, OC2F597, and OC2TOX) will be constructed to provide safe control of gases vented from the proposed plant. This system will consist of a pressure-assisted flare for managing the main portion of vented gases, a thermal oxidizer for managing lower pressure vent streams including those from the plant’s storage tanks, and a low pressure flare. The low pressure flare will serve as backup control for the thermal oxidizer during periods when the unit is down for maintenance. The flares will be equipped with totalizing flow measurement and on-line analysis to speciate the hydrocarbons in the flared gases, including HRVOCs.

2.6 Rainwater/Wastewater

The proposed plant will include systems to collect rain water and process wastewater.

Rainwater and other pad water such as fire fighting water is collected in sumps located throughout the process area. The contained water is tested for contamination. Clean water is recycled to the cooling water system. Contaminated water is filtered, stripped, and exported to an on-site treatment facility.

A small continuous stream of process wastewater is generated from concentrated blow down of the Dilution Steam Generator, which is necessary for maintenance of water quality. Additional process wastewater is produced during periods of reduced process steam generation, such as during maintenance or cleaning of process steam generation equipment. Process wastewater is collected in a tank and pumped to an on-site waste water treatment facility.

2.7 Spent Caustic Pretreatment

Spent caustic from the Caustic Wash system is filtered and stripped to remove contaminants prior to being pumped to an existing on-site wet air oxidation (WAO) system. In the wet air oxidation system the spent caustic is further treated to convert sulfides to sulfates, and is then routed to an on-site waste water treatment facility. The WAO system vents are routed to the thermal oxidizer.

2.8 Steam/Condensate/Boiler Feed Water

The proposed project will include a steam system, condensate system, and boiler feed water system. Polished water from the Condensate Collection/Polishing system is de-aerated and pumped to furnaces for high pressure steam generation. High pressure steam generated in the furnaces is used as driver for the plant steam turbines, and is condensed or exported to the Site.

2.9 Condensate Collection/Polishing System

The proposed plant will include a system for collecting steam condensate and polishing to cleanliness specification required for use in high pressure steam generation. Collected steam condensate is polished using ion exchange. The polishing beds become exhausted after removing their maximum capacity of hardness from the water stream, and require regeneration with Hydrochloric Acid (HCl). The Polishing system includes a polisher neutralizer tank (EPN: OCST924) for collection of liquid generated during the regeneration process. This tank vents to atmosphere through a scrubber which controls HCl vapor emissions.

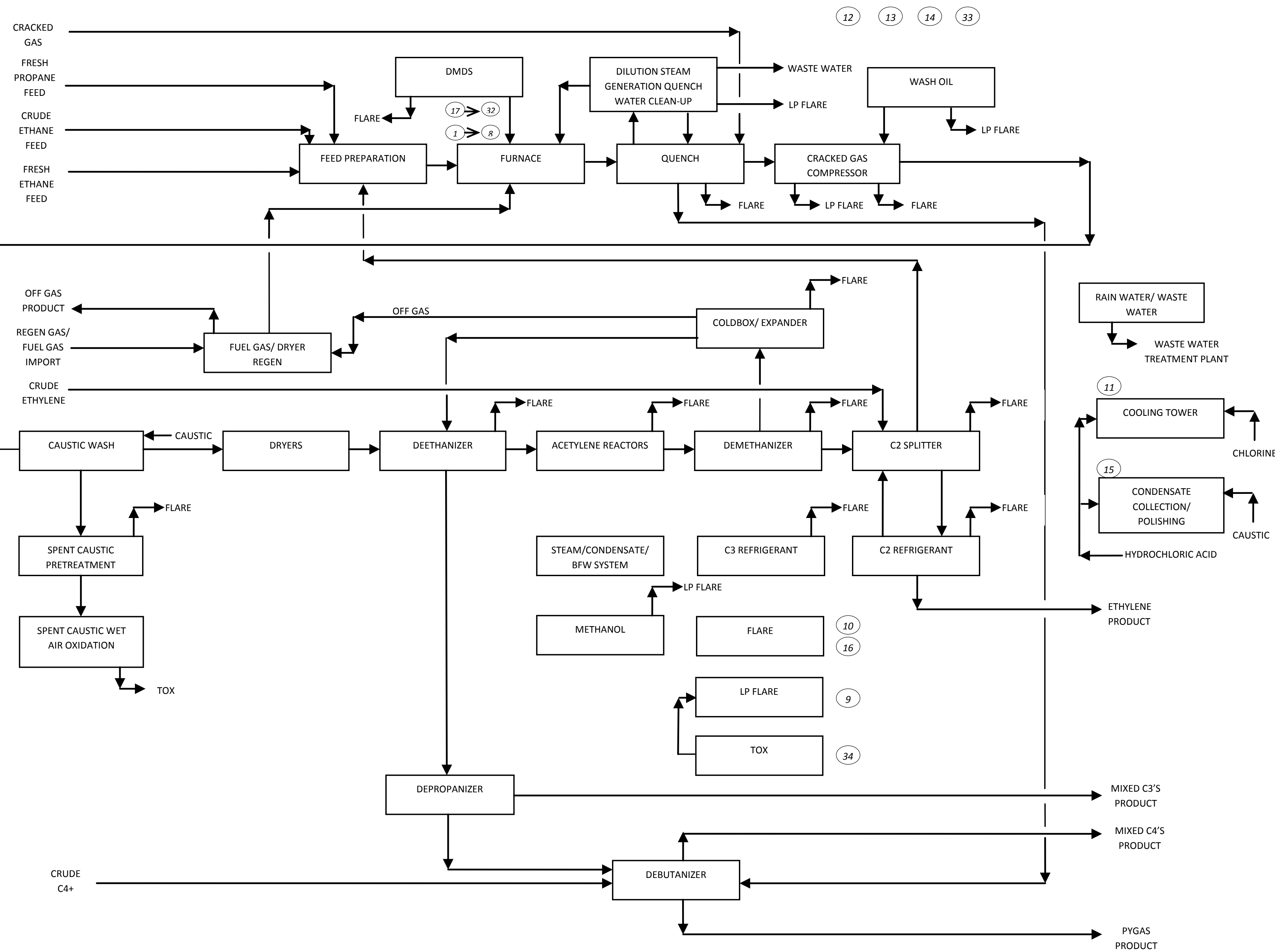
2.10 Storage Tanks

Several new storage tanks are included in the proposed plant. These tanks will store materials such as ammonia, compressor wash oil, lube oil, caustic, spent caustic, sulfuric acid, methanol, and various water and process additives. Some tanks will be routed to control (thermal oxidizer). No increase in GHG emissions are being represented from the proposed storage tanks with atmospheric vents.

2.11 Engines

The plant includes two backup generators sized for selected critical plant electrical loads. Backup power for these critical loads is required to prevent damage to major plant equipment during power interruption. Each generator is powered by a diesel engine (EPNs: OC2GE1 and OC2GE2) and there is one diesel tank associated with each backup generator. These generators are normally not operating, and are only used during power interruptions and during routine readiness testing. Routine testing of the generators is a weekly start and partial load test to ensure readiness for service during interruption of normal power supply.

Figure 2-1 Block Flow Diagram



INDEX NO.	EPN	FIN	NAME
1	OC2H121	OC2L9H121	CRACKING FURNACE F-121
2	OC2H122	OC2L9H122	CRACKING FURNACE F-122
3	OC2H123	OC2L9H123	CRACKING FURNACE F-123
4	OC2H124	OC2L9H124	CRACKING FURNACE F-124
5	OC2H125	OC2L9H125	CRACKING FURNACE F-125
6	OC2H126	OC2L9H126	CRACKING FURNACE F-126
7	OC2H127	OC2L9H127	CRACKING FURNACE F-127
8	OC2H128	OC2L9H128	CRACKING FURNACE F-128
9	OC2F597	OC2L9F597	LP FLARE FS-597
10	OC2F5961	OC2L9F596	MAIN GROUND FLARE GF-596
11	OC2CT936	OC2L9CT936	COOLING TOWER CT-936
12	OC2FU2	OC2L9FU2	PROCESS AREA FUGITIVES
13	OC2GE1	OC2L9GE1	BACKUP DIESEL GENERATOR NO. 1
14	OC2GE2	OC2L9GE2	BACKUP DIESEL GENERATOR NO. 2
15	OC2ST924	OC2L9ST924	POLISHER NEUTRALIZER TANK V-924
16	OC2F5962	OCL9MEPU	PROCESS UNIT MAINT/STARTUP/ SHUTDOWN
17	OC2MEP121	OC2L9MEP121	GUEL GAS PURGE VENT F-121
18	OC2MEP122	OC2L9MEP122	GUEL GAS PURGE VENT F-122
19	OC2MEP123	OC2L9MEP123	GUEL GAS PURGE VENT F-123
20	OC2MEP124	OC2L9MEP124	GUEL GAS PURGE VENT F-124
21	OC2MEP125	OC2L9MEP125	GUEL GAS PURGE VENT F-125
22	OC2MEP126	OC2L9MEP126	GUEL GAS PURGE VENT F-126
23	OC2MEP127	OC2L9MEP127	GUEL GAS PURGE VENT F-127
24	OC2MEP128	OC2L9MEP128	GUEL GAS PURGE VENT F-128
25	OC2MEC121	OC2L9MEC121	REFRACTORY CURING F-121
26	OC2MEC122	OC2L9MEC122	REFRACTORY CURING F-122
27	OC2MEC123	OC2L9MEC123	REFRACTORY CURING F-123
28	OC2MEC124	OC2L9MEC124	REFRACTORY CURING F-124
29	OC2MEC125	OC2L9MEC125	REFRACTORY CURING F-125
30	OC2MEC126	OC2L9MEC126	REFRACTORY CURING F-126
31	OC2MEC127	OC2L9MEC127	REFRACTORY CURING F-127
32	OC2MEC128	OC2L9MEC128	REFRACTORY CURING F-128
33	OC2MEFU2	OC2L9MEFU2	LHC9 FUGITIVE MSS
34	OC2TOX	OC2L9TOX	LHC-9 TOX

SECTION 3.0 EMISSIONS BASIS

Detailed GHG emission calculations for the proposed LHC-9 facility are provided in Appendix B of this application. The GHG emissions from the proposed LHC-9 facility will include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). GHG emissions are calculated from the following sources for the proposed project:

- Cracking furnaces
- Flare system
- Routine emergency generator testing
- Fugitive emissions from piping components in GHG service

The CO_2e emissions are calculated based on the estimated annual mass rates for each applicable GHG multiplied by the global warming potential (GWP) for each specific GHG as provided in Table A-1 of Subpart A of 40 CFR part 98.

Table 3-1, at the end of this section, provides proposed emission rates for individual GHGs and corresponding CO_2e.

3.1 Cracking Furnaces

The LHC-9 facility will include eight steam cracking furnaces. Calculations of GHG emissions from these furnaces and GHG emissions from decoking operations are provided in Appendix B.

3.1.1 Normal Firing

The cracking furnaces will typically combust plant off gas; however, the furnaces may also operate on pipeline quality natural gas. The proposed allowable GHG emissions are based on the maximum emissions from either scenario, which is the combustion of natural gas. The plant must maintain flexibility to fuel the furnaces using either the hydrogen-rich off-gas stream or to use natural gas. Market conditions such for natural gas and hydrogen will influence which fuel is used, therefore substitution of hydrogen for natural gas as an enforceable permit condition is not a viable option. A requirement to use hydrogen fuel in place of natural gas when available and not sold as product is considered to be an acceptable option.

Annual emissions estimates for routine operations assume continuous operation at the expected annual average firing rate. GHG emissions from the furnaces were estimated using EPA's GHG reporting methodology as detailed in 40 CFR Part 98, Subpart X, §98.243(d) for ethylene production processes.

3.1.2 Decoking Operation

CO_2 emissions are produced in the decoking process from the combustion of the carbon buildup on the furnace tubes. The furnaces are fired during decoking operations a lower rate than the basis used for annual fuel firing for each furnace. Therefore, fuel firing during decoking operations is already accounted for in the 8,760 hours/year/furnace normal firing scenarios discussed in Section 5.1.1 above.

3.2 Flare System/Thermal Oxidizer

The flare system consists of a small elevated flare (LP Flare) and a pressure-assisted flare as well as a thermal oxidizer. The thermal oxidizer (TOX) is designed to control fugitive emissions from compressor seals, vents from the wet air oxidation unit (WAO), low pressure process vent streams, and storage tank vents. The small elevated flare will serve as backup control for these vent streams when the TOX is unavailable. There is a continuous nitrogen (N_2) and natural gas purge to maintain header velocity and heating value of the flared stream.

Normal flaring operations include controlling vents that can be classified into three main types of activities: fugitive-like sources such as safety relief and pressure control valves that are closed during routine operation, maintenance activities, and process adjustments to maintain product quality. These activities are expected to use the low pressure burners of the pressure-assisted flare. The flow rates used in the emission calculations are based on measured values of a similar plant with adjustments for capacity and complexity.

For each stream, the total mass of vapors and the weight percent of each component were used to estimate stream properties and corresponding GHG emissions. The stream characteristics used for the GHG emissions basis are provided in Appendix B. Although these stream details are provided for emissions estimation purposes, speciation and total flow rates are based on process design as well as similar operating facilities' typical streams. Speciation and or flow volume may vary depending on process conditions and additional compounds similar to those represented may be present.

GHG emissions estimates are based on natural gas firing for the flare pilots and TOX burners, and process vent combustion for the balance of the flared stream. The flare/TOX GHG emissions are calculated based on 40 CFR Part 98, Subpart X, §98.243(d) emissions estimation methodology.

3.3 Piping Fugitives

The facility will have fugitive emissions from piping components in fuel gas and natural gas service. Fuel gas and natural gas both contain primarily methane, with additional heating value derived mostly from hydrogen (fuel gas) and ethane (natural gas). Other process streams at the LHC-9 facility in volatile organic compound (VOC) service will contain only insignificant quantities of GHGs as compared to other GHG sources at the facility and therefore, are not considered further in this application.

As there are no established GHG piping fugitive emission factors, Dow applied the average Synthetic Organic Chemical Manufacturing Industry (SOCMI) average emissions factors for petrochemical processes to the estimated fuel gas components to estimate fugitive total mass emissions. For the natural gas piping components, Oil and Gas emission factors were used to estimate fugitive total mass emissions. Because many of these components may be in either natural gas or fuel gas service, and because natural gas is over 90% methane (a GHG), Dow conservatively assumed 100% of the mass emissions to be methane.

3.4 Emergency Generators

Two diesel-fired emergency generators will only operate during emergencies and on regularly scheduled intervals for readiness testing. It is estimated that the generator will be operated a maximum of 100 hours per year for testing. There will be no other emissions from the generator during normal operation.

GHG emissions from the diesel-fired engines follow the approach for general combustion devices represented in 40 CFR Part 98, Subpart C and the emission factors for No. 2 distillate fuel represented in Tables C-1 and C-2 of Part 98.

3.5 Maintenance, Startup, and Shutdown [MSS]

Normal plant startup requires flaring of cracked gas product while the furnaces and cracked gas compressors are brought on-line. Additional flaring of product is required while distillation and separation are established. Routine maintenance activities associated with cleaning/clearing process equipment are expected.

One type of planned shutdown is a large-scale plant turnaround that occurs at a frequency of once every two to five years. A planned shutdown involves maintenance activities, process clearing, and cleaning to improve plant reliability. During these large scale shutdowns, the plant is totally cleared of all hydrocarbons via flaring. Emissions from this event are less than the emissions from the planned startup. Another type of planned shutdown activity involves portions of the unit operation, not the entire plant. On occasion, it is necessary to shutdown a section of the plant for planned maintenance work that must occur in between the large-scale shutdown events. Additionally, individual pieces of equipment may be shutdown and cleared to address mechanical or operational issues.

Estimated emissions from the flare due to scheduled maintenance, start-up, and shutdown (MSS) activities are broken down by activity type. Maintenance flaring includes control of streams generated from clearing equipment in preparation for maintenance. Start-up flaring includes control of streams generated from startup activities in different sections of the facility. Shutdown stream flaring is assumed to be approximately one half of each of the start-up streams.

For each flared stream, the total mass of vapors and the weight percent of each component were used to estimate stream properties and corresponding GHG emissions. The stream characteristics used for the flare GHG emissions basis are provided in Appendix B. Although these stream details are provided for emissions estimation purposes, speciation and total flow rates are based on process design as well as similar operating facilities' typical streams. Speciation and or flow volume may vary depending on process conditions and additional compounds similar to those represented may be present.

GHG emissions estimates are based on natural gas firing for the pilots and process vent combustion for the balance of the flared stream. The GHG emissions are calculated based on 40 CFR Part 98, Subpart X, §98.243(d) emissions estimation methodology.

Table 3-1 Proposed GHG Emission Limits

Date:	September 12, 2013	Permit No.:	TBD	RN Number:	100225945
Area Name:	LHC-9 Unit			CN Number:	600356976

AIR CONTAMINANT DATA				
1. EMISSION POINT			2. COMPONENT NAME	3. AIR CONTAMINANT EMISSION RATE
EPN	FIN	NAME		TPY
(A)	(B)	(C)		
OC2H121	OC2L9H121	Cracking Furnace, F-121	CO2	278,357
			CH4	5.19
			N2O	0.52
			CO2e	278,627
OC2H122	OC2L9H122	Cracking Furnace, F-122	CO2	278,357
			CH4	5.19
			N2O	0.52
			CO2e	278,627
OC2H123	OC2L9H123	Cracking Furnace, F-123	CO2	278,357
			CH4	5.19
			N2O	0.52
			CO2e	278,627
OC2H124	OC2L9H124	Cracking Furnace, F-124	CO2	278,357
			CH4	5.19
			N2O	0.52
			CO2e	278,627
OC2H125	OC2L9H125	Cracking Furnace, F-125	CO2	278,357
			CH4	5.19
			N2O	0.52
			CO2e	278,627
OC2H126	OC2L9H126	Cracking Furnace, F-126	CO2	301,855
			CH4	5.63
			N2O	0.56
			CO2e	302,148
OC2H127	OC2L9H127	Cracking Furnace, F-127	CO2	301,855
			CH4	5.63
			N2O	0.56
			CO2e	302,148
OC2H128	OC2L9H128	Cracking Furnace, F-128	CO2	301,855
			CH4	5.63
			N2O	0.56
			CO2e	302,148
OC2F597	OC2L9F597	Low Pressure Flare, FS-597	CO2	14,034
			CH4	0.22
			N2O	0.02
			CO2e	14,046
OC2F5961	OC2L9F596	Pressure-Assisted Flare, GF-596	CO2	43,910
			CH4	2.13
			N2O	0.42
			CO2e	44,085
OC2FU2	OC2L9FU2	Process Area Fugitives	CO2	0.02
			CH4	3.82
			CO2e	80.31
OC2GE1	OC2L9GE1	Backup Diesel Generator No. 1	CO2	16.04
			CH4	0.001
			N2O	0.0001
			CO2e	16.10
OC2GE2	OC2L9GE2	Backup Diesel Generator No. 2	CO2	16.04
			CH4	0.001
			N2O	0.0001
			CO2e	16.10
OC2TOX	OC2L9TOX	LHC-9 TOX	CO2	3,318.92
			CH4	0.06
			N2O	0.007
			CO2e	3,322.45

Total GHG Emissions

Component	TPY
CO2	2,358,646
CH4	49.07
N2O	4.73
CO2e	2,361,144

SECTION 4.0 BEST AVAILABLE CONTROL TECHNOLOGY

In the EPA guidance document titled *PSD AND TITLE V PERMITTING GUIDANCE FOR GREENHOUSE GASES – MARCH 2011*, EPA recommended the use of the Agency's five-step "top-down" BACT process to determine BACT for GHGs[1]. In brief, the top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT.

EPA has broken down this analytical process into the following five steps:

Step 1: Identify all available control technologies

Step 2: Eliminate technically infeasible options

Step 3: Rank remaining control technologies

Step 4: Evaluate most effective controls and document results

Step 5: Select the BACT

The project contains the following sources of GHG emissions:

- Cracking Furnaces
- Decoking Activities
- Flare System
- Emergency Generators
- Piping Fugitives

CO_2 emissions account for approximately 99 percent of the total CO_2e emissions for the proposed project. CH_4 and N_2O contribute insignificantly to the overall GHG emissions potential. Therefore, the GHG BACT analysis is focused on CO_2.

Dow searched the EPA RACT/BACT/LAER Clearinghouse (RBLC) database only for applicable CO_2 BACT determinations to assist in identifying potential GHG control technologies relevant to the proposed emissions sources. The results of a RBLC Database search are included in Appendix D to this application.

The EPA recognizes that currently there are essentially only two methods for potentially reducing and controlling GHG emissions. These controls are improved energy efficiency and carbon capture and sequestration, and are included in this BACT analysis.

[1] Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, United States Environmental Protection Agency, pg 18, March 2011.

4.1 BACT for Cracking Furnaces and Recovery Section

The overall energy efficiency of an ethylene plant is primarily determined by two factors: 1) the thermal efficiency of the cracking furnaces and 2) the efficiency of the recovery section of the plant in separating the cracked gas into final products. Each section of the plant consumes about 50% of the total energy associated with ethylene production. While the furnaces are the primary CO_2 emission source in the plant, the total energy consumption of an ethylene plant is distributed evenly across the furnaces and the recovery section. To analyze the efficiency of a new ethylene plant, it is necessary to evaluate both the Furnace and Recovery section efficiency and because of the steam and energy integration, the plant as a whole.

The majority of GHG emissions associated with the LHC-9 production unit are from the cracking furnaces. Stationary combustion sources primarily emit CO_2, but they also emit a small amount of N_2O and CH_4. The new furnaces being installed for this project will be equipped with the latest technology for optimum thermal efficiency. The proposed cracking furnaces will be fueled by natural gas and plant off gas. The combined fuel gas composition will contain hydrogen (typically 30 to 80% by volume), methane and 1-2 wt% other chemicals (including ethane and propane). The furnaces will be equipped with a selective catalytic reduction system (SCR) to reduce NO_X emissions.

4.1.1 Step 1: Identify Available Control Technologies

The best way to minimize combustion related GHG emissions is through thermal efficiency which is achieved through design and operations. Good combustion practices are considered BACT. The following technologies were identified as potential control options for the furnaces based on review of available information and data sources:

1. Energy and Thermal Efficient Design
    - Efficient Furnace and Recovery Section Design
    - Oxygen Trim Control and Good Combustion Practices
    - Periodic Tune Ups and Maintenance
2. Use of Low-Carbon Gaseous Fuels
3. Carbon Capture and Storage (CCS) as an add-on control

4.1.2 Step 2: Eliminate Technically Infeasible Options

The technologies identified in Step 1 are all technically feasible.

4.1.3 Step 3: Rank Remaining Control Technologies

Because thermal efficiencies include work practice standards, it is difficult to discriminate control efficiencies for ranking. For this reason, the technologies listed in Step 1 have not been ranked here, and are addressed in detail in Step 4.

4.1.4 Step 4: Evaluate the Most Effective Controls

4.1.4.1 Energy and Thermal Efficiency

Overall CO_2 emissions directly related to the LHC-9 plant operations are inversely proportional to the overall plant efficiency. As plant efficiency improves, less energy is consumed and subsequently less CO_2 is emitted for the same amount of production.

The overall energy efficiency of an ethylene plant is primarily determined by two factors: 1) the thermal efficiency of the cracking furnaces and 2) the efficiency of the recovery section of the plant in separating the cracked gas into final products. Each section of the plant consumes about 50% of the total energy associated with ethylene production. While the furnaces are the primary CO_2 emission source in the plant, the energy consumption of an ethylene plant is in fact distributed evenly across the furnaces and the recovery section. To analyze the efficiency of a new ethylene plant, it is necessary to evaluate both the furnace and recovery section efficiency and because of the steam and energy integration, the plant as a whole.

Dow will implement an energy efficient technology for both the furnaces and the recovery section that will result in fewer overall emissions for all air pollutants per unit of production. The paragraphs below summarize the most significant factors that influence the efficiency of the plant and the benchmarking data will demonstrate that the chosen design will be an industry leader in energy efficiency.

Efficient Recovery Section Design and Operation - The main factor determining the energy efficiency of the recovery section of an ethylene plant is the effectiveness of the selected flowsheet design to efficiently separate the crack gas from the furnaces into the final products. Factors influencing the flowsheet efficiency include:

- Heat and refrigeration recovery and integration
- Sequence of product separation and distillation
- Efficiency of selected unit operations such as steam turbines and distillation columns
- Minimizing recycles and losses.

Dow's evaluation and selection of the available ethylene technologies took into careful consideration all attributes of the technology including ethylene yield, reliability, and energy efficiency. Since the overall efficiency of an ethylene unit is highly dependent on both the furnaces and the recovery section efficiency and considering the complexity of analyzing different technical options for use of fuel, steam, and electricity as energy inputs, the best measurement for analyzing the efficiency of the entire plant is overall plant energy consumption per unit of production. As the benchmarking data demonstrates, Dow's selected technology will be an industry leader in efficiency.

Operation and Maintenance – The efficiency of the LHC-9 recovery section will need to be monitored and maintained in order to retain the full benefit of the selected design. This will include the following steps:

- Continuous process monitoring, automated process control, and advanced control techniques
- Routine process cleaning and maintenance as required
- Maintaining design operating rates.

Where fouling potential exists, the Dow design will incorporate either spare equipment or on-line cleaning methods where practical to maintain efficient operation between major maintenance intervals.

Efficient Furnace Design and Operation - As described in the previous section, the cracking furnaces are the single largest fuel consumer and account for more the 50% of the total energy consumption of the LHC-9 plant. The more energy efficient the furnace design, the less fuel is needed, which results in lower emissions of air pollutants. Dow's technology selection took into account the efficiency of the cracking furnaces as a key contributor to the overall efficiency of the ethylene plant.

The operational efficiency of the cracking furnaces is dependent on an efficient design and effective operation and maintenance practices. The sections that follow describe the factors that contribute to these key attributes.

Heat Recovery - The efficiency of the cracking furnaces is determined by heat loss to flue gas, process effluent, and firebox walls. To maximize the overall furnace efficiency, all three losses are minimized. The main factor determining the energy efficiency of the cracking furnaces is the effectiveness of the selected design to capture the fired duty for process and steam production use and minimize the losses stated above.

The hot process effluent from the furnace cracking coils is cooled in a series of transfer line exchangers which produce high pressure steam and/or preheat boiler feed water. The process is cooled to the maximum extent possible while avoiding the condensing of heavy process components.

The convection section of the furnace is designed to preheat hydrocarbon feed, dilution steam, and boiler feed water and to superheat the high pressure steam to reduce to the flue gas temperature to the extent that the final exiting flue gas temperature is reduced to its practical limit. The lower practical limit for flue gas is set by margin above acid gas dewpoint and/or practical temperature approach to the streams being preheated.

The wall heat losses are minimized through specification of specialized insulation materials. Proper insulation not only minimizes the heat loss, but also minimizes the furnace firebox outside wall temperatures, an important safety factor for the heater design.

The LHC-9 furnaces will be designed for a thermal efficiency of 93% or higher on a LHV basis (considering stack and wall losses) when cracking feedstock. During start-up and decoking operation the thermal efficiency is limited to a practical limit of 74%, but the firing duty is reduced to approximately 1/3 of normal duty during this time. The 93% thermal efficiency will result in a stack temperature of 290°F or less. The benchmarking data presented will show that the selected design will be an industry leader in furnace thermal efficiency.

Oxygen Trim Control and Good Combustion Practices - The effect of excess air on furnace efficiency is due to the large percentage of nitrogen in the air. This nitrogen absorbs heat from the combusted fuel. Heat not transferred to produce product exhausts to the atmosphere. When excess air increases, larger volumes of nitrogen absorb more heat from the fuel and exhaust the incremental heat to atmosphere. Therefore, furnace efficiency drops as excess air increases. Some excess air must be present to completely combust the fuel. When there is insufficient air present to burn the fuel, partially oxidized fuel will be present. Partially oxidized fuel would be in the form of carbon monoxide and organic carbons that did not fully oxidize to carbon dioxide. The Dow design will include fuel gas composition and heating value analysis and flue gas oxygen analysis to optimize the fuel to air ratio continuously. This will enable Dow to monitor the amount of excess air added to the furnaces and optimize the excess air to provide good combustion and maximum furnace thermal efficiency.

Periodic Tune-Ups and Maintenance- While it is difficult to directly quantify the efficiency benefits of furnace tune-ups and maintenance, the furnaces must be well maintained in order to achieve the design efficiencies stated in the previous section. The furnace operation will be closely monitored and the furnace equipment routinely inspected to maintain efficient operation.

Monitoring and inspection will include:

- Monitoring flue gas temperature, excess oxygen, and carbon monoxide.
- Monitoring temperatures of the flue gas and cracked gas effluent at each heat recovery step.
- Monitoring and trending firing rate relative to feedstock and production.

Routine maintenance and tune-up activities to make corrections on an "as needed" basis will include (but not limited to):

- Process cleaning of transfer line exchangers
- Cleaning, maintenance, and/or replacement of burner tips
- Decoking of furnace coils.
- Maintenance and calibration of oxygen analyzers, temperature measurements, and flow measurements.
- Replacement of the furnace radiant section tubes

The Dow design for LHC-9 provides adequate furnace capacity such that the plant can be operated efficiently at its design capacity while performing routine maintenance activities on a furnace. This allows Dow to better manage maintenance activities and decoking operations, thus minimizing the reduction of furnace efficiency.

Benchmarking Efficiency - In order to select the best available technology for energy efficiency of the Cracking Furnaces and the Recovery Section of LHC-9, Dow carefully evaluated all the available ethylene technologies. In addition to benchmarking each of the available technologies against each other, Dow also benchmarked against Dow's existing ethylene plants and against industry benchmark data.

For industry data, Dow benchmarks using data from Solomon Associates. The Global Olefins Benchmarking Study, conducted by Solomon Associates, is the most comprehensive standard globally by which ethylene plants are benchmarked on all facets of performance, including thermal efficiency. Appendix E contains a letter of statement from Solomon Associates that summarizes the energy performance of the LHC-9 proposed design with other ethylene production plants.

Dow currently has several ethylene plants operating in North America and additional plants internationally. Some of these existing units operate primarily on the same ethane and propane feedstock as LHC-9. This experience not only gives Dow the experience to understand, evaluate, and select the best available technology, it also provides good data for internal benchmarking.

Table 4-1 provides the total energy consumption of the ethylene plant expressed as btu/lb of high-value chemicals (HVC = ethylene, propylene, butadiene, and hydrogen) taking into account all fuel, steam, and electricity consumed in the plant. The technical alternatives studied and Dow's newer plants are very similar in overall energy performance. The older designs have much higher overall energy consumption (lower efficiency). The design selected will have industry leading energy efficiency.

Table 4-2 compares the thermal efficiency on a LHV basis of the cracking furnaces for the technical alternatives studied and Dow's existing plants. As one of the major energy consumers in the ethylene plant, overall plant performance is dependent on an efficient furnace design. The design selected will achieve the highest practical energy efficiency.

Table 4-3 provides a comparison of furnace flue gas stack temperatures for the technical alternatives studied and Dow's existing plants. As the primary source of unrecovered energy in the cracking furnace, the flue gas temperature is the key indicator of furnace efficiency. The design selected by Dow will have the lowest practical stack temperature resulting in high energy efficiency.

With all the above factors considered, Dow has calculated that the ethylene plant will achieve a 24 hour rolling average GHG emissions per lb or ethylene of 1.2 lb/lb and an annual GHG emission rate of 1.1 lb/lb. See the calculations provided below. For the chosen design, the overall GHG emissions per pound of ethylene produced compare closely to EPA's draft permits for other ethylene plants.

597,598 lb/hr CO_2e ÷ 490,000 lb/hr ethylene maximum = 1.2 lb CO_2e / lb ethylene
2,367,999 tpy CO_2e ÷ 2,102,100 tpy ethylene maximum = 1.1 ton CO_2e / ton ethylene

As the benchmarking data demonstrates and as the support letter from Solomon Associates confirms, the technical alternatives selected by Dow will be a leader in energy efficiency for ethane cracking plants.

Table 4-1: Ethylene Plant Energy Efficiency

Design	Overall Plant Specific Energy , (btu/lb HVC)
Chosen Design	6,780
Design A	6,793
Design B	7,322
Existing (1968)	12,339
Existing (1981)	15,241
Existing (1973/2008)	6,994
Existing (1994)	6,915

Table 4-2: Design Cracking Furnace Thermal Efficiency

Design	Thermal Efficiency, (% LHV)
Chosen Design	94%
Design A	94%
Design B	93%
Existing (1968)	85%
Existing (1981)	85/90%
Existing (1973/2008)	93%
Existing (1994)	94%

Table 4-3: Cracking Furnace Stack Temperature

Design	Stack Temperature, (°F)
Chosen Design	271
Design A	270
Design B	285
Existing (1968)	662
Existing (1981)	444
Existing (1973/2008)	271
Existing (1994)	330

4.1.4.2 Low Carbon Gaseous Fuel

CO_2 is a product of combustion generated from any carbon-containing fuel. The preferential use of gaseous fuels such as LHC-9 off gas, resid gas, or natural gas is a method of lowering CO_2 emissions versus the use of solid or liquid fuels.

The off gas from LHC-9 can either be fueled in the LHC-9 furnaces or exported for hydrogen recovery. When operating on off gas, the furnace fuel will have a CO_2 footprint of approximately 51 lb/MM Btu HHV as compared to resid gas at approximately 100 lb/MM Btu HHV or natural gas at 118 lb/MM Btu HHV. These all compare favorably to the use of solid or liquid fuels.

While the export of LHC-9's hydrogen-rich off gas for hydrogen recovery would increase LHC-9's CO_2 emissions, hydrogen recovery from ethylene processes is viable for the industry as a whole. High purity hydrogen is vital to the oil refining business. Hydrogen is necessary for lightening (hydrocracking) and desulfurizing (hydrotreating) of heavy crude oils. While the export of LHC-9 off gas for Hydrogen Recovery would increase the CO_2 production of LHC-9, the industry as a whole benefits as the CO_2 increase of hydrogen recovery is calculated to be less than 80% of the equivalent CO_2 footprint of Steam-Methane Reforming, the most common alternative method in the industry for Hydrogen Production.

LHC-9 will be designed to operate the furnaces on its own off gas. However, because of its importance to the refining industry and the cost of alternative methods of production, the value of chemical hydrogen is higher than its equivalent fuel value. Economic conditions will determine whether the LHC-9 off gas is used for Hydrogen Recovery or for fuel on the LHC-9 furnaces. When this off gas is unavailable or being exported, the alternate fuel will be resid gas and/or natural gas. Resid Gas and natural gas have a fairly low CO_2 emission factors, making them a more attractive secondary fuel with regard to reducing GHG emissions than other liquid or solid fuels. Market conditions for natural gas and hydrogen will influence which fuel is used, therefore substitution of hydrogen for natural gas as an enforceable permit condition is not a viable option. Using off gas fuel in place of natural gas when available and not sold as product is considered to be an acceptable option.

4.1.4.3 Carbon Capture and Storage

CO_2 capture from dilute CO_2 sources such as an ethylene cracker is a relatively new concept. In its March 2011 PSD permitting guidance for GHGs, EPA takes the position that, "for the purpose 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".

These emerging carbon capture and storage (CCS) technologies generally consist of processes that separate CO_2 from combustion process flue gas, compression of the separated CO_2, transportation via pipeline to a site for injection, and then injection into geologic formations such as oil and gas reservoirs, un-mineable coal seams, and underground saline formations.

Of the emerging CO_2 capture technologies that have been identified, amine absorption is the most commercially developed for state-of-the-art large scale CO_2 separation processes. Amine absorption has been applied to processes in the petroleum refining and natural gas processing industries and for exhausts from furnaces. Other potential absorption and membrane technologies are being developed.

Dow is evaluating CCS for the proposed project based on technological, environmental, and economic feasibility.

Table 4-4 Technical Feasibility of CCS Technologies

CCS Component	CCS Technology	Technical Feasibility
Capture and Compression	Post-Combustion	Y
	Pre-Combustion	N
	Oxy-Fuel Combustion	N
	Industrial Separation (natural gas processing, ammonia production)	N
Transportation	Pipeline	Y
	Shipping	Y
Geological Storage	Enhanced Oil Recovery (EOR)	Y
	Gas or Oil Fields	Y
	Saline Formations	Y
	Enhanced Coal Bed Methane Recovery (ECBM)	N
Ocean Storage	Direct Injection (Dissolution Type)	N
	Direct Injection (Lake Type)	N
Mineral Carbonation	Natural Silicate Minerals	N
	Waste Minerals	N
Large Scale CO_2 Utilization/Application		N

CO_2 Capture and Compression - According to the U.S. Department of Energy's National Energy Technology Laboratory (DOE-NETL) separating CO_2 from flue gas streams is challenging for several reasons:

- CO_2 is present at dilute concentrations (13-15 volume percent in coal-fired systems and 3-4 volume percent in gas-fired turbines) and at low pressure (15-25 pounds per square inch absolute [psia]), which dictates that a high volume of gas be treated;

- Trace impurities (particulate matter, sulfur dioxide, nitrogen oxides) as well as oxygen in the flue gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes; and

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

Further, the Obama Administration's Interagency Task Force on Carbon Capture and Storage confirms this in its August 2010 report on the current status of development of CCS systems:

"Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."[3]

Separating CO_2 from the cracking furnaces exhaust streams at the proposed LHC-9 facility is challenging because CO_2 is present in dilute concentrations in the furnace exhaust streams. The exhausts contain 5 vol% or less of CO_2 in the stack gas on an average annual basis. These are not high-purity streams, as recommended in USEPA's guidance. Particulate Matter would potentially have to be removed from the CO_2 stream without causing excessive back pressure on the upstream systems. Additionally, the temperature would have to be reduced prior to separation, compression, and transmission.

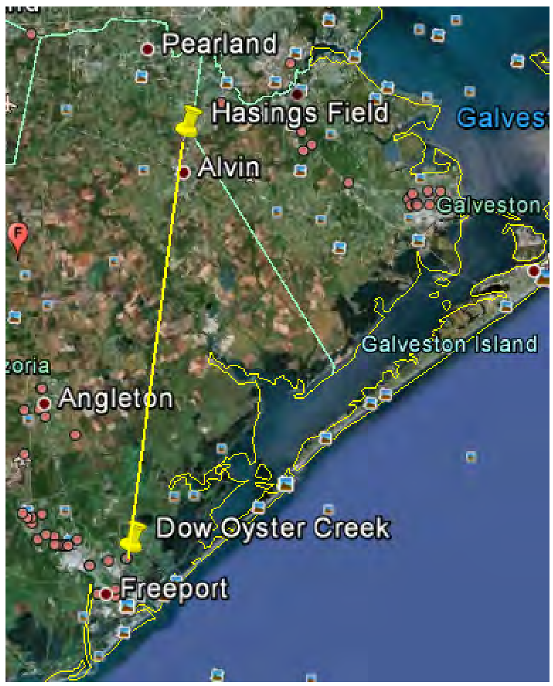
To achieve the necessary CO_2 concentration and temperature for effective sequestration, the recovery and purification of CO_2 from the stack gases would require additional equipment, operating complexity, and increased energy consumption resulting in energy and environmental/air quality penalties. This may, in turn, potentially increase the natural gas fuel use of the plant, with resulting increases in emissions of non-GHG pollutants, to overcome these efficiency losses, or would result in less energy being produced. The Report of the Interagency Task Force on Carbon Capture and Storage has estimated that an energy penalty of as much as 15% would result from inclusion of CO_2 capture (Footnote 2 this page) and would also result in an overall loss of energy efficiency.

[2] DOE-NETL, Carbon Sequestration: FAQ Information Portal, http://www.netl.doe.gov/technologies/carbon_seq/faqs.html

[3] President Obama's Interagency Task Force on Carbon Capture and Storage, *Report of the Interagency Task Force on Carbon Capture and Storage,* August 2010, p. 50.

CO_2 Transport – Once the CO_2 is segregated from the furnaces exhaust, it will require compression to the pressure of the proposed CO_2 pipeline and the high volume stream would need to be transported via pipeline to a geologic formation capable of long-term storage. This would require significant additional inputs of energy as the CO_2 gas must be compressed to CO_2 liquid which is equivalent to a pressure of approximately 2,000 pounds per square inch absolute (psia).

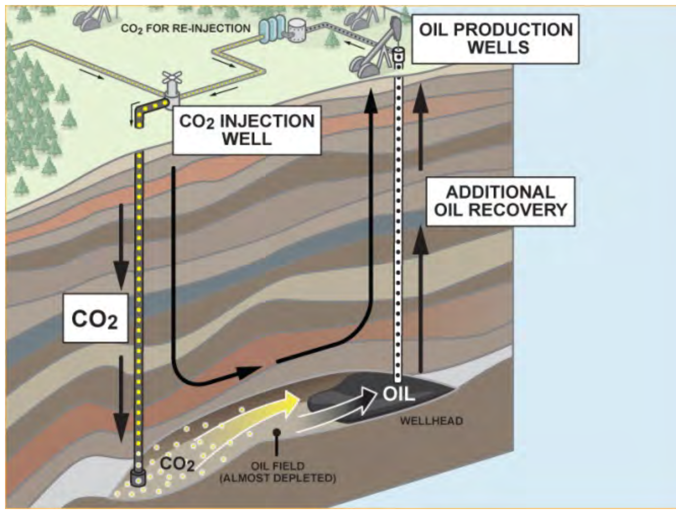
The capabilities for CO_2 storage in the vicinity around Freeport are in early development and are tenuous with regard to commercial viability and demonstration of large-scale, long-term storage; therefore, the capital and legal risks of building infrastructure solely for CO_2 storage from this LHC-9 project are unreasonable. However, if a pipeline was constructed, Denbury Resources owns and operates the Green Pipeline that crosses the Galveston Bay and has a terminus point at the Hastings Field[4]. The Hastings Field EOR site is approximately 40 miles from Dow Freeport; however, there is no existing connection to the pipeline for Hastings Field.



Other potential sequestration sites, which are presently commercially viable, are in the range of 400 to 500 miles from the proposed project site. Assuming it can be demonstrated that those sequestration sites could indefinitely store a substantial portion of the large volume of CO_2 generated by the proposed project, a very long and sizable pipeline would have to be constructed to transport the large volume of high-pressure CO_2 from the plant to the potential storage facility. Based on site specific estimates from the Dow Pipeline organization, typical pipeline costs for installation (including labor) would be $1,500,000-$1,800,000 million/mile. Thus, the high cost of CO_2 transport via pipelines 50 miles or greater in length would render the project infeasible.

[4] Denbury, Green Pipeline Projects, available at http://www.denbury.com/Corporate-Responsibility/Pipeline-Projects/green-pipeline-project/default.aspx (last visited October 10, 2012).

CO_2 Storage – Once the CO_2 is captured and compressed it must be transported to a suitable sequestration site for storage. The Hastings Oil Field, located north of Alvin, Texas, is in the advanced stage of primary depletion. The field has been characterized for storage and Denbury Resources has been developing the field for CO_2-Enhanced Oil Recovery (EOR). CO_2 is injected into the well dissolving into the oil, causing it to swell. The swelling reduces the surface tension of the oil, allowing it to flow toward producing wells. The following diagram is a representation of how EOR works.[5]



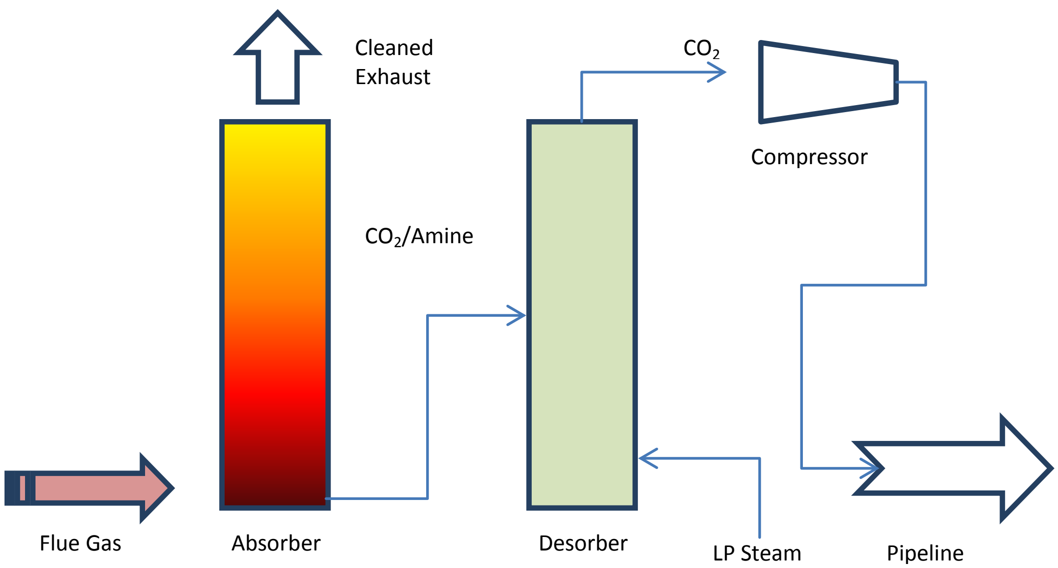
There are other potential storage sites, including enhanced oil recovery (EOR) sites and saline formations that exist in Texas, Louisiana, and Mississippi. These reservoirs and other geologic formation sites are all in early development and are tenuous with regard to commercial viability and demonstration of large-scale, long-term CO_2 storage; therefore the capital cost and legal risks of building infrastructure solely for CO_2 storage from this LHC-9 project are economically challenging. There are salt dome caverns near the project site; however, these limestone formations have not been demonstrated to safely store acid gases such as CO_2, nor is there adequate availability of space. Instead, these domes are used for cyclical storage of liquefied petroleum gases (LPGs) for use in the Gulf Coast as well as for shipment throughout the United States via pipeline. To replace this critical active storage with long-term CO_2 sequestration would jeopardize energy supplies locally and nationally. There are other potential sequestration sites in Texas that are commercially viable, such as the SACROC EOR unit in the Permian Basin. However that location is more than 500 miles from the proposed project site. The closest site that is currently being field-tested to demonstrate its capacity for large-scale geological storage of CO_2 is the Southeast Regional Carbon Sequestration Partnership's (SECARB) Cranfield test site located in Mississippi’s Adams and Franklin Counties. Mississippi is over 400 miles away from the proposed project site. Therefore, both the Texas and Mississippi storage alternatives would be infeasible based on the distance from the project site.

[5] Clean Air Task Force, http://www.fossiltransition.org/

In addition, there are potential environmental impacts that require assessment regarding storage in geologic formations:

- Uncertainty concerning the significance of dissolution of CO_2 into brine;
- Risks of brine displacement resulting from large-scale CO_2 injection, including a pressure leakage risk for brine into underground drinking water sources and/or surface water; and
- Risks to fresh water as a result of leakage of CO_2, including the possibility for damage to the biosphere, underground drinking water sources, and/or surface water, and potential effects on wildlife.

Economic Analysis - Dow understands that CCS is considered to be technically feasible as an add-on control option for the proposed cracking furnaces at Dow's LHC-9 facility. An economic feasibility analysis has been completed for a carbon capture and transport system. Dow has worked to tailor an estimate based on site parameters and the LHC-9 project. The cracker emission rates in the application are based on the maximum potential emissions. This occurs when firing natural gas. More realistically, the units will be burning plant off gas. Therefore, the CCS cost estimate is based on the 1,100,000 tons/yr of CO_2 generated when burning plant off gas. The main elements of the cost analysis include capture, compression, pipeline and storage. The following figure depicts a simplified representation of a CCS system.



The cost estimate includes compression of CO_2 to pipeline pressure of 2000 psi and dry (<500ppm water**)** and a pipeline from Freeport to the Hastings field. The pipe run is approximately 40 miles in length and based on transporting 1,000,000 tons/year of CO_2 in an 8" pipe. Based on site specific estimates from the Dow Pipeline organization, typical pipeline costs for installation (including labor) would be $1,500,000-$1,800,000 per mile. The pipeline capital cost also includes a 15% contingency for Rights of Way (ROW), routing challenges, and variable labor rates. The CCS cost analysis below represents the capital, operating, and maintenance expenses for CCS expressed in annual cost of US dollars. The analysis assumes that the capture efficiency of the CCS system will be 90%.

Detailed CO_2 CCS Effectiveness Evaluation

LHC-9 Parameters	Off Gas Case		
CO_2 Emissions tons/yr	1,113,993		
Vol % CO_2 in Flue Gas	5%		
Assumed % CO_2 Capture	90%		
1) CCS Equipment/ Capital		Units	Off Gas Case
Capture		USD 2012	$ 309,600,000
Tie-ins, duct work			$ 20,400,000
Cooling Tower			$ 28,200,000
Air compressor			$ 4,800,000
Site Development			$ 4,800,000
Total CO_2 Treating Related Capital			$ 367,800,000

2) Pretreatment

No pretreatment is specified at this time.

3) Pipeline Capital and Specifics

Distance to Injection		miles	40
Number Booster Pumps		number	0
Nominal Pipe Diameter		in	8
Pipeline Cost		$/Mi	1,800,000
Pipeline Capital		2012 USD	$ 82,800,000

4) Site Specif Costs (e.g. Operational Costs)

Electricity Cost

compression, MW	10.3		$ 5,289,375
pumping & booster fan, MW	9.1		$ 4,883,476
air compressor, MW	0.4		$ 253,687
Steam required @ 90psig, MW	22.1		$ 15,209,127
SubTotal Electricty Cost		$/yr	$ 25,635,665

Chemical Costs & Services

Demin Water, Inst Air, Plant Air, Nitrogen, Caustic, Antifoam, TEG, Activated Carbon			$ 2,182,082
Waste Water treatment, $/mo	2500		$ 36,000
Amine make up, m^3	1500		$ 5,947,137
SubTotal Chemicals & Services Cost		$/yr	$ 8,165,218

Operations and Maintenance

Capture, Regenerate, Compress			$ 24,244,645
Pipeline			$ 511,853
Well			$ 1,014,354
Pore Space			$ 265,044
SubTotal Operations and Maintenance		$/yr	$ 26,035,896

Other

Tax and Insurance			$ 11,498,774
Measure, Monitor, Verify			$ 1,748,974
SubTotal Other		$/yr	$ 13,247,748

Total of Annual operating expense		$/yr	$ 73,084,528

Detailed CO_2 CCS Effectiveness Evaluation, continued

5) Energy Penalty

Total CCS Required Power		MW	50.3
Energy penalty			21%

6) Comparison of CCS Cost to Project Cost

LHC-9 Capital			24%

7) Avoided Cost

Cost to avoid emission via CCS, averaged over 20 yrs		$/ton	125
Avoided Cost, WITH selling CO_2, averaged over 20 yrs		$/ton	103

selling at $15/ton assumed

8) Associated CO_2

CO_2 generated from Power to capture CO_2			23%

The overall cost effectiveness of a CCS system is estimated to be $125/ton of CO_2 avoided, assuming the CO_2 is stored and not sold. This includes the capital cost for installation, operating cost, and maintenance expenses. In addition, as a result of the implementation of CCS the related energy penalty would be approximately 20%. This energy penalty would necessitate the increased operation of the plants power generation to fulfill the required steam and electrical energy to operate the plant. This would result in an increase in emissions of NO_X, VOC, PM_{10}, $PM_{2.5}$, SO_2, CO, and ammonia. The proposed plant is located in a severe ozone nonattainment area, therefore additional increases of NO_X and VOC would be environmentally detrimental.

Although CCS is considered to be technically feasible, based on the high annualized cost for capture, transport, and storage of the CO_2, CCS as a combined technology is not considered economically feasible for reducing GHG emissions from the furnaces. The extraordinarily high cost would render the proposed project economically unviable if selected. CCS is eliminated as a potential control option in this BACT analysis for CO_2 emissions and is not considered further in this analysis.

4.1.5 Step 5: Select BACT

Dow proposes to incorporate the designs and controls listed above and the practices and standards listed in Table 4-5 as BACT for minimizing CO_2 emissions from the ethylene unit operation. EPA's Good Combustion Practices[6] guidance document was used to develop Table 4-5.

- Efficient Furnace and Recovery Section Design
- Low Carbon Gaseous Fuel
- Oxygen Trim Control and Good Combustion Practices
- Periodic Tune Ups and Maintenance

[6] US Environmental Protection Agency (EPA), *Good Combustion Practices Guidance Document*, available at http://www.epa.gov/ttnatw01/iccr/dirss/gcp.pdf (last visited October 29, 2012).

Table 4-5: Proposed Practices and MRR for Cracking Furnaces

Good Combustion Technique	Practices	Monitoring*	Recordkeeping	Reporting
Heat Recovery	Recover and reuse heat from the cracking furnace.	Continuous monitoring of furnace exhaust temperature.	Records of daily average flue gas temperature	none
Oxygen Trim Control	Utilize the oxygen analyzer to adjust the amount of excess air	Continuous monitoring of furnace exhaust %O_2	Records of daily average furnace exhaust % O_2	none

* Continuous monitoring, continuous record and continuous recorder shall have the same definitions as in the Hazardous Organic NESHAP, 40 CFR 63.152(f) and 63.152(g).

4.2 BACT for Decoking Activities

The cracking furnaces require periodic decoking to remove coke deposits from the furnace tubes. Coke buildup is unavoidable in cracking furnaces and needs to be removed at optimal periods to maintain high furnace efficiency. Decoking is the process of combusting the coke carbon inside the furnace tubes through the use of steam and air. The GHG emissions consist of CO_2 that is produced from combustion of the coke build up on the coils. The estimated annual CO_2 emission rate from decoking of the furnace is negligible compared to the total GHG emissions. However, for completeness, it is addressed in this BACT analysis.

4.2.1 Step 1 – Identify Available Control Technologies

Review of the RBLC database identified no specific BACT controls for GHG emissions from decoking operations. Results of the RBLC search can be found in Appendix D. There are two approaches to minimizing GHG emissions from decoking of the cracking furnace tubes:

1. Minimize coke formation in the furnace tubes
2. Maximize use of air and steam during decoking operation

Coke formation is minimized in 3 primary ways:

- Proper decoke operation to form the chrome oxide layer.
- Proper presulfiding and sulfur addition to passivate the nickel.
- Avoid furnace trips and shutdowns which destroy this chrome oxide layer due to differential thermal expansion of metal and chrome oxide.
- Proper furnace operation to control coke formation by optimum conversion.

4.2.2 Step 2 – Eliminate Technically Infeasible Options

Both of the options listed in Step 1 above are technically feasible.

4.2.3 Step 3 – Rank According to Effectiveness

The control technologies for decoking BACT listed in Step 1 are being proposed for this project. Ranking of these control technologies is not necessary for this application.

4.2.4 Step 4 – Evaluate the Most Effective Controls

Dow proposes a furnace coil selection to minimize coke formation to the maximum extent possible for the cracking furnaces that will be installed at the LHC-9 facility. Managing coke buildup through proper design and operation will result in minimizing the number of decoking activities, resulting in a limited CO_2 formation from decoking operations. The furnace coils are a Ni-Cr (Nickel, Chrome) alloy that are designed for the high tube metal temperatures (1900°F) associated with the thermal cracking process. During decoke operation, the air inside the tubes at high temperature pulls a micro-layer of the chrome to the inner surface of the tube and forms a chrome-oxide layer. This chrome oxide layer is like a ceramic surface that makes the coil surface less active to coke formation than it would be if bare Ni was exposed at the surface.

Reducing the amount of air and/or steam used during the decoking process will reduce the amount of CO_2 emissions, but will increase the amount of CO emissions because the decoking process will convert the coke to CO instead of CO_2. Reducing the amount of air and/or steam could result in an incomplete decoke of the furnace, which will in turn increase the frequency of decoking events. CO is a criteria pollutant; therefore, reducing the amount of air and/or steam is not considered beneficial or an effective method of controlling CO_2 emissions during decoking maintenance since doing so would result in an increase in CO emissions.

The unavoidable requirement to periodically take a cracking furnace off-line for decoking results in loss of production from the furnace. As an economic necessity, it is inherent in the design and operational parameters integrated into the furnace to limit the need for decoking and thus the corresponding CO_2 emissions generated. The cracking furnaces will be designed to ensure good feed quality, conversion control, and heat distribution. These parameters will aid in minimizing coke formation in the furnace, which is the key to reducing CO_2 emissions during decoking activities.

4.2.5 Step 5 – Select BACT

Dow proposes a furnace coil selection with a metallurgy that minimizes coke formation and the optimization of air and steam use during decoking operations as BACT for the decoking activities.

Table 4-6: Proposed Practices and MRR for Decoking Activities

Practices	Monitoring	Recordkeeping	Reporting
Periodic Tune-Ups and Maintenance	Maintenance logs/recordkeeping	Record annual operating hours of decoke	None

4.4 BACT for Flare System

The small elevated flare is designed to control fugitive emissions from process compressor seals. There is also a continuous N_2 and natural gas purge to maintain header velocity and heating value. The pressure-assisted flare manages excess off-gas from LHC-9 operations. This is a necessary pressure control mechanism to address changes in off-gas consumption by other consumer plants at the site. Fuel line purging to safely isolate LHC-9 cracking furnaces burners is routinely flared for OC2L9HH1 – OC2L9HH8. Additionally, there is a continuous natural gas purge to the flare to maintain header velocity. The flare's pilots are fueled by low-carbon pipeline natural gas and are in operation 8,760 hours per year. Both flares will be subject to TCEQ HRVOC and Federal 40 CFR 60.18 requirements.

4.4.1 Step 1 – Identify Available Control Technologies

A search of the RBLC database did not identify any GHG control technologies for control devices such as the small elevated or pressure-assisted flares, particularly since the flares themselves are considered add-on control units. However, to expedite this permit issuance process, Dow considered the following technologies as potential GHG control measures for the flares at the LHC-9 facility:

1. Use of low-carbon assist gas
2. Good flare design and operation
3. Carbon Capture and Storage

4.4.1.1 Low-Carbon Assist Gas

The use of natural gas as assist gas is the lowest-carbon fuel available for the proposed project. Dow proposes to use natural gas for the flares' pilot gas and as supplemental fuel, if needed, to maintain the appropriate vent stream heating value as required by applicable air quality regulations.

4.4.1.2 Good Flare Design and Operation

Good operating and maintenance practices for flares include appropriate maintenance of equipment (such as periodic flare tip maintenance) and operating within the recommended heating value and flare tip velocity as specified by its design. The use of good operating and maintenance practices results in longer life of the equipment and more efficient operation. Therefore, such practices indirectly reduce GHG emissions by supporting operation as designed by the flare manufacturer. Good flare design includes pilot flame monitoring, flow measurement, and monitoring/control of waste gas heating value.

4.4.1.3 Carbon Capture and Storage

The primary source of GHG emissions from a flare is the result of combustion of the hydrocarbon-containing gas stream in the flare. CCS requires separation of CO_2 from the flare exhaust, compression of the CO_2, and transportation to an injection/storage location.

4.4.2 Step 2 – Eliminate Technically Infeasible Options

4.4.2.1 Low-Carbon Assist Gas

Use of low-carbon assist gas is considered technically feasible.

4.4.2.2 Good Flare Design and Operation

Use of good flare design and operation is considered technically feasible.

4.4.2.3 Carbon Capture and Storage

The primary source of GHG emissions from a flare is the result of combustion of the hydrocarbon-containing gas stream in the flare. Flare exhaust cannot be captured for CO_2 separation unless the flare device is enclosed, which poses a safety hazard for a flare system designed for an ethylene production facility. Post-combustion capture is not a feasible control technique for flare exhaust, therefore CCS is considered a technically infeasible option and is not considered further in this BACT analysis.

4.4.3 Step 3 – Rank According to Effectiveness

Use of low-carbon assist gas and good flare design and operation are being proposed for this project. Ranking of these control technologies is not necessary for this application.

4.4.4 Step 4 – Evaluate the Most Effective Controls

Use of low-carbon assist gas and good flare design and operation are being incorporated as control measures therefore an evaluation of the energy, environmental, and economic impacts of the proposed measures is not necessary for this application.

4.4.5 Step 5 – Select BACT

Dow proposes to incorporate low-carbon assist gas and good flare design and operation discussed in Section 4.4.1 as BACT for controlling CO_2 emissions from the flares.

Table 4-7: Proposed Practices and MRR for Flare System

Practices	Monitoring*	Recordkeeping*	Reporting
Good flare design and operation	Continuous monitoring of waste gas heating value and flow rate	Continuous recording of waste gas heating value and flow rate	None
	Continuous monitoring of flare pilot flame	Continuous recording of pilot flame monitoring	None

* Continuous monitoring, continuous record and continuous recorder shall have the same definitions as in the Hazardous Organic NESHAP, 40 CFR 63.152(f) and 63.152(g).

4.5 BACT for the Emergency Generators

The emergency generator engines proposed for use at the LHC-9 facility normally will operate at a low annual capacity factor (approximately one hour per week, and no more than 100 hours per year, per generator) in non-emergency use. Each engine is designed to use diesel fuel, stored in onsite tanks, so that emergency power is available for safe shutdown of the facility in the event of a power outage.

4.5.1 Step 1 – Identify Available Control Technologies

The RBLC database did not identify any add-on GHG control technologies for emergency generator diesel engines. Only good combustion practices were identified in the RBLC as BACT for emergency diesel generators and Dow considered this option in this analysis. Results of the RBLC search can be found in Appendix D.

Good combustion practices for compression ignition engines include appropriate maintenance of equipment (such as periodic testing as will be conducted weekly) and operating within the air to fuel ratio recommended by the manufacturer. Using good combustion practices results in longer life of the equipment and more efficient operation. Therefore, such practices indirectly reduce GHG emissions by supporting operation as designed by the manufacturer.

4.5.2 Step 2 – Eliminate Technically Infeasible Options

Use of good combustion practices is considered technically feasible.

4.5.3 Step 3 – Rank According to Effectiveness

Good combustion practices are the only control option identified in Step 2 and are being proposed for this project.

4.5.4 Step 4 – Evaluate the Most Effective Controls

Dow will incorporate good combustion practices as recommended by the emergency diesel generator manufacturer. An evaluation of the energy, environmental, and economic impacts of the proposed measure is not necessary for this application.

4.5.5 Step 5 – Select BACT

Dow proposes to incorporate good combustion practices discussed in Step 2 of Section 4.5 as BACT for controlling CO_2 emissions from the emergency generators. Further, the new engines will be subject to the federal New Source Performance Standard (NSPS) for Stationary Compression Ignition Internal Combustion Engines (40 CFR Part 60, Subpart IIII). The NSPS has specific emissions standards for various pollutants which must be met during normal operation; therefore, the engine will meet or exceed BACT.

Table 4-8: Proposed Practices and MRR for Emergency Generators

Good Combustion Technique	Practices	Recordkeeping	Reporting
Maintenance practices	Use of documented maintenance procedures	Maintain site specific procedures for maintenance practices	None
	Routinely scheduled inspections and testing	Records of the dates of routine inspections and testing	None

4.6 BACT for Piping Fugitives

The proposed LHC-9 facility will include piping components with GHG fugitive emissions. Fugitive emissions of GHGs from piping will be associated with the plant fuel gas and natural gas lines at the unit. Other process lines in VOC service also may contain GHGs (methane). Emissions from these process lines have not been included in this BACT discussion as existing state and federal air regulations will require instrument leak detection and repair (LDAR) monitoring for any VOC containing process lines, which will also capture the methane component. This BACT discussion is therefore focused on control technologies for the fuel gas / natural gas piping components.

4.6.1 Step 1 – Identify Available Control Technologies

Piping fugitives may be controlled by various techniques, including:

1. Installation of leak-less technology to eliminate fugitive emissions sources;
2. Implementation of instrument leak detection and repair (LDAR) programs in accordance with applicable federal and state regulations and permit conditions;
3. Implementation of alternative monitoring using remote sensing technology such as infrared cameras; and
4. Implementation of audio/visual/olfactory (AVO) leak detection methods.

4.6.2 Step 2 – Eliminate Technically Infeasible Options

4.6.2.1 Leakless Technology

Leakless technology valves are used in situations where highly toxic or otherwise hazardous materials are present. These technologies cannot be repaired without a unit shutdown. Because fuel gas and natural gas are not considered highly toxic or hazardous materials, these fluids do not warrant the risk of unit shutdown for repair. Therefore leakless valve technology for fuel lines is considered technically infeasible.

4.6.2.2 Instrument LDAR Programs

Use of instrument LDAR is considered technically feasible.

4.6.2.3 Remote Sensing

Use of remote sensing measures is considered technically feasible.

4.6.2.4 AVO Monitoring

Emissions from leaking components can be identified through audible, visual, olfactory (AVO) methods. Natural gas and some process fluids may contain mercaptans, making them detectable by olfactory means. Therefore, use of as-observed AVO monitoring is considered technically feasible.

4.6.3 Step 3 – Rank According to Effectiveness

Instrument LDAR programs and the alternative work practice of remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[7]

Since pipeline natural gas is odorized with very small quantities of mercaptan, as-observed olfactory observation is a very effective method for identifying and correcting leaks in natural gas systems. Due to the pressure and other physical properties of plant fuel gas, as-observed audio and visual observations of potential fugitive leaks are accordingly moderately effective.

4.6.4 Step 4 – Evaluate the Most Effective Controls

Due to the negligible amount of GHG emissions from process fugitives, the only feasible control technology is the implementation of an LDAR program as BACT. Dow will implement TCEQ's 28 VHP LDAR program for piping components in methane service – this is primarily the natural gas and fuel gas lines to the furnaces.

While remote sensing using an infrared camera can detect leaks, it is not effective in quantifying the size or concentration of the leak. Additionally, instrument LDAR will be implemented at the facility as a requirement of the TCEQ state air permit, and relevant state and federal air regulations. Using remote sensing equipment to detect fugitive emissions from piping components is not feasible because of the availability and ease of implementation associated with instrument LDAR.

4.6.5 Step 5 – Select BACT

Dow proposes to incorporate an instrument LDAR program for piping components in methane service. The proposed LDAR program will align with the current TCEQ 28 VHP program. A copy of the typical permit conditions for 28 VHP can be found in Appendix D. The proposed LDAR program more than satisfies the BACT requirements when monitoring for methane.

Table 4-9: Proposed Practices and MRR for Piping Fugitives

Practices	Monitoring	Recordkeeping	Reporting
Leak detection and repair, TCEQ 28VHP	Quarterly monitoring of valves and connectors	Records of dates, test methods, instrument readings, repair results, justification for delay of repair, and corrective actions taken for all components.	none

[7] 73 *FedReg* 78199-78219, December 22, 2008.

4.7 BACT for Thermal Oxidizer

The thermal oxidizer is the primary control device for vents from the wet air oxidation unit, low pressure process vent streams, and low pressure storage tank vents. The TOX will use natural gas for burner fuel.

4.5.1 Step 1 – Identify Available Control Technologies

The RBLC database did not identify any add-on GHG control technologies for thermal oxidizers. Only good combustion practices were identified in the RBLC as BACT and Dow considered this option in this analysis. Results of the RBLC search can be found in Appendix D. The following technologies were considered as potential GHG emission control methods for the thermal oxidizer:

- Low-carbon fuel(s)
- Good combustion practices and maintenance
- Carbon capture and storage (CCS)

4.5.1.1 Low-Carbon Fuels

The use of natural gas as fuel gas is the lowest-carbon fuel available for the proposed project. Dow proposes to use natural gas for the thermal oxidizer fuel.

4.5.1.2 Good Combustion Practices and Maintenance

Good combustion practices and maintenance include operation of the thermal oxidizer with adequate air flow to ensure good combustion and maintenance of equipment as recommended by the manufacturer. The use of good combustion practices and maintenance results in longer life of the equipment and more efficient operation. Such practices indirectly reduce GHG emissions by supporting operation as designed by the flare manufacturer. Good combustion practices include monitoring of firebox temperature and % oxygen in the thermal oxidizer stack.

4.5.1.3 Carbon Capture and Storage (CCS)

The primary source of GHG emissions from a thermal oxidizer is the result of combustion of the hydrocarbon-containing gas stream. CCS requires separation of CO_2 from the exhaust, compression of the CO_2, and transportation to an injection/storage location.

4.5.2 Step 2 – Eliminate Technically Infeasible Options

Use of good combustion practices and low-carbon fuel is considered technically feasible. Carbon capture and storage has been discussed previous permit application documents and will not be repeated in this section.

4.4.2.1 Low-Carbon Assist Gas

Use of low-carbon assist gas is considered technically feasible.

4.4.2.2 Good Flare Design and Operation

Use of good combustion practices and maintenance according to manufactures recommendations is considered technically feasible.

4.4.2.3 Carbon Capture and Storage

The primary source of GHG emissions from a TOX is the result of combustion of the hydrocarbon-containing gas stream. Carbon capture and storage has been discussed in previous permit application documents and will not be repeated in this section.

4.5.3 Step 3 – Rank According to Effectiveness

Use of low-carbon natural gas for thermal oxidizer burner fuel and good combustion practices and maintenance are being proposed for this project. Ranking of these control technologies is not necessary for this application.

4.5.4 Step 4 – Evaluate the Most Effective Controls

Use of low-carbon natural gas and good combustion practices and maintenance are being incorporated as control measures therefore an evaluation of the energy, environmental, and economic impacts of the proposed measures is not necessary for this application.

4.5.5 Step 5 – Select BACT

Dow proposes to incorporate low-carbon natural gas and good combustion practices and maintenance as BACT for controlling CO_2 emissions from the flares.

Table 4-10: Proposed Practices and MRR for Thermal Oxidizer

Practices	Monitoring*	Recordkeeping*	Reporting
Good combustion practices	Continuous monitoring of exhaust % O_2 to ensure adequate air supply for combustion	Continuous recording of %O_2 in the thermal oxidizer stack	None
	Continuous monitoring of TOX firebox temperature	Continuous recording of TOX firebox temperature	None
Maintenance	None	Records of routine maintenance conducted on the TOX	None

* Continuous monitoring, continuous record and continuous recorder shall have the same definitions as in the Hazardous Organic NESHAP, 40 CFR 63.152(f) and 63.152(g).

Table 4-11 GHG Emissions Summary
Annual Facility Emission Limits and BACT Selection
Permit Application for a New Facility - LHC-9 Unit

EPN	FIN	Description	GHG Mass Basis Emission Rates		CO_2e	BACT Selection
			Pollutant	Ton per Year	Ton per Year	
OC2H121	OC2L9H121	Cracking Furnace, F-121	CO2	278,357	278,627	Flue Gas Exit Temperature ≤ 330° F. Fuel for the furnace will have ≤ 0.74 lbs carbon per lb fuel (CC). Fuel rate not to exceed 598 MMBtu/hr. Annual output based limit of 1.1 lbs GHG/lbs of ethylene.
			CH4	5.19		
			N2O	0.52		
OC2H122	OC2L9H122	Cracking Furnace, F-122	CO2	278,357	278,627	
			CH4	5.19		
			N2O	0.52		
OC2H123	OC2L9H123	Cracking Furnace, F-123	CO2	278,357	278,627	
			CH4	5.19		
			N2O	0.52		
OC2H124	OC2L9H124	Cracking Furnace, F-124	CO2	278,357	278,627	
			CH4	5.19		
			N2O	0.52		
OC2H125	OC2L9H125	Cracking Furnace, F-125	CO2	278,357	278,627	
			CH4	5.19		
			N2O	0.52		
OC2H126	OC2L9H126	Cracking Furnace, F-126	CO2	301,855	302,148	Flue Gas Exit Temperature ≤ 330° F. Fuel for the furnace will have ≤ 0.74 lbs carbon per lb fuel (CC). Fuel rate not to exceed 599 MMBtu/hr. Annual output based limit of 1.1 lbs GHG/lbs of ethylene.
			CH4	5.63		
			N2O	0.56		
OC2H127	OC2L9H127	Cracking Furnace, F-127	CO2	301,855	302,148	
			CH4	5.63		
			N2O	0.56		
OC2H128	OC2L9H128	Cracking Furnace, F-128	CO2	301,855	302,148	
			CH4	5.63		
			N2O	0.56		
OC2F597	OC2L9F597	Low Pressure Flare, FS-597	CO2	14,034	14,046	Use of good combustion practices.
			CH4	0.22		
			N2O	0.02		
OC2F5961	OC2L9F596	Pressure-Assisted Flare, GF-596	CO2	43,910	44,085	Use of good combustion practices.
			CH4	2.13		
			N2O	0.42		
OC2FU2	OC2L9FU2	Process Area Fugitives	CO2	0.02	80.31	Use of 28VHP LDAR TCEQ program
			CH4	3.82		
OC2GE1	OC2L9GE1	Backup Diesel Generator No. 1	CO2	16.04	16.10	Use of good combustion practices.
			CH4	0.001		
			N2O	0.0001		
OC2GE2	OC2L9GE2	Backup Diesel Generator No. 2	CO2	16.04	16.10	
			CH4	0.001		
			N2O	0.0001		
OC2TOX	OC2L9TOX	LHC-9 TOX	CO2	3,319	3,322	Use of good combustion practices.
			CH4	0.06		
			N2O	0.007		

SECTION 5.0 OTHER PSD REQUIREMENTS

5.1 Impacts Analysis

An impacts analysis is not being provided with this application in accordance with EPA's document *PSD and Title V Permitting Guidance for Greenhouse Gases, March. 2011(Pages 47& 48)*:

"Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause or contribute to a violation of the NAAQS are not applicable to GHGs. Thus, we do not recommend that PSD applicants be required to model or conduct ambient monitoring for CO_2 or GHGs".

5.2 GHG Preconstruction Monitoring

A pre-construction monitoring analysis for GHG is not being provided with this application in accordance with EPA's document *PSD and Title V Permitting Guidance for Greenhouse Gases, March. 2011(Page 48):*

"Monitoring for GHGs is not required because EPA regulations provide an exemption in sections 52.21(i)(5)(iii) and 51.166(i)(5)(iii) for pollutants that are not listed in the appropriate section of the regulations, and GHGs are not currently included in that list. However, it should be noted that sections 52.21(m)(1)(ii) and 51.166(m)(1)(ii) of EPA's regulations apply to pollutants for which no NAAQS exists. These provisions call for collection of air quality monitoring data "as the Administrator determines is necessary to assess ambient air quality for that pollutant in any (or the) area that the emissions of that pollutant would affect." In the case of GHGs, the exemption in sections 52.21(i)(5)(iii) and 51.166(i)(5)(iii) is controlling since GHGs are not currently listed in the relevant paragraph. Nevertheless, EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs."

5.3 Additional Impacts Analysis

A PSD additional impacts analysis is not being provided with this application in accordance with EPA's document *PSD and Title V Permitting Guidance for Greenhouse Gases, March. 2011(Page 48):*

"Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs."

5.4 Endangered Species Act

EPA permitting of this Project is a federal action requiring compliance with Section 7 of the Endangered Species Act (ESA). EPA Region 6 has determined that a biological assessment (BA) is required to determine whether a proposed activity under the authority of a Federal action agency is likely to adversely affect listed species, proposed species, or designated critical habitat. Dow has retained the services of URS Corporation to prepare a BA that evaluates the project's Action Area for federally-protected species and/or their potential habitat and to provide an evaluation of the project's potential to affect federally protected species. Dow will submit a separate report regarding the results of the BA once the assessments have been completed. The report was submitted on March 21, 2013.

5.5 Magnuson-Stevens Fishery Conservation and Management Reauthorization Act

EPA Region 6 has determined that the Project is subject to compliance and the provisions of the Magnuson-Stevens Fishery Conservation and Management Act (MSFCMA), as amended. The MSFCMA, as amended by the Sustainable Fisheries Act of 1996 (Public Law 104-267), requires Federal agencies to consult with the National Marine Fisheries Service (NMFS) on activities that may adversely affect Essential Fish Habitat (EFH). As defined by 16 USC 1802(10), EFH constitutes those aquatic and associated land areas, specifically enumerated as the water way substrate, water column, and water properties required for any life cycle stage for aquatic organisms. EPA has requested that an EFH Assessment be prepared for project's in the vicinity of EFH or with the likelihood of impacting EFH. Dow has retained the services of URS Corporation to prepare an EFH Assessment to evaluate the potential for the Project to affect designated EFH area adjacent to the project. Dow will submit a separate report regarding the results of the EFH Assessment once the assessments have been completed. The report was submitted on March 21, 2013.

5.6 National Historic Preservation Act

EPA Region 6 has determined, in accordance with Advisory Council on Historic Preservation regulations pertaining to historic properties protection (36 CFR 800.4), that the project is subject to the provisions of Section 106 of the National Historic Preservation Act (NHPA) of 1966 (as amended). Section 106 of the NHPA requires federal agencies take into account the effect that an undertaking will have on historic properties. Historic properties are those included in, or eligible for inclusion in, the National Register of Historic Places (NRHP) and may include archeological sites, buildings, structures, sites, objects, and districts. Dow has retained URS Corporation to conduct the required cultural resources review, and will submit a separate cultural report for the results of that review. The purpose of the review is to identify any historic properties that might be adversely affected by the proposed undertaking. Dow will submit a separate report regarding the results of the cultural resources review once the assessments have been completed. The cultural report was submitted on March 21, 2013. The cultural report will aid in the EPA's Section 106 consultation with the Texas Historical Commission.

Appendix A
Forms

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: **The Dow Chemical Company – Freeport, Texas RN: 100225945**		
Texas Secretary of State Charter/Registration Number (*if applicable*): **13812851288**		
B. Company Official Contact Name: **Johnny Chavez Jr.**		
Title: **Responsible Care Leader**		
Mailing Address: **2301 N. Brazosport Blvd., APB Building**		
City: **Freeport**	State: **Texas**	ZIP Code: **77541-3257**
Telephone No.: **(979) 238- 9978**	Fax No.: **(979) 238-0317**	E-mail Address: **txles@dow.com**
C. Technical Contact Name: **Cheryl Steves**		
Title: **Environmental Manager**		
Company Name: **The Dow Chemical Company – Freeport, Texas**		
Mailing Address: **2301 N. Brazosport Blvd., Building B-101**		
City: **Freeport**	State: **Texas**	ZIP Code: **77541-3257**
Telephone No.: **(979) 238-5832**	Fax No.: **(979) 238-0317**	E-mail Address: **clsteves@dow.com**
D. Site Name: **Dow Texas Operations – Freeport**		
E. Area Name/Type of Facility: **Light Hydrocarbons Facility 9**	☒ Permanent ☐ Portable	
F. Principal Company Product or Business: **Chemical Manufacturing Plant**		
Principal Standard Industrial Classification Code (SIC): **2869**		
Principal North American Industry Classification System (NAICS): **325110**		
G. Projected Start of Construction Date: **January 2014**		
Projected Start of Operation Date: **January 2017**		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: **2301 N. Brazosport Boulevard**		
City/Town: **Freeport**	County: **Brazoria**	ZIP Code: **77541-3257**
Latitude (nearest second): **28°58'40"**	Longitude (nearest second): **95°20'57 W**	

I. Applicant Information (continued)	
I. Account Identification Number (leave blank if new site or facility): **BL-0082-R**	
J. Core Data Form.	
Is the Core Data Form (Form 10400) attached? If *No*, provide customer reference number and regulated entity number (complete K and L).	☐ YES ☒ NO
K. Customer Reference Number (CN): **CN600356976**	
L. Regulated Entity Number (RN): **RN100225945**	
II. General Information	
A. Is confidential information submitted with this application? If *Yes*, mark each **confidential** page **confidential** in large red letters at the bottom of each page.	☐ YES ☒ NO
B. Is this application in response to an investigation or enforcement action? If *Yes*, attach a copy of any correspondence from the agency.	☐ YES ☒ NO
C. Number of New Jobs: **25-50**	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
Senator: **Hon. Mike Jackson, Hon. Joan Huffman**	District No.: **11, 17**
Representative: **Hon. Dennis Bonnen**	District No.: **25**
III. Type of Permit Action Requested	
A. Mark the appropriate box indicating what type of action is requested. Initial ☒ Amendment ☐ Revision (30 TAC 116.116(e)) ☐ Change of Location ☐ Relocation ☐	
B. Permit Number (if existing):	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* Construction ☒ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Prevention of Significant Deterioration ☒ Hazardous Air Pollutant Major Source ☐ Plant-Wide Applicability Limit ☐ Other:____________	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

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

III. Type of Permit Action Requested (continued)

H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*

2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. (check all that apply)

GOP Issued ☐	GOP application/revision application submitted or under APD review ☐
SOP Issued ☒	SOP application/revision application submitted or under APD review ☒

IV. Public Notice Applicability

A.	Is this a new permit application or a change of location application?	☒ YES ☐ NO
B.	Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ NO
C.	Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☐ YES ☒ NO
D.	Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☐ YES ☒ NO

If *Yes*, list the affected state(s) and/or Class I Area(s).

E.	Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3. **No**	
1.	Is there any change in character of emissions in this application?	☐ YES ☐ NO
2.	Is there a new air contaminant in this application?	☐ YES ☐ NO
3.	Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO

F. List the total annual emission increases associated with the application (*list* **all** *that apply and attach additional sheets as needed*):

Volatile Organic Compounds (VOC):	59.54 tons/year
Sulfur Dioxide (SO_2):	11.24 tons/year
Carbon Monoxide (CO):	745.63 tons/year
Nitrogen Oxides (NO_x):	206.51 tons/year
Particulate Matter (PM):	98.71 tons/year
PM $_{10}$ microns or less (PM_{10}):	88.00 tons/year
PM $_{2.5}$ microns or less ($PM_{2.5}$):	82.15 tons/year
Lead (Pb):	0.08 tons/year
Hazardous Air Pollutants (HAPs):	tons/year
Other speciated air contaminants **not** listed above:	tons/year

V. Public Notice Information (complete if applicable)		
A. Public Notice Contact Name: **Cheryl Steves**		
Title: **Environmental Manager**		
Mailing Address: **2301 N. Brazosport Blvd., Building B-101**		
City: **Freeport**	State: **Texas**	ZIP Code: **77541**
Telephone No.: **(979) 238- 5832**		
B. Name of the Public Place: **Freeport Public Library**		
Physical Address (No P.O. Boxes): **410 Brazosport Blvd.**		
City: **Freeport**	County: **Brazoria**	ZIP Code: **77541**
The public place has granted authorization to place the application for public viewing and copying.		☒ YES ☐ NO
The public place has internet access available for the public.		☒ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits		
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable: **E. J. "Joe" King**		
Mailing Address: **111 East Locust Street**		
City: **Angleton**	State: **Texas**	ZIP Code: **77515**
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? *(For Concrete Batch Plants)*		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
3. Provide the name, mailing address of the chief executive of the city for the location where the facility is or will be located.		
Chief Executive: **Mayor Norma Moreno Garcia**		
Mailing Address: **200 West 2nd Street**		
City: **Freeport**	State: **Texas**	ZIP Code: **77541**

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

VII. Technical Information				
B. Are any schools located within 3,000 feet of this facility?				☐ YES ☒ NO
C. Maximum Operating Schedule:				
Hours: **24**	Day(s): **7**	Week(s): **52**	Year(s):	
Seasonal Operation? If Yes, please describe in the space provide below.				☐ YES ☒ NO
D. Have the planned MSS emissions been previously submitted as part of an emissions inventory?				☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.				
E. Does this application involve any air contaminants for which a *disaster review* is required?				☐ YES ☒ NO
F. Does this application include a pollutant of concern on the *Air Pollutant Watch List (APWL)*?				☐ YES ☒ NO

VIII. State Regulatory Requirements **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment**. *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*	
A. Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?	☒ YES ☐ NO
B. Will emissions of significant air contaminants from the facility be measured?	☒ YES ☐ NO
C. Is the Best Available Control Technology (BACT) demonstration attached?	☒ YES ☐ NO
D. Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?	☒ YES ☐ NO

IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
A. Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?	☒ YES ☐ NO
B. Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?	☒ YES ☐ NO
C. Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO

IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** ***The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.***		
D. Do nonattainment permitting requirements apply to this application?		☐ YES ☒ NO
E. Do prevention of significant deterioration permitting requirements apply to this application?		☒ YES ☐ NO
F. Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?		☐ YES ☒ NO
G. Is a Plant-wide Applicability Limit permit being requested?		☐ YES ☒ NO
X. Professional Engineer (P.E.) Seal		
Is the estimated capital cost of the project greater than $2 million dollars?		☒ YES ☐ NO
If *Yes*, submit the application under the seal of a Texas licensed P.E.		
XI. Permit Fee Information		
Check, Money Order, Transaction Number ,ePay Voucher Number:	Fee Amount: $ **75,000**	
Company name on check: **The Dow Chemical Company**	Paid online?: ☐ YES ☒ NO	
Is a copy of the check or money order attached to the original submittal of this application?	☒ YES ☐ NO ☐ N/A	
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☒ YES ☐ NO ☐ N/A	

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

XII. Delinquent Fees and Penalties
This form **will not be processed** until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.
XIII. Signature
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name: **Cheryl Steves, EnvironmentalManager**
Signature: Cheryl Steves *Original Signature Required*
Date: November 28, 2012

TABLE 2 MATERIAL BALANCE - LHC 9

List EVERY material involved in each of the following groups. External inlets & outlets only Internal streams are not shown	Point No. From Flow Diagram	Average Process Rate (lb/hr or SCFM) Standard Conditions: 70F, 14.7 psia. Check appropriate column at right for each process	MEAS	EST	CALC
1. Raw Material - Input					
Ethane Feedstock		630,000 lb/hr maximum		x	
Propane Feedstock		280,000 lb/hr maximum		x	
Crude Ethane		30,000 lb/hr average		x	
Crude Ethylene		75,000 lb/hr maximum		x	
Crude C4's		45,000 lb/hr maximum		x	
Crack Gas		200,000 lb/hr maximum		x	
Condensate		400,000 lb/hr maximum		x	
Caustic		10,000 lb/hr maximum		x	
Additives		5,000 lb/hr average		x	
Steam		1,000,000 lb/hr maximum		x	
2. Fuels - Input					
Resid/Offgas		150,000 lb/hr maximum		x	
Natural Gas		180,000 lb/hr maximum		x	
3. Products & Byproducts - Output					
Ethylene		490,000 lb/hr maximum		x	
Mixed C3 Product		100,000 lb/hr maximum		x	
Mixed C4 Product		60,000 lb/hr maximum		x	
Off Gas		150,000 lb/hr maximum		x	
Pygas		45,000 lb/hr maximum		x	
Steam		450,000 lb/hr maximum		x	
4. Solid Wastes - Output					
Carbon (filter media, dilution stm solids)		12 lb/hr average		x	
5. Liquid Wastes - Output					
Wastewater		450,000 lb/hr maximum		x	
6. Airborne Waste (Solid)					
PM		See Table 1(a)			
7. Airborne Waste (Gaseous)					
Furnaces		See Table 1(a)			
Flares					
Tanks					
Cooling Water Tower					
Fugitives					

Note: Maximum values are representative of a range of feedstocks (Ethane/Propane) and do not necessarily occur simultaneously.

TABLE 1F
GHG PSD Applicability Summary

Permit No.: TBD	Application Submittal Date: November 28, 2012
Company: Dow Chemical Company	
Facility Location: Freeport Texas	
City: Freeport	County: Brazoria
Permit Unit I.D.: Cracking Furnaces, Flares, Piping Fugitives, Thermal oxidizer, and Emergency Generator	Permit Name: LHC-9 Facility GHG PSD
Permit Activity: ☒ New Source ☐ Modification	
Project or Process Description: Light Hydrocarbon Plant No. 9 (LHC-9)	

Complete for all Pollutants with a Project Emission Increase.	**POLLUTANTS**						
	Ozone		**CO**	**PM_{10}**	**NO_X**	**SO_2**	**Other[1] CO_2e**
	VOC	**NO_X**					
Nonattainment? (yes or no)	**YES**	**YES**	**NO**	**NO**	**NO**	**NO**	**NO**
Existing site PTE (tpy)?	**>100**	**>100**	**>100**	**>100**	**>100**		**>100,000**
Proposed project emission increases (tpy)	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**>100,000**
Is the existing site a major source? [2] If not, is the project a major source by itself?	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**Yes**
If site is major, is project increase significant?	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**Yes**
If netting required, estimated start of construction?	**January 1, 2014** (Netting not relied upon for this permit)						
Five years prior to start of construction	**January 1, 2009**						
Estimated start of operation	**January 2017**						
Net contemporaneous change, including proposed project (tpy)							**>100,000**
FNSR APPLICABLE? (yes or no)							**Yes (PSD)**

1 Other PSD pollutants.
2 PSD thresholds are found in 40 CFR § 51.166(b)(1).

TABLE 2F

PROJECT EMISSION INCREASE

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

	Affected or Modified Facilities[(2)] FIN	EPN	Permit No.	Actual Emissions[(3)]	Baseline Emissions[(4)] (A)	Proposed Emissions[(5)] (B)	Projected Actual Emissions	Difference (B-A)[(6)]	Correction[(7)]	Project Increase[(8)]
1	OC2L9H121	OC2H121	TBD	-	-	283,737.92		283,737.92		283,737.92
2	OC2L9H122	OC2H122	TBD	-	-	283,737.92		283,737.92		283,737.92
3	OC2L9H123	OC2H123	TBD	-	-	283,737.92		283,737.92		283,737.92
4	OC2L9H124	OC2H124	TBD	-	-	283,737.92		283,737.92		283,737.92
5	OC2L9H125	OC2H125	TBD	-	-	283,737.92		283,737.92		283,737.92
6	OC2L9H126	OC2H126	TBD	-	-	307,690.41		307,690.41		307,690.41
7	OC2L9H127	OC2H127	TBD	-	-	307,690.41		307,690.41		307,690.41
8	OC2L9H128	OC2H128	TBD	-	-	307,690.41		307,690.41		307,690.41
9	OC2L9F596	OC2F5961	TBD	-	-	23,419.31		23,419.31		23,419.31
10	OC2L9F597	OC2F597	TBD	-	-	1,488.69		1,488.69		1,488.69
11	OC2L9CT936	OC2CT936	TBD	-	-	-		-		-
12	OC2L9FU2	OC2FU2	TBD	-	-	72.59		72.59		72.59
13	OC2L9GE1	OC2GE1	TBD	-	-	16.10		16.10		16.10
14	OC2L9GE2	OC2GE2	TBD	-	-	16.10		16.10		16.10
15	OC2L9MEDV151	OC2MEDV151	TBD	-	-	153.15		153.15		153.15
16	OC2L9MEDV153	OC2MEDV153	TBD	-	-	306.29		306.29		306.29
17	OC2L9MEDV155	OC2MEDV155	TBD	-	-	306.29		306.29		306.29
18	OC2L9MEDV157	OC2MEDV157	TBD	-	-	306.29		306.29		306.29
19	OC2L9MEDV159	OC2MEDV159	TBD	-	-	153.15		153.15		153.15
									Page Subtotal[(9)] =	2,367,998.77
									Table Total =	2,367,998.77

All emissions must be listed in tons per year (tpy). The same baseline period must apply for all facilities for a given NSR pollutant.

Footnotes:

1. Individual Table 2F's should be used to summarize the project emission increase for each criteria pollutant.
2. Emission Point Number as designated in NSR Permit or Emissions Inventory.
3. All records and calculations for these values must be available upon request.
4. Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.
5. If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplement.
6. Proposed Emissions (column B) Baseline Emissions (column A).
7. Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement.
8. Obtained by subtracting the correction from the difference. Must be a positive number.
9. Sum all values for this page.

TCEQ

TABLE 3F
PROJECT CONTEMPORANEOUS CHANGES[1]

Company: The Dow Chemical Company
Permit Application Number: TBD — **Criteria Pollutant: CO2e**

	Project Date[2]	Facility Where Change Occured[3] FIN	EPN	Permit No.	Project Name or Activity	Baseline Period	A Baseline Emissions (tons/year)	B Proposed Emissions (tons/year)	Difference (B-A)[5]	Creditable Decrease or Increase[6]
1	6/29/2009	B47C4F1	B47F1	89262	AUTHORIZATION TO SEND PDC HYDROGEN STREAM TO B47FI HYDROGEN FLARE	N/A	-	97.34	97.34	97.34
2	8/17/2009	B78APF1	B78F1	8567	FLARE EMISSIONS	07-08	2,764.78	3,842.25	1,077.47	1,077.47
3	9/3/2009	B20LTXFU10 B20LXCT1 B20LXTX101 B20LXLR1 B20LXLR1 B20LXRX1 B20LXFU2 B20LXFU3 B20LXST1 B20LXST11A B20LXST11B B20LXST28 B20LXST31 B20LXSTD12 B20LXST765 B20LXST32	B20FU10 B20CT1 B20TX101 B20LR1 B20TX101 B20TX101 B20FU2 B20FU3 B20ST1 B20ST11A B20ST11B B20ST28 B20ST31 B20STD12 B20ST765 B20ST32	3320	Latex Shutdown	N/A	2,199.83	-	(2,199.83)	(2,199.83)
4	12/23/2009	A32CSTO500/ A32CSSTO560	A32STHROX/ A32TO560	770	PRYIDINE DERIVATIVES FACILITY	07-08	8,551.74	9,915.67	1,363.93	1,363.93
5	1/5/2010	A30MRML801	A40F100	91437	MARINE LOGISTICS	N/A	-	0.08	0.08	0.08
6	2/2/2010	A153PGT32	A15S10	9045	POWER 3 GAS TURBINES	N/A	488,744.46	-	(488,744.46)	(488,744.46)
7	3/12/2010	A36MDTO520	A36S531	46431	PMDI PLANT	06-07	8,096.75	11,271.30	3,174.55	3,174.55
8	3/12/2010	A36MDF621	A36S621	46431	PMDI PLANT	06-07	45,900.32	94,770.39	48,870.07	48,870.07
9	3/12/2010	A36MDF532	A36F532	46431	PMDI PLANT	06-07	1,444.16	1,936.20	492.04	492.04
10	4/29/2010	B246PGT62	B24S2	9044	THREE GENERAL ELECTRIC GAS TURBINES	N/A	323,644.89	-	(323,644.89)	(323,644.89)
11	6/29/2010	B25P2CT100 B25P2D750 B25P2D750A B25P2LDL101 B25P2LDL103 B25P2DL50A B25P2FU1 B25P2FU2 B25P2FU3 B25P2LR03B B25P2LR109 B25P2PU1 B25P2RX101 B25P2RX101 B25P2RX101 B25P2RX101 B25P2RX101 B25P2RX101 B25P2RX102 B25P2RX102 B25P2RX102 B25P2RX102 B25P2RX102 B25P2RX102 B25P2RX102 B25P2RX102 B25P2RX102 B25P2RX102 B25P2RX102 B25P2RX102 B25P2RX102	B25CT100 B25ST750 B25ST750A B25DL101 B25DLBD103 B25DL750A B25FU1 B25FU2 B25FU3 B25LR03B B25LR109 B27F2 B25RL101 B25RLR101 B25RLS101 B25RLS111 B25VF01 B25VF60 B25RL201 B25RLR102 B25RLS102 B25RLS112 B25RX102 B25SB201 B25SB202 B25SB203 B25SBRB103 B25SBRB104 B25SP102 B25V102 B25VF03	19519 48813	Polyethylene 2 Shutdown	N/A	5,159.18	-	(5,159.18)	(5,159.18)
12	8/6/2010	B42SDTO35	B42TO35	92938	SPC PLANT STYRENE TANK PROJECT	N/A	-	2,322.57	2,322.57	2,322.57
13	8/11/2010	BL7FT01	BL7FT01	83841	MSS	N/A	-	62.39	62.39	62.39
14	10/12/2010	BSRSROE1 or BSRSRMW	BSRFT02 or BSRMW1	93604	SALT DOME OPERATIONS FACILITY	N/A	-	1,201.40	1,201.40	1,201.40
15	11/1/2010	B78APF1	B78F1	8567	AMENDMENT AND RENEWAL	07-08	2,764.78	4,112.42	1,347.64	1,347.64
16	1/6/2011	B45P4F1	B45F1	94180	POLYETHYLENE 4 PLANT REFURBISH PROJECT	06-07	4,754.91	15,226.02	10,471.11	10,471.11

TCEQ

TABLE 3F
PROJECT CONTEMPORANEOUS CHANGES[1]

Company: The Dow Chemical Company

Permit Application Number: TBD | **Criteria Pollutant: CO2e**

	Project Date[2]	Facility Where Change Occured[3] FIN	EPN	Permit No.	Project Name or Activity	Baseline Period	A Baseline Emissions (tons/year)	B Proposed Emissions (tons/year)	Difference (B-A)[5]	Creditable Decrease or Increase[6]
17	2/7/2011	OC1CT73 OC1ST64 OC1U1CT300 OC1U1FU1 OC1U1FU2 OC1U1GE12 OC1U1GE500 OC1U1H201 OC1U1H202 OC1U1H203 OC1U1H204 OC1U1H205 OC1U1RX1 OC1U1RX1 OC1U1RX1 OC1U1RX1 OC1U1RX1 OC1U1TL1 OC1U1TL140 OC9U1FU4	OC1CT73 OC1ST64 OC1CT300 OC1FU1 OC1FU2 OC1GE12 OC1GE500 OC1S201 OC1S202 OC1S203 OC1S204 OC1S205 OC1SV151 OC1SV33 OC1SV400 OC5SV403 OC5SV404 OC1TL1 OC1TL140 OC9FU4	941	EDC VINYL UNIT 1 Shutdown	N/A	58,838.59	-	(58,838.59)	(58,838.59)
18	4/11/2011	OC3DOT01	OC3T01	28363	CHEMICAL MANUFACTURING PLANT	08-09	904.83	1,598.61	693.78	693.78
19	4/11/2011	OCDO3H61	OC3H61	28363	CHEMICAL MANUFACTURING PLANT	08-09	2,449.02	3,330.16	881.14	881.14
20	5/27/2011	BSRRXF01	BSRF401	95672	REGISTRATION FOR ETHYLENE COMPRESSOR C-21	N/A	-	626.13	626.13	626.13
21	8/17/2011	--	OC3T01	83795	DIPHENYL OXIDE PLANT	N/A	-	13,617.33	13,617.33	13,617.33
22	8/25/2011	B46FT850	B46USFT850 (MSS Only)	46429	SPECIALTY POLYURETHANE COPOLYMER PLANT	N/A	-	1,678.00	1,678.00	1,678.00
23	8/25/2011	B42SDTO35	B42TO35	46429	SPECIALTY POLYURETHANE COPOLYMER PLANT	N/A	-	4,344.77	4,344.77	4,344.77
24	9/22/2011	B68RXX2	B70F801	98110	MOLECULAR SIEVE SYSTEM	N/A	-	212.21	212.21	212.21
25	10/3/2011	A32CSTO500/ A32CSTO560	A32STHROX/ A32TO560	98806	DICHLOROPHENOL MANUFACTURING FACILITY	N/A	-	8,932.91	8,932.91	8,932.91
26	10/3/2011	A32CSTO500/ A32CSTO560 (MSS)	A32STHROX/ A32TO560 (MSS)	98806	DICHLOROPHENOL MANUFACTURING FACILITY	N/A	-	4.55	4.55	4.55
27	10/12/2011	B3814RX1	B3808F1	83031	ADD NEW REACTOR R-600	02-03	97.79	3,059.71	2,961.92	2,961.92
28	10/28/2011	OCDO3H61	OC3H61	98680	DIPHENYL OXIDE PLANT	08-09	2,449.02	4,938.88	2,489.86	2,489.86
29	10/28/2011	OCDO3H62	OC3H62	98680	DIPHENYL OXIDE PLANT	08-09	1,984.97	4,938.88	2,953.91	2,953.91
30	3/1/2012	B31S1F1 B31S1HMOD B31S1RX1 B31S1FU1 B31S1FU2 B31S1CT100 B42S1FU23 B42S1ST21A B42S1ST23	B31F1 B31HMOD B31HMOD B31FU1 B31FU2 B31CT100 B42FU1 B42ST21A B42ST23	20432	TXO STYRENE 1 OPS Shutdown	N/A	102,663.07	-	(102,663.07)	(102,663.07)
31	3/1/2012	B42SDTO35	B42TO35	20432	TXO STYRENE DISTRIBUTION OPS Shutdown	N/A	2,322.57	-	(2,322.57)	(2,322.57)
32	3/1/2012	A40SDFSTV A40SDCO8 A40SDFU1 A40SDFU2 A40SDST1 A40SDST2 A40SDST8 A40SDST9 B42SDFU1 B42SDLRN B42SDLRS B42SDLRTT B42SDONS B42SDOSS B42SDST22 B42SDST24 B42SDST25 B42SDST31 B42SDST32	A40FSTV A40TO8 A40FU1 A40FU1 A40FSTV A40FSTV A40TO8 A40FSTV B42FU1 B42EOLRN B42EOLRS B42LRTT B42NS B42SS B42ST22 B42ST24 B42ST25 B42ST31 B42TO35	20432	TXO STYRENE DISTRIBUTION OPS Shutdown	N/A	3,625.67	-	(3,625.67)	(3,625.67)

TCEQ

TABLE 3F
PROJECT CONTEMPORANEOUS CHANGES[1]

Company: The Dow Chemical Company

Permit Application Number: TBD | **Criteria Pollutant: CO2e**

	Project Date[2]	Facility Where Change Occured[3] FIN	EPN	Permit No.	Project Name or Activity	Baseline Period	A Baseline Emissions (tons/year)	B Proposed Emissions (tons/year)	Difference (B-A)[5]	Creditable Decrease or Increase[6]
33	3/1/2012	B71S2F2 B71S2RX1 B71S2B1 B71S2SP4 B71S2H111 B71S2H112 B71S2H121 B71S2F1 B71S2VJ1 B71S2FU1 B71S2SV14 B71S2FU2 B71S2CT100 B71S20S1 B71S2ST11 B71S2ST12 B71S2ST1 B71S2ST2 B71S2ST3 B71S2ST4 B71S2ST5 B71S2ST6 B71S2ST7 B71S2ST9	B71F2 B60F3 B71B1 B71B1 B71S123 B71S123 B71S123 B71F1 B71F2 B71FU1 B71SV14 B71FU2 B71CT100 B71OS1 B71F1 B71F1 B71ST1 B71F1 B71F1 B71F1 B71F1 B71F1 B71F1 B71F1	20432	TXO STYRENE 2 OPS Shutdown	N/A	185,161.05	-	(185,161.05)	(185,161.05)
34	3/7/2012	A17EAF11 A17EAH551 A17EAH555 A17EAF10 A17EARX1 A17EAFU2 A15EAFU3 A15EALRELR A15EALRWLR A15EAST3 A17EACT1 A17EAST145 A17EAST155 A17EAST18 A17EAST19 A17EAST20 A17EAST20X A17EAST28 A17EAST44A A17EAST44B A28EAFUST A28EAST28 A40EAFU1 A40EAST3	A17F11 A17S551 A17S555 A17F10 A17F10 A17FU2 A15FU3 A15LRELR A15LRWLR A15ST3 A17CT1 A17ST145 A17ST155 A17F10 A17F10 A17ST20 A17F10 A17ST28 A17ST44A A17ST44B A28FUST A28ST28 A40FU1 A40ST3	21596	TXO ETHYLBENZENE A OPS Shutdown	N/A	61,700.32	-	(61,700.32)	(61,700.32)
35	4/14/2012	OCU3D3FU	OCD3FU	3434	MRU replacement	10 - 11	-	3,536.00	3,536.00	3,536.00
36	6/1/2012	A32CSTO500 A32CSTO560	A32STHROX A32TO560	770	TXO CHLOR-PYRIDINE: SYM-TET OPS Shutdown	N/A	9,915.67	-	(9,915.67)	(9,915.67)

TABLE 3F
PROJECT CONTEMPORANEOUS CHANGES[1]

Company: The Dow Chemical Company

Permit Application Number: TBD | **Criteria Pollutant: CO2e**

	Project Date[2]	Facility Where Change Occured[3] FIN	EPN	Permit No.	Project Name or Activity	Baseline Period	A Baseline Emissions (tons/year)	B Proposed Emissions (tons/year)	Difference (B-A)[5]	Creditable Decrease or Increase[6]
37	6/1/2012	A32CSF1 A32CSH301 A32CSH200 A32CSFU1 A38CSRX1 A32CSCT200 A32CSPU301 A32CSFU3 A32CSSP214 A32CSST05A A32CSST05B A32CSST1A A32CSST1C A32CSST280 A32CSST284 A32CSCLSYM A32CSPUDIL A32CSRX600 A32CSST331 A32CSRL1 A32CSST25 A32CSTL284 A32CSTL220 A32CSTL229 A32CSTL31G A32CSST13 A32CSFU4	A32F-1 A32H-DTU A32H-NIT A32FU1 A32STHROX A32CT200 A32F-1 A32FU3 A32F-1 A32F-1 A32F-1 A32F-1 A32F-1 A32F-1 A32F-1 A32LR1 A32STHROX A32STHROX A32ST331 A32RL1 A32ST-D25 A32F-1 A32STHROX A32STHROX A32STHROX A32STHROX A32FU1	770	TXO CHLOR-PYRIDINE: SYM-TET OPS Shutdown	N/A	8,934.29	-	(8,934.29)	(8,934.29)
38	1/26/2012	OC4PHH310 OC4PHH320 OC4PHH330 OC4PHH340	OC4H310 OC4H320 OC4H330 OC4H340	100787	PROPANE DEHYDROGENATION UNIT	N/A	-	356,070.47	356,070.47	356,070.47
39	1/26/2012	OC4PHF955	OC4F955	100787	PROPANE DEHYDROGENATION UNIT	N/A	-	35,291.05	35,291.05	35,291.05
40	1/26/2012	OC4PHF956	OC4F956	100787	PROPANE DEHYDROGENATION UNIT	N/A	-	404.77	404.77	404.77
41	1/26/2012	OC4PHF957	OC4F957	100787	PROPANE DEHYDROGENATION UNIT	N/A	-	503.58	503.58	503.58
42	1/26/2012	OC4PHFU2	OC4FU2	100787	PROPANE DEHYDROGENATION UNIT	N/A	-	36.98	36.98	36.98
43	1/26/2012	OC4PHSV485	OC4SV485	100787	PROPANE DEHYDROGENATION UNIT	N/A	-	3,476.76	3,476.76	3,476.76
44	1/26/2012	OC4PHGE860	OC4GE860	100787	PROPANE DEHYDROGENATION UNIT	N/A	-	10.41	10.41	10.41
45	1/26/2012	OC4PHMEFU2	OC4MEFU2	100787	PROPANE DEHYDROGENATION UNIT	N/A	-	0.62	0.62	0.62
46	1/26/2012	OC4PHMEPU	OC4F955	100787	PROPANE DEHYDROGENATION UNIT	N/A	-	27,015.07	27,015.07	27,015.07
47	9/25/2012	OC3DOT01	OC3T01	104727	DPO 3rd reactor	10-11	1,242.26	1,802.87	560.61	560.61
48	9/25/2012	OCDO3H63	OC3H63	104727	DPO 3rd reactor	10-11	-	6,500.00	6,500.00	6,500.00
49	8/30/2012	B255TODCR	B255TODCR	O-02219	R&D B255 DCR PP	N/A	-	9.88	9.88	9.88
									Table Total	-709,616.29
									Project Emission Increase (from Table 2F)	2,367,998.77
Summary of Contemporaneous Changes									**Total (Includes Project Increases):**	1,658,382.48

Footnotes:

1 Individual Table 3Fs should be used to summarize the project emission increase and net emission increase for each criteria pollutant.
2 The start of operation date for the modified or new facilities. Attach Table 4F for each project reduction claimed.
3 Emission Point No. as designated in NSR Permit or Emissions Inventory.
4 All records and calculations for these values must be available upon request.
5 Allowable (Column B) - Baseline (Column A).
6 If portion of the decrease not creditable, enter creditable amount. If all of decrease is creditable or if this line is an increase, enter column C again.

Appendix B
Emissions Calculations

EPN: OC2H121, OC2H122, OC2H123, OC2H124, OC2H125, OC2H126, OC2H127, OC2H128
FIN: OC2L9H121, OC2L9H122, OC2L9H123, OC2L9H124, OC2L9H125, OC2L9H126, OC2L9H127, OC2L9H128
Greenhouse Gas Emissions - Cracking Furnaces, F-121 - F-128

EPN	FIN	Description	Average Heat Input[1] (MMBtu/yr)	Average Fuel Gas Flow[2] (MMscf/yr)	Fuel Type	Fuel Carbon Content[3] (kg C/kg Gas)	Fuel MW[3] (kg/kg-mol)	Emission Factors[4] (kg/MMBtu)		Molar Volume Conversion Factor @ 68F (scf/kg-mol)	Global Warming Potential[5] (100 yr)			Annual Emissions (ton/yr)			
								CH_4	N_2O		CO_2	CH_4	N_2O	CO_2[6]	CH_4[7]	N_2O[7]	CO_2e
OC2H121	OC2L9H121	Cracking Furnace, F-121	4,708,266	4,682	Natural Gas	0.72	17.2	1.0E-03	1.0E-04	849.5	1	21	310	278,357	5.19	0.52	278,627
					Off Gas	0.50	4.9	3.0E-03	6.0E-04					53,819	15.57	3.11	55,111
													Max:	**278,357**	**15.57**	**3.11**	**278,627**
OC2H122	OC2L9H122	Cracking Furnace, F-122	4,708,266	4,682	Natural Gas	0.72	17.2	1.0E-03	1.0E-04	849.5	1	21	310	278,357	5.19	0.52	278,627
					Off Gas	0.50	4.9	3.0E-03	6.0E-04					53,819	15.57	3.11	55,111
													Max:	**278,357**	**15.57**	**3.11**	**278,627**
OC2H123	OC2L9H123	Cracking Furnace, F-123	4,708,266	4,682	Natural Gas	0.72	17.2	1.0E-03	1.0E-04	849.5	1	21	310	278,357	5.19	0.52	278,627
					Off Gas	0.50	4.9	3.0E-03	6.0E-04					53,819	15.57	3.11	55,111
													Max:	**278,357**	**15.57**	**3.11**	**278,627**
OC2H124	OC2L9H124	Cracking Furnace, F-124	4,708,266	4,682	Natural Gas	0.72	17.2	1.0E-03	1.0E-04	849.5	1	21	310	278,357	5.19	0.52	278,627
					Off Gas	0.50	4.9	3.0E-03	6.0E-04					53,819	15.57	3.11	55,111
													Max:	**278,357**	**15.57**	**3.11**	**278,627**
OC2H125	OC2L9H125	Cracking Furnace, F-125	4,708,266	4,682	Natural Gas	0.72	17.2	1.0E-03	1.0E-04	849.5	1	21	310	278,357	5.19	0.52	278,627
					Off Gas	0.50	4.9	3.0E-03	6.0E-04					53,819	15.57	3.11	55,111
													Max:	**278,357**	**15.57**	**3.11**	**278,627**
OC2H126	OC2L9H126	Cracking Furnace, F-126	5,105,726	5,077	Natural Gas	0.72	17.2	1.0E-03	1.0E-04	849.5	1	21	310	301,855	5.63	0.56	302,148
					Off Gas	0.50	4.9	3.0E-03	6.0E-04					58,362	16.88	3.38	59,763
													Max:	**301,855**	**16.88**	**3.38**	**302,148**
OC2H127	OC2L9H127	Cracking Furnace, F-127	5,105,726	5,077	Natural Gas	0.72	17.2	1.0E-03	1.0E-04	849.5	1	21	310	301,855	5.63	0.56	302,148
					Off Gas	0.50	4.9	3.0E-03	6.0E-04					58,362	16.88	3.38	59,763
													Max:	**301,855**	**16.88**	**3.38**	**302,148**
OC2H128	OC2L9H128	Cracking Furnace, F-128	5,105,726	5,077	Natural Gas	0.72	17.2	1.0E-03	1.0E-04	849.5	1	21	310	301,855	5.63	0.56	302,148
					Off Gas	0.50	4.9	3.0E-03	6.0E-04					58,362	16.88	3.38	59,763
													Max:	**301,855**	**16.88**	**3.38**	**302,148**
													Total:	**2,297,351**	**128**	**26**	**2,299,578**

Notes:
1. Based on the annual average heat input (MMBtu/hr) * 8,760 hr/yr
   For Natural Gas:
   MMBtu/yr = 537.47 * 8,760 hr/yr
   MMBtu/yr = 4,708,266
2. Based on the annual average fuel gas rate (Mscf/hr) * 8,760 hr/yr / 1,000
   For Natural Gas:
   MMscf/yr = 534.49 * 8,760 hr/yr / 1,000
   MMscf/yr = 4,682
3. For Fuel Carbon Content and MW data, see LHC-9 Stream Analysis.
4. Factors for ethylene production processes designated in Table C-2 of 40 CFR Part 98 Subpart C .
5. Global Warming Potential from Table A-1 to Subpart A of Part 98.
6. CO_2 emissions calculated in accordance with Tier 3 Calculation Methodology; Equation C-5 of 40 CFR Part 98 Subpart C.
7. CH_4 and N_2O emissions calculated in accordance with Equation C-8 of 40 CFR Part 98 Subpart C.

Example Calculations (From Natural Gas)

CO_2 Emissions:
tpy = MW CO2 (lb/lbmol) / MW CO (lb/lbmol) * Avg. Fuel Flow (MMscf/yr) * 1,000,000 * Fuel Carbon Content (kg C/kg Gas) * (MW of Fuel (lb/lbmol) / Molar Volume Conversion Factor) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = (44/12) * 4,682 (MMscf/yr) * 1,000,000 * 0.72 (kg C/kg Gas) * (17.2 (lb/lbmol) / 849.5 (scf/kg-mol)) * 2.20463 (lb/kg) / 2,000 (lb/ton)
tpy = 278,357

CH_4 Emissions:
tpy = Avg. Heat Input (MMBtu/yr) * CH4 Emission Factor (kg/MMBtu) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = 4,708,266 (MMBtu/yr) * 0.001 (kg/MMBtu) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = 5.19

N_2O Emissions:
tpy = Avg. Heat Input (MMBtu/yr) * N2O Emission Factor (kg/MMBtu) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = 4,708,266 (MMBtu/yr) * 0.0001 (kg/MMBtu) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = 0.52

CO2e Emissions:
tpy = (CO2 Emissions (tpy) * CO2 Global Warming Potential) + (CH4 Emissions (tpy) * CH4 Global Warming Potential) + (N2O Emissions (tpy) * N2O Global Warming Potential)
tpy = (278,357 (tpy) * 1) + (5.19 (tpy) * 21) + (0.52 (tpy) * 310)
tpy = 278,627

EPN: OC2F597
FIN: OC2L9F597
Greenhouse Gas Emissions - Low Pressure Flare, FS-597

EPN	FIN	Description	Average Heat Input[1] (MMBtu/yr)	Average Fuel Gas Flow[2] (MMscf/yr)	Fuel Type	Fuel Carbon Content[3] (kg C/kg Gas)	Fuel MW[3] (kg/kg-mol)	Emission Factors[4] (kg/MMBtu)		Molar Volume Conversion Factor @ 68F (scf/kg-mol)	Global Warming Potential[5] (100 yr)			Annual Emissions (ton/yr)			
								CH_4	N_2O		CO_2	CH_4	N_2O	CO_2[6]	CH_4[7]	N_2O[7]	CO_2e
OC2F597	OC2L9F597	Low Pressure Flare, FS-597	197,855	232	Natural Gas Pilots and Purge	0.72	17.2	1.00E-03	1.00E-04	849.5	1	21	310	13,795	0.22	0.02	13,807
			1,908	274	Routine Vents	0.01	27.7	3.00E-03	6.00E-04					239	0.01	0.00	239
													Total:	**14,034**	**0.22**	**0.02**	**14,046**

Notes:
1. Based on the annual average heat input (MMBtu/hr) * 8,760 hr/yr
For Natural Gas:
MMBtu/yr = 22.59 * 8,760 hr/yr
MMBtu/yr = 197,855
2. Based on the annual average fuel gas rate (scfm) * 60 * 8,760 hr/yr / 1,000,000
For Natural Gas:
MMscf/yr = 441.49 * 60 min/hr * 8,760 hr/yr / 1,000,000
MMscf/yr = 232.05
3. For Fuel Carbon Content and MW data, see LHC-9 Stream Analysis.
4. Factors for ethylene production processes designated in Table C-2 of 40 CFR Part 98 Subpart C .
5. Global Warming Potential from Table A-1 to Subpart A of Part 98.
6. CO_2 emissions calculated in accordance with Tier 3 Calculation Methodology; Equation C-5 of 40 CFR Part 98 Subpart C.
7. CH_4 and N_2O emissions calculated in accordance with Equation C-8 of 40 CFR Part 98 Subpart C.

Example Calculations (From Natural Gas)

CO_2 Emissions:
tpy = MW CO2 (lb/lbmol) / MW CO (lb/lbmol) * Avg. Fuel Flow (MMscf/yr) * 1,000,000 * Fuel Carbon Content (kg C/kg Gas) * (MW of Fuel (lb/lbmol) / Molar Volume Conversion Factor) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = (44/12) * 232.05 (MMscf/yr) * 1,000,000 * 0.72 (kg C/kg Gas) * (17.2 (lb/lbmol) / 849.5 (scf/kg-mol)) * 2.20463 (lb/kg) / 2,000 (lb/ton)
tpy = 13,795

CH_4 Emissions:
tpy = Avg. Heat Input (MMBtu/yr) * CH4 Emission Factor (kg/MMBtu) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = 197,855 (MMBtu/yr) * 0.001 (kg/MMBtu) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = 0.22

N_2O Emissions:
tpy = Avg. Heat Input (MMBtu/yr) * N2O Emission Factor (kg/MMBtu) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = 197,855 (MMBtu/yr) * 0.0001 (kg/MMBtu) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = 0.02

CO2e Emissions:
tpy = (CO2 Emissions (tpy) * CO2 Global Warming Potential) + (CH4 Emissions (tpy) * CH4 Global Warming Potential) + (N2O Emissions (tpy) * N2O Global Warming Potential)
tpy = (13,795 (tpy) * 1) + (0.22 (tpy) * 21) + (0.02 (tpy) * 310)
tpy = 13,807

EPN: OC2F5961
FIN: OC2L9F596
Greenhouse Gas Emissions - Pressure-Assisted Flare, GF-596

EPN	FIN	Description	Average Heat Input[1] (MMBtu/yr)	Average Fuel Gas Flow[2] (MMscf/yr)	Fuel Type	Fuel Carbon Content[3] (kg C/kg Gas)	Fuel MW[3] (kg/kg-mol)	Emission Factors[4] (kg/MMBtu)		Molar Volume Conversion Factor @ 68F (scf/kg-mol)	Global Warming Potential[5] (100 yr)			Annual Emissions (ton/yr)			
								CH_4	N_2O		CO_2	CH_4	N_2O	CO_2[6]	CH_4[7]	N_2O[7]	CO_2e
OC2F5961	OC2L9F596	Pressure-Assisted Flare, GF-596	62,555	61.33	Natural Gas Pilots and Purge	0.72	17.2	1.00E-03	1.00E-04	849.5	1	21	310	3,646	0.07	0.01	3,650
			300,603	324.09	Routine Vents	0.59	19.25	3.00E-03	6.00E-04					17,554	0.99	0.20	17,637
			35,940	35.91	Startup Stream #1	0.76	18.83	3.00E-03	6.00E-04					2,451	0.12	0.02	2,461
			51,013	50.22	Startup Stream #2	0.79	18.04	3.00E-03	6.00E-04					3,422	0.17	0.03	3,436
			6,248	16.51	Startup Stream #3	0.47	4.46	3.00E-03	6.00E-04					163.58	0.02	0.00	165.30
			86,528	56.90	Startup Stream #4	0.83	28.81	3.00E-03	6.00E-04					6,503	0.29	0.06	6,527
			8,418	8.40	Shutdown Stream #1	0.76	18.83	3.00E-03	6.00E-04					574	0.03	0.01	576
			24,272	15.03	Shutdown Stream #2	0.84	30.77	3.00E-03	6.00E-04					1,847	0.08	0.02	1,854
			16,765	13.94	Shutdown Stream #3	0.81	22.11	3.00E-03	6.00E-04					1,188	0.06	0.01	1,192
			6,478	19.25	Shutdown Stream #4	0.19	24.02	3.00E-03	6.00E-04					425	0.02	0.00	427
			10,949	15.01	Maintenance Stream #1	0.76	18.83	3.00E-03	6.00E-04					1,025	0.04	0.01	1,028
			11,424	15.66	Maintenance Stream #2	0.79	18.04	3.00E-03	6.00E-04					1,067	0.04	0.01	1,071
			46,259	63.43	Maintenance Stream #3	0.47	4.46	3.00E-03	6.00E-04					629	0.15	0.03	641
			7,155	9.81	Maintenance Stream #4	0.83	28.81	3.00E-03	6.00E-04					1,121	0.02	0.00	1,123
			7,350	10.08	Maintenance Stream #5	0.86	28.05	3.00E-03	6.00E-04					1,152	0.02	0.00	1,154
			4,863	6.67	Maintenance Stream #6	0.85	42.39	3.00E-03	6.00E-04					1,143	0.02	0.00	1,144
													Total:	**43,910**	**2.13**	**0.42**	**44,085**

Notes:

1. Based on the annual average heat input (MMBtu/hr) * 8,760 hr/yr
   For Natural Gas:
   MMBtu/yr = 7.14 * 8,760 hr/yr
   MMBtu/yr = 62,555
2. Based on the annual average fuel gas rate (scfm) * 60 * 8,760 hr/yr / 1,000,000
   For Natural Gas:
   MMscf/yr = 116.68 * 60 min/hr * 8,760 hr/yr / 1,000,000
   MMscf/yr = 61.33
3. For Fuel Carbon Content and MW data, see LHC-9 Stream Analysis.
4. Factors for ethylene production processes designated in Table C-2 of 40 CFR Part 98 Subpart C .
5. Global Warming Potential from Table A-1 to Subpart A of Part 98.
6. CO_2 emissions calculated in accordance with Tier 3 Calculation Methodology; Equation C-5 of 40 CFR Part 98 Subpart C.
7. CH_4 and N_2O emissions calculated in accordance with Equation C-8 of 40 CFR Part 98 Subpart C.

Example Calculations (From Natural Gas)

CO_2 Emissions:

tpy = MW CO2 (lb/lbmol) / MW CO (lb/lbmol) * Avg. Fuel Flow (MMscf/yr) * 1,000,000 * Fuel Carbon Content (kg C/kg Gas) * (MW of Fuel (lb/lbmol) / Molar Volume Conversion Factor) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = (44/12) * 61 (MMscf/yr) * 1,000,000 * 0.72 (kg C/kg Gas) * (17.2 (lb/lbmol) / 849.5 (scf/kg-mol)) * 2.20463 (lb/kg) / 2,000 (lb/ton)
tpy = 3,646

CH_4 Emissions:

tpy = Avg. Heat Input (MMBtu/yr) * CH4 Emission Factor (kg/MMBtu) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = 62,555 (MMBtu/yr) * 0.001 (kg/MMBtu) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = 0.07

N_2O Emissions:

tpy = Avg. Heat Input (MMBtu/yr) * N2O Emission Factor (kg/MMBtu) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = 62,555 (MMBtu/yr) * 0.0001 (kg/MMBtu) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = 0.01

CO2e Emissions:

tpy = (CO2 Emissions (tpy) * CO2 Global Warming Potential) + (CH4 Emissions (tpy) * CH4 Global Warming Potential) + (N2O Emissions (tpy) * N2O Global Warming Potential)
tpy = (3,646 (tpy) * 1) + (0.07 (tpy) * 21) + (0.01 (tpy) * 310)
tpy = 3,650

EPN: OC2TOX
FIN: OC2L9TOX
Greenhouse Gas Emissions - LHC9 TOX

EPN	FIN	Description	Average Heat Input[1] (MMBtu/yr)	Average Fuel Gas Flow[2] (MMscf/yr)	Fuel Type	Fuel Carbon Content[3] (kg C/kg Gas)	Fuel MW[3] (kg/kg-mol)	Emission Factors[4] (kg/MMBtu)		Molar Volume Conversion Factor @ 68F (scf/kg-mol)	Global Warming Potential[5] (100 yr)			Annual Emissions (ton/yr)			
								CH_4	N_2O		CO_2	CH_4	N_2O	CO_2[6]	CH_4[7]	N_2O[7]	CO_2e
OC2TOX	OC2L9TOX	LHC-9 TOX	52,560	52	Natural Gas	0.72	17.2	1.00E-03	1.00E-04	849.5	1	21	310	3,080	0.06	0.01	3,083
			1,908	274	Routine Vents	0.01	27.7	3.00E-03	6.00E-04					239	0.01	0.00	239
													Total:	**3,319**	**0.06**	**0.01**	**3,322**

Notes:

1. Based on the annual average heat input (MMBtu/hr) * 8,760 hr/yr
   For Natural Gas:
   MMBtu/yr = 6.00 * 8,760 hr/yr
   MMBtu/yr = 52,560
2. Based on the annual average fuel gas rate (Mscf/hr) * 8,760 hr/yr / 1,000
   For Natural Gas:
   MMscf/yr = 5.91 * 8,760 hr/yr / 1,000
   MMscf/yr = 52
3. For Fuel Carbon Content and MW data, see LHC-9 Stream Analysis.
4. Factors for ethylene production processes designated in Table C-2 of 40 CFR Part 98 Subpart C .
5. Global Warming Potential from Table A-1 to Subpart A of Part 98.
6. CO_2 emissions calculated in accordance with Tier 3 Calculation Methodology; Equation C-5 of 40 CFR Part 98 Subpart C.
7. CH_4 and N_2O emissions calculated in accordance with Equation C-8 of 40 CFR Part 98 Subpart C.

Example Calculations (From Natural Gas)

CO_2 Emissions:
tpy = MW CO2 (lb/lbmol) / MW CO (lb/lbmol) * Avg. Fuel Flow (MMscf/yr) * 1,000,000 * Fuel Carbon Content (kg C/kg Gas) * (MW of Fuel (lb/lbmol) / Molar Volume Conversion Factor) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = (44/12) * 52 (MMscf/yr) * 1,000,000 * 0.72 (kg C/kg Gas) * (17.2 (lb/lbmol) / 849.5 (scf/kg-mol)) * 2.20463 (lb/kg) / 2,000 (lb/ton)
tpy = 3,080

CH_4 Emissions:
tpy = Avg. Heat Input (MMBtu/yr) * CH4 Emission Factor (kg/MMBtu) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = 52,560 (MMBtu/yr) * 0.001 (kg/MMBtu) *2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = 0.06

N_2O Emissions:
tpy = Avg. Heat Input (MMBtu/yr) * N2O Emission Factor (kg/MMBtu) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = 52,560 (MMBtu/yr) * 0.0001 (kg/MMBtu) * 2.20462 (lb/kg) / 2,000 (lb/ton)
tpy = 0.01

CO2e Emissions:
tpy = (CO2 Emissions (tpy) * CO2 Global Warming Potential) + (CH4 Emissions (tpy) * CH4 Global Warming Potential) + (N2O Emissions (tpy) * N2O Global Warming Potential)
tpy = (3,080 (tpy) * 1) + (0.06 (tpy) * 21) + (0.01 (tpy) * 310)
tpy = 3,083

EPN: OC2GE1 and OC2GE2
FIN: OC2L9GE1 and OC2L9GE2
Greenhouse Gas Emissions - Backup Diesel Generator No. 1 and No. 2

EPN	FIN	Description	Average Heat Input (MMBtu/yr)	Average Fuel Gas Flow (MMscf/yr)	Fuel Type	Emission Factors[1] (kg/MMBtu)			Global Warming Potential[2] (100 yr)			Annual Emissions (ton/yr)			
						CO_2	CH_4	N_2O	CO_2	CH_4	N_2O	CO_2[3]	CH_4[3]	N_2O[3]	CO_2e
OC2GE1	OC2L9GE1	Backup Diesel Generator No. 1	197	N/A	Diesel	73.96	3.00E-03	6.00E-04	1	21	310	16.04	0.001	0.0001	16.10
											Total :	**16.04**	**0.001**	**0.0001**	**16.10**
OC2GE2	OC2L9GE2	Backup Diesel Generator No. 2	197	N/A	Diesel	73.96	3.00E-03	6.00E-04	1	21	310	16.04	0.001	0.0001	16.10
											Total :	**16.04**	**0.001**	**0.0001**	**16.10**

Notes:
1. Factors for CO2 designated in Table C-1 of 40 CFR Part 98 Subpart C, factors for CH4 and N2O designated in Table C-2 of 40 CFR Part 98 Subpart C .
2. Global Warming Potential from Table A-1 to Subpart A of Part 98.
3. CO2, CH4, and N2O emissions calculated in accordance with Equation C-8 of 40 CFR Part 98 Subpart C.

Example Calculations (From Natural Gas)

CO_2 Emissions:

tpy = Avg. Heat Input (MMBtu/yr) * CO2 Emission Factor (kg/MMBtu) * 2.204 (lb/kg) / 2,000 (lb/ton)
tpy = 197 (MMBtu/yr) * 73.960 (kg/MMBtu) * 2.204 (lb/kg) / 2,000 (lb/ton)
tpy = 16.04

CH_4 Emissions:

tpy = Avg. Heat Input (MMBtu/yr) * CH4 Emission Factor (kg/MMBtu) * 2.204 (lb/kg) / 2,000 (lb/ton)
tpy = 197 (MMBtu/yr) * 0.003 (kg/MMBtu) * 2.204 (lb/kg) / 2,000 (lb/ton)
tpy = 0.001

N_2O Emissions:

tpy = Avg. Heat Input (MMBtu/yr) * N2O Emission Factor (kg/MMBtu) * 2.204 (lb/kg) / 2,000 (lb/ton)
tpy = 197 (MMBtu/yr) * 0.0006 (kg/MMBtu) * 2.204 (lb/kg) / 2,000 (lb/ton)
tpy = 0.0001

CO2e Emissions:

tpy = (CO2 Emissions (tpy) * CO2 Global Warming Potential) + (CH4 Emissions (tpy) * CH4 Global Warming Potential) + (N2O Emissions (tpy) * N2O Global Warming Potential)
tpy = (16.04 (tpy) * 1) + (0.001 (tpy) * 21) + (0.0001 (tpy) * 310)
tpy = 16.10

LHC-9 Stream Analysis

Natural Gas

Component		Wt %	Component MW (lb/lbmol)	Moles	Mol %	Atoms Carbon	Stream MW (lb/lbmol)	Carbon Content (lb/lb fuel)
Hydrogen	H_2	0.00	2.02	0.00	0.00	0	0.00	0.00
Nitrogen	N_2	1.14	28.01	0.04	0.70	0	0.20	0.00
Carbon Dioxide	CO_2	4.09	44.01	0.09	1.60	1	0.70	0.27
Carbon Monoxide	CO	0.00	28.01	0.00	0.00	1	0.00	0.43
Methane	CH_4	87.77	16.04	5.47	94.32	1	15.13	0.75
Ethylene	C_2H_4	0.00	28.05	0.00	0.00	2	0.00	0.86
Ethane	C_2H_6	4.36	30.07	0.15	2.50	2	0.75	0.80
Propane	C_3H_8	1.36	44.10	0.03	0.53	3	0.23	0.82
Butane	C_4H_{10}	0.74	58.12	0.01	0.22	4	0.13	0.83
Pentane	C_5H_{12}	0.54	72.15	0.01	0.13	5	0.09	0.83
		100.0		5.8	100.0			

MW Carbon	12.01	lb/lbmol

Average MW of Natural Gas = 17.2

Average Carbon Content of Natural Gas = 0.72

Off Gas

Component		Wt %	Component MW (lb/lbmol)	Moles	Mol %	Atoms Carbon	Stream MW (lb/lbmol)	Carbon Content (lb/lb fuel)
Hydrogen	H_2	33.22	2.02	16.47	80.14	0	1.62	0.00
Nitrogen	N_2	0.15	28.01	0.01	0.03	0	0.01	0.00
Carbon Dioxide	CO_2	0.55	44.01	0.01	0.06	1	0.03	0.27
Carbon Monoxide	CO	0.29	28.01	0.01	0.05	1	0.01	0.43
Methane	CH_4	64.26	16.04	4.01	19.50	1	3.13	0.75
Ethylene	C_2H_4	0.55	28.05	0.02	0.10	2	0.03	0.86
Ethane	C_2H_6	0.61	30.07	0.02	0.10	2	0.03	0.80
Propane	C_3H_8	0.18	44.10	0.00	0.02	3	0.01	0.82
Butane	C_4H_{10}	0.10	58.12	0.00	0.01	4	0.00	0.83
Pentane	C_5H_{12}	0.07	72.15	0.00	0.00	5	0.00	0.83
		100.0		20.6	100.0			

MW Carbon	12.01	lb/lbmol

Average MW of Off Gas = 4.9

Average Carbon Content of Off Gas = 0.50

Startup Stream #1/Shutdown Stream #1/Maitenance Stream #1

Component		Wt %	Component MW (lb/lbmol)	Moles	Mol %	Atoms Carbon	Stream MW (lb/lbmol)	Carbon Content (lb/lb fuel)
Water	H_2O	4.59	18.02	0.25	4.80	0	0.86	0.00
Carbon Dioxide	CO_2	0.07	44.01	0.00	0.03	1	0.01	0.27
Carbon Monoxide	CO	0.03	28.01	0.00	0.02	1	0.01	0.43
Hydrogen	H_2	3.66	2.02	1.81	34.13	0	0.69	0.00
Methane	CH_4	5.97	16.04	0.37	7.00	1	1.12	0.75
Acetylene	C_2H_2	0.33	26.04	0.01	0.24	2	0.06	0.92
Ethylene	C_2H_4	47.82	28.05	1.70	32.10	2	9.00	0.86
Ethane	C_2H_6	31.57	30.07	1.05	19.76	2	5.94	0.80
Methyl Acetylene	C_3H_4	0.01	40.07	0.00	0.01	3	0.00	0.90
Propadiene	C_3H_5	0.01	40.07	0.00	0.01	3	0.00	0.90
Proylene	C_3H_8	1.13	42.08	0.03	0.51	3	0.21	0.86
Propane	C_3H_8	0.25	44.10	0.01	0.11	3	0.05	0.82
Vinyl Acetylene	C_4H_4	0.04	52.08	0.00	0.02	4	0.01	0.92
1,3-Butadiene	C_4H_6	1.22	54.09	0.02	0.42	4	0.23	0.89
1-Butene	C_4H_8	0.17	56.11	0.00	0.06	4	0.03	0.86
Iso-Butane	C_4H_{10}	0.00	58.12	0.00	0.00	4	0.00	0.83
n-Butane	C_4H_{10}	0.32	58.12	0.01	0.10	4	0.06	0.83
1-Pentene	C_5H_{12}	0.93	67.10	0.01	0.26	5	0.17	0.89
Benzene	C_6H_6	1.39	78.12	0.02	0.33	6	0.26	0.92
Toluene	C_7H_8	0.14	92.14	0.00	0.03	7	0.03	0.91
Styrene	C_8H_8	0.09	104.15	0.00	0.02	8	0.02	0.92
Ethyl Benzene	C_8H_{10}	0.00	106.17	0.00	0.00	8	0.00	0.90
M-Xylene	C_8H_{10}	0.00	106.17	0.00	0.00	8	0.00	0.90
C6 Nonaro	C6 Nonaro	0.10	81.79	0.00	0.02	6	0.02	0.88
C7 Nonaro	C7 Nonaro	0.03	94.54	0.00	0.01	7	0.01	0.89
C8 Nonaro	C8 Nonaro	0.00	110.20	0.00	0.00	8	0.00	0.87
C9 Aro	C9 Aro	0.01	118.19	0.00	0.00	9	0.00	0.91
C9 Nonaro	C9 Nonaro	0.00	127.29	0.00	0.00	9	0.00	0.85
C10s	C10s	0.05	128.58	0.00	0.01	10	0.01	0.93
C11+	C11+	0.05	249.58	0.00	0.00	11	0.01	0.53
Hydrogen Sulfide	H2S	0.01	34.08	0.00	0.01	0	0.00	0.00
		100.0		5.3	100.0			

MW Carbon	12.01	lb/lbmol

Average MW of Startup Stream #1/Shutdown Stream #1 = 18.8

Average Carbon Content of Startup Stream #1/Shutdown Stream #1 = 0.76

Startup Stream #2/Maintenance Stream #2

Component		Wt %	Component MW (lb/lbmol)	Moles	Mol %	Atoms Carbon	Stream MW (lb/lbmol)	Carbon Content (lb/lb fuel)
Water	H_2O	0.00	18.02	0.00	0.00	0	0.00	0.00
Carbon Dioxide	CO_2	0.00	44.01	0.00	0.00	1	0.00	0.27
Carbon Monoxide	CO	0.04	28.01	0.00	0.02	1	0.01	0.43
Hydrogen	H_2	4.10	2.02	2.03	36.60	0	0.74	0.00
Methane	CH_4	6.68	16.04	0.42	7.51	1	1.20	0.75
Acetylene	C_2H_2	0.37	26.04	0.01	0.26	2	0.07	0.92
Ethylene	C_2H_4	53.50	28.05	1.91	34.42	2	9.65	0.86
Ethane	C_2H_6	35.32	30.07	1.17	21.19	2	6.37	0.80
Methyl Acetylene	C_3H_4	0.00	40.07	0.00	0.00	3	0.00	0.90
Propadiene	C_3H_5	0.00	40.07	0.00	0.00	3	0.00	0.90
Proylene	C_3H_8	0.00	42.08	0.00	0.00	3	0.00	0.86
Propane	C_3H_8	0.00	44.10	0.00	0.00	3	0.00	0.82
Vinyl Acetylene	C_4H_4	0.00	52.08	0.00	0.00	4	0.00	0.92
1,3-Butadiene	C_4H_6	0.00	54.09	0.00	0.00	4	0.00	0.89
1-Butene	C_4H_8	0.00	56.11	0.00	0.00	4	0.00	0.86
Iso-Butane	C_4H_{10}	0.00	58.12	0.00	0.00	4	0.00	0.83
n-Butane	C_4H_{10}	0.00	58.12	0.00	0.00	4	0.00	0.83
1-Pentene	C_5H_{12}	0.00	67.10	0.00	0.00	5	0.00	0.89
Benzene	C_6H_6	0.00	78.12	0.00	0.00	6	0.00	0.92
Toluene	C_7H_8	0.00	92.14	0.00	0.00	7	0.00	0.91
Styrene	C_8H_8	0.00	104.15	0.00	0.00	8	0.00	0.92
Ethyl Benzene	C_8H_{10}	0.00	106.17	0.00	0.00	8	0.00	0.90
M-Xylene	C_8H_{10}	0.00	106.17	0.00	0.00	8	0.00	0.90
C6 Nonaro	C6 Nonaro	0.00	81.79	0.00	0.00	6	0.00	0.88
C7 Nonaro	C7 Nonaro	0.00	94.54	0.00	0.00	7	0.00	0.89
C8 Nonaro	C8 Nonaro	0.00	110.20	0.00	0.00	8	0.00	0.87
C9 Aro	C9 Aro	0.00	118.19	0.00	0.00	9	0.00	0.91
C9 Nonaro	C9 Nonaro	0.00	127.29	0.00	0.00	9	0.00	0.85
C10s	C10s	0.00	128.58	0.00	0.00	10	0.00	0.93
		100.0		5.5	100.0			

MW Carbon	12.01	lb/lbmol

Average MW of Startup Stream #2/Maintenance Stream #2 = 18.0

Average Carbon Content of Startup Stream #2/Maintenance Stream #2 = 0.79

Startup Stream #3/Maintenance Stream #3

Component		Wt %	Component MW (lb/lbmol)	Moles	Mol %	Atoms Carbon	Stream MW (lb/lbmol)	Carbon Content (lb/lb fuel)
Water	H_2O	0.00	18.02	0.00	0.00	0	0.00	0.00
Carbon Dioxide	CO_2	0.00	44.01	0.00	0.00	1	0.00	0.27
Carbon Monoxide	CO	0.34	28.01	0.01	0.05	1	0.02	0.43
Hydrogen	H_2	37.51	2.02	18.57	82.75	0	1.67	0.00
Methane	CH_4	61.57	16.04	3.84	17.10	1	2.74	0.75
Acetylene	C_2H_2	0.00	26.04	0.00	0.00	2	0.00	0.92
Ethylene	C_2H_4	0.57	28.05	0.02	0.09	2	0.03	0.86
Ethane	C_2H_6	0.01	30.07	0.00	0.00	2	0.00	0.80
Methyl Acetylene	C_3H_4	0.00	40.07	0.00	0.00	3	0.00	0.90
Propadiene	C_3H_5	0.00	40.07	0.00	0.00	3	0.00	0.90
Proylene	C_3H_8	0.00	42.08	0.00	0.00	3	0.00	0.86
Propane	C_3H_8	0.00	44.10	0.00	0.00	3	0.00	0.82
Vinyl Acetylene	C_4H_4	0.00	52.08	0.00	0.00	4	0.00	0.92
1,3-Butadiene	C_4H_6	0.00	54.09	0.00	0.00	4	0.00	0.89
1-Butene	C_4H_8	0.00	56.11	0.00	0.00	4	0.00	0.86
Iso-Butane	C_4H_{10}	0.00	58.12	0.00	0.00	4	0.00	0.83
n-Butane	C_4H_{10}	0.00	58.12	0.00	0.00	4	0.00	0.83
1-Pentene	C_5H_{12}	0.00	67.10	0.00	0.00	5	0.00	0.89
Benzene	C_6H_6	0.00	78.12	0.00	0.00	6	0.00	0.92
Toluene	C_7H_8	0.00	92.14	0.00	0.00	7	0.00	0.91
Styrene	C_8H_8	0.00	104.15	0.00	0.00	8	0.00	0.92
Ethyl Benzene	C_8H_{10}	0.00	106.17	0.00	0.00	8	0.00	0.90
M-Xylene	C_8H_{10}	0.00	106.17	0.00	0.00	8	0.00	0.90
C6 Nonaro	C6 Nonaro	0.00	81.79	0.00	0.00	6	0.00	0.88
C7 Nonaro	C7 Nonaro	0.00	94.54	0.00	0.00	7	0.00	0.89
C8 Nonaro	C8 Nonaro	0.00	110.20	0.00	0.00	8	0.00	0.87
C9 Aro	C9 Aro	0.00	118.19	0.00	0.00	9	0.00	0.91
C9 Nonaro	C9 Nonaro	0.00	127.29	0.00	0.00	9	0.00	0.85
C10s	C10s	0.00	128.58	0.00	0.00	10	0.00	0.93
		100.0		22.4	100.0			

MW Carbon	12.01	lb/lbmol

Average MW of Startup Stream #3/Maintenance Stream #3 = 4.5

Average Carbon Content of Startup Stream #3/Maintenance Stream #3 = 0.47

Startup Stream #4/Maintenance Stream #4

Component		Wt %	Component MW (lb/lbmol)	Moles	Mol %	Atoms Carbon	Stream MW (lb/lbmol)	Carbon Content (lb/lb fuel)
Water	H_2O	0.00	18.02	0.00	0.00	0	0.00	0.00
Carbon Dioxide	CO_2	0.00	44.01	0.00	0.00	1	0.00	0.27
Carbon Monoxide	CO	0.00	28.01	0.00	0.00	1	0.00	0.43
Hydrogen	H_2	0.00	2.02	0.00	0.00	0	0.00	0.00
Methane	CH_4	0.01	16.04	0.00	0.02	1	0.00	0.75
Acetylene	C_2H_2	0.00	26.04	0.00	0.00	2	0.00	0.92
Ethylene	C_2H_4	60.80	28.05	2.17	62.44	2	17.52	0.86
Ethane	C_2H_6	39.16	30.07	1.30	37.52	2	11.28	0.80
Methyl Acetylene	C_3H_4	0.00	40.07	0.00	0.00	3	0.00	0.90
Propadiene	C_3H_5	0.00	40.07	0.00	0.00	3	0.00	0.90
Proylene	C_3H_8	0.03	42.08	0.00	0.02	3	0.01	0.86
Propane	C_3H_8	0.00	44.10	0.00	0.00	3	0.00	0.82
Vinyl Acetylene	C_4H_4	0.00	52.08	0.00	0.00	4	0.00	0.92
1,3-Butadiene	C_4H_6	0.00	54.09	0.00	0.00	4	0.00	0.89
1-Butene	C_4H_8	0.00	56.11	0.00	0.00	4	0.00	0.86
Iso-Butane	C_4H_{10}	0.00	58.12	0.00	0.00	4	0.00	0.83
n-Butane	C_4H_{10}	0.00	58.12	0.00	0.00	4	0.00	0.83
1-Pentene	C_5H_{12}	0.00	67.10	0.00	0.00	5	0.00	0.89
Benzene	C_6H_6	0.00	78.12	0.00	0.00	6	0.00	0.92
Toluene	C_7H_8	0.00	92.14	0.00	0.00	7	0.00	0.91
Styrene	C_8H_8	0.00	104.15	0.00	0.00	8	0.00	0.92
Ethyl Benzene	C_8H_{10}	0.00	106.17	0.00	0.00	8	0.00	0.90
M-Xylene	C_8H_{10}	0.00	106.17	0.00	0.00	8	0.00	0.90
C6 Nonaro	C6 Nonaro	0.00	81.79	0.00	0.00	6	0.00	0.88
C7 Nonaro	C7 Nonaro	0.00	94.54	0.00	0.00	7	0.00	0.89
C8 Nonaro	C8 Nonaro	0.00	110.20	0.00	0.00	8	0.00	0.87
C9 Aro	C9 Aro	0.00	118.19	0.00	0.00	9	0.00	0.91
C9 Nonaro	C9 Nonaro	0.00	127.29	0.00	0.00	9	0.00	0.85
C10s	C10s	0.00	128.58	0.00	0.00	10	0.00	0.93
		100.0		3.5	100.0			

MW Carbon	12.01	lb/lbmol

Average MW of Startup Stream #4/Maintenance Stream #4 = 28.8

Average Carbon Content of Startup Stream #4/Maintenance Stream #4 = 0.83

Shutdown Stream #2

Component		Wt %	Component MW (lb/lbmol)	Moles	Mol %	Atoms Carbon	Stream MW (lb/lbmol)	Carbon Content (lb/lb fuel)
Water	H_2O	0.00	18.02	0.00	0.00	0	0.00	0.00
Carbon Dioxide	CO_2	0.01	44.01	0.00	0.01	1	0.00	0.27
Carbon Monoxide	CO	0.00	28.01	0.00	0.00	1	0.00	0.43
Hydrogen	H_2	0.19	2.02	0.10	2.94	0	0.06	0.00
Methane	CH_4	0.57	16.04	0.04	1.10	1	0.18	0.75
Acetylene	C_2H_2	0.02	26.04	0.00	0.02	2	0.01	0.92
Ethylene	C_2H_4	51.63	28.05	1.84	56.64	2	15.89	0.86
Ethane	C_2H_6	17.03	30.07	0.57	17.42	2	5.24	0.80
Methyl Acetylene	C_3H_4	0.17	40.07	0.00	0.13	3	0.05	0.90
Propadiene	C_3H_5	0.17	40.07	0.00	0.13	3	0.05	0.90
Proylene	C_3H_8	17.03	42.08	0.40	12.46	3	5.24	0.86
Propane	C_3H_8	12.97	44.10	0.29	9.05	3	3.99	0.82
Vinyl Acetylene	C_4H_4	0.01	52.08	0.00	0.00	4	0.00	0.92
1,3-Butadiene	C_4H_6	0.06	54.09	0.00	0.04	4	0.02	0.89
1-Butene	C_4H_8	0.01	56.11	0.00	0.01	4	0.00	0.86
Iso-Butane	C_4H_{10}	0.00	58.12	0.00	0.00	4	0.00	0.83
n-Butane	C_4H_{10}	0.02	58.12	0.00	0.01	4	0.01	0.83
1-Pentene	C_5H_{12}	0.05	67.10	0.00	0.02	5	0.01	0.89
Benzene	C_6H_6	0.05	78.12	0.00	0.02	6	0.02	0.92
Toluene	C_7H_8	0.00	92.14	0.00	0.00	7	0.00	0.91
Styrene	C_8H_8	0.00	104.15	0.00	0.00	8	0.00	0.92
Ethyl Benzene	C_8H_{10}	0.00	106.17	0.00	0.00	8	0.00	0.90
M-Xylene	C_8H_{10}	0.00	106.17	0.00	0.00	8	0.00	0.90
C6 Nonaro	C6 Nonaro	0.00	81.79	0.00	0.00	6	0.00	0.88
C7 Nonaro	C7 Nonaro	0.00	94.54	0.00	0.00	7	0.00	0.89
C8 Nonaro	C8 Nonaro	0.00	110.20	0.00	0.00	8	0.00	0.87
C9 Aro	C9 Aro	0.00	118.19	0.00	0.00	9	0.00	0.91
C9 Nonaro	C9 Nonaro	0.00	127.29	0.00	0.00	9	0.00	0.85
C10s	C10s	0.00	128.58	0.00	0.00	10	0.00	0.93
C11s+	C11s+	0.00	249.58	0.00	0.00	11	0.00	0.53
		100.0		3.2	100.0			

MW Carbon	12.01	lb/lbmol

Average MW of Shtudown Stream #2 = 30.8

Average Carbon Content of Shutdown Stream #2 = 0.84

Shutdown Stream #3

Component		Wt %	Component MW (lb/lbmol)	Moles	Mol %	Atoms Carbon	Stream MW (lb/lbmol)	Carbon Content (lb/lb fuel)
Water	H_2O	0.46	18.02	0.03	0.56	0	0.10	0.00
Carbon Dioxide	CO_2	0.02	44.01	0.00	0.01	1	0.00	0.27
Carbon Monoxide	CO	0.02	28.01	0.00	0.02	1	0.01	0.43
Hydrogen	H_2	2.63	2.02	1.30	28.77	0	0.58	0.00
Methane	CH_4	4.56	16.04	0.28	6.29	1	1.01	0.75
Acetylene	C_2H_2	0.07	26.04	0.00	0.06	2	0.02	0.92
Ethylene	C_2H_4	45.94	28.05	1.64	36.21	2	10.16	0.86
Ethane	C_2H_6	19.88	30.07	0.66	14.62	2	4.40	0.80
Methyl Acetylene	C_3H_4	0.14	40.07	0.00	0.08	3	0.03	0.90
Propadiene	C_3H_5	0.15	40.07	0.00	0.08	3	0.03	0.90
Proylene	C_3H_8	14.38	42.08	0.34	7.55	3	3.18	0.86
Propane	C_3H_8	10.90	44.10	0.25	5.46	3	2.41	0.82
Vinyl Acetylene	C_4H_4	0.01	52.08	0.00	0.00	4	0.00	0.92
1,3-Butadiene	C_4H_6	0.25	54.09	0.00	0.10	4	0.06	0.89
1-Butene	C_4H_8	0.04	56.11	0.00	0.02	4	0.01	0.86
Iso-Butane	C_4H_{10}	0.00	58.12	0.00	0.00	4	0.00	0.83
n-Butane	C_4H_{10}	0.06	58.12	0.00	0.02	4	0.01	0.83
1-Pentene	C_5H_{12}	0.18	67.10	0.00	0.06	5	0.04	0.89
Benzene	C_6H_6	0.25	78.12	0.00	0.07	6	0.05	0.92
Toluene	C_7H_8	0.02	92.14	0.00	0.00	7	0.00	0.91
Styrene	C_8H_8	0.01	104.15	0.00	0.00	8	0.00	0.92
Ethyl Benzene	C_8H_{10}	0.00	106.17	0.00	0.00	8	0.00	0.90
M-Xylene	C_8H_{10}	0.00	106.17	0.00	0.00	8	0.00	0.90
C6 Nonaro	C6 Nonaro	0.02	81.79	0.00	0.01	6	0.00	0.88
C7 Nonaro	C7 Nonaro	0.01	94.54	0.00	0.00	7	0.00	0.89
C8 Nonaro	C8 Nonaro	0.00	110.20	0.00	0.00	8	0.00	0.87
C9 Aro	C9 Aro	0.00	118.19	0.00	0.00	9	0.00	0.91
C9 Nonaro	C9 Nonaro	0.00	127.29	0.00	0.00	9	0.00	0.85
C10s	C10s	0.01	128.58	0.00	0.00	10	0.00	0.93
C11s+	C11s+	0.00	249.58	0.00	0.00	11	0.00	0.53
		100.0		4.5	100.0			

MW Carbon	12.01	lb/lbmol

Average MW of Shutdown Stream #3 = 22.1

Average Carbon Content of Shutdown Stream #3 = 0.81

Shutdown Stream #4

Component		Wt %	Component MW (lb/lbmol)	Moles	Mol %	Atoms Carbon	Stream MW (lb/lbmol)	Carbon Content (lb/lb fuel)
Nitrogen	N_2	73.67	28.00	2.63	63.20	0	17.70	0.00
Carbon Dioxide	CO_2	1.10	44.01	0.02	0.60	1	0.26	0.27
Methane	CH_4	23.30	16.04	1.45	34.89	1	5.60	0.75
Ethane	C_2H_6	1.20	30.07	0.04	0.96	2	0.29	0.80
Propane	C_3H_8	0.40	44.09	0.01	0.22	3	0.10	0.82
Pentane	C_5H_{12}	0.14	72.15	0.00	0.05	5	0.03	0.83
Butane	C_4H_{10}	0.19	58.12	0.00	0.08	4	0.05	0.83
		100.0		4.2	100.0			

MW Carbon	12.01	lb/lbmol

Average MW of Shutdown Stream #4 = 24.0
Average Carbon Content of Shutdown Stream #4 = 0.19

Maintenance Stream #5

Component		Wt %	Component MW (lb/lbmol)	Moles	Mol %	Atoms Carbon	Stream MW (lb/lbmol)	Carbon Content (lb/lb fuel)
Hydrogen Sulfide	H_2S	0.00	34.08	0.00	0.00	0	0.00	0.00
Water	H_2O	0.00	18.02	0.00	0.00	0	0.00	0.00
Carbon Dioxide	CO_2	0.01	44.01	0.00	0.01	1	0.00	0.27
Carbon Monoxide	CO	0.00	28.01	0.00	0.00	1	0.00	0.43
Hydrogen	H_2	0.00	2.02	0.00	0.00	0	0.00	0.00
Methane	CH_4	0.01	16.04	0.00	0.03	1	0.00	0.75
Acetylene	C_2H_2	0.00	26.04	0.00	0.00	2	0.00	0.92
Ethylene	C_2H_4	99.93	28.05	3.56	99.92	2	28.03	0.86
Ethane	C_2H_6	0.05	30.07	0.00	0.05	2	0.01	0.80
Methyl Acetylene	C_3H_4	0.00	40.07	0.00	0.00	3	0.00	0.90
Propadiene	C_3H_5	0.00	40.07	0.00	0.00	3	0.00	0.90
Propylene	C_3H_8	0.00	42.08	0.00	0.00	3	0.00	0.86
Propane	C_3H_8	0.00	44.10	0.00	0.00	3	0.00	0.82
Vinyl Acetylene	C_4H_4	0.00	0.00	0.00	0.00	4	0.00	0.00
1,3-Butadiene	C_4H_6	0.00	54.09	0.00	0.00	4	0.00	0.89
1-Butene	C_4H_8	0.00	56.11	0.00	0.00	4	0.00	0.86
iso-Butane	C_4H_{10}	0.00	58.12	0.00	0.00	4	0.00	0.83
n-Butane	C_4H_{10}	0.00	58.12	0.00	0.00	4	0.00	0.83
C5's(1-Pentene)	C_5H_{12}	0.00	67.10	0.00	0.00	5	0.00	0.89
Benzene	C_6H_6	0.00	78.12	0.00	0.00	6	0.00	0.92
Toluene	C_7H_8	0.00	92.14	0.00	0.00	7	0.00	0.91
M-Xylene	C_8H_{10}	0.00	106.17	0.00	0.00	8	0.00	0.90
Styrene	C_8H_8	0.00	104.15	0.00	0.00	8	0.00	0.92
Ethylbenzene	C_8H_{10}	0.00	106.17	0.00	0.00	8	0.00	0.90
C6 Nonaro	C6 Nonaro	0.00	81.79	0.00	0.00	6	0.00	0.88
C7 Nonaro	C7 Nonaro	0.00	94.54	0.00	0.00	7	0.00	0.89
C8 Nonaro	C8 Nonaro	0.00	110.20	0.00	0.00	8	0.00	0.87
C9 Aro	C9 Aro	0.00	118.19	0.00	0.00	9	0.00	0.91
C9 Nonaro	C9 Nonaro	0.00	127.29	0.00	0.00	9	0.00	0.85
C10s	C10s	0.00	128.58	0.00	0.00	10	0.00	0.93
C11+ (Fuel Oil)	C11+ (Fuel Oil)	0.00	249.58	0.00	0.00	11	0.00	0.53
		100.0		3.6	100.0			

MW Carbon	12.01	lb/lbmol

Average MW of Maintenance Stream #5 = 28.1
Average Carbon Content of Maintenance Stream #5 = 0.86

Maintenance Stream #6

Component		Wt %	Component MW (lb/lbmol)	Moles	Mol %	Atoms Carbon	Stream MW (lb/lbmol)	Carbon Content (lb/lb fuel)
Hydrogen Sulfide	H_2S	0.00	34.08	0.00	0.00	0	0.00	0.00
Water	H_2O	0.00	18.02	0.00	0.00	0	0.00	0.00
Carbon Dioxide	CO_2	0.00	44.01	0.00	0.00	1	0.00	0.27
Carbon Monoxide	CO	0.00	28.01	0.00	0.00	1	0.00	0.43
Hydrogen	H_2	0.00	2.02	0.00	0.00	0	0.00	0.00
Methane	CH_4	0.00	16.04	0.00	0.00	1	0.00	0.75
Acetylene	C_2H_2	0.00	26.04	0.00	0.00	2	0.00	0.92
Ethylene	C_2H_4	0.00	28.05	0.00	0.00	2	0.00	0.86
Ethane	C_2H_6	0.06	30.07	0.00	0.08	2	0.02	0.80
Methyl Acetylene	C_3H_4	0.53	40.07	0.01	0.57	3	0.23	0.90
Propadiene	C_3H_5	0.69	40.07	0.02	0.73	3	0.29	0.90
Propylene	C_3H_8	80.85	42.08	1.92	81.45	3	34.27	0.86
Propane	C_3H_8	17.85	44.10	0.40	17.16	3	7.57	0.82
Vinyl Acetylene	C_4H_4	0.00	0.00	0.00	0.00	4	0.00	0.00
1,3-Butadiene	C_4H_6	0.01	54.09	0.00	0.01	4	0.01	0.89
1-Butene	C_4H_8	0.00	56.11	0.00	0.00	4	0.00	0.86
iso-Butane	C_4H_{10}	0.00	58.12	0.00	0.00	4	0.00	0.83
n-Butane	C_4H_{10}	0.00	58.12	0.00	0.00	4	0.00	0.83
C5's(1-Pentene)	C_5H_{12}	0.00	67.10	0.00	0.00	5	0.00	0.89
Benzene	C_6H_6	0.00	78.12	0.00	0.00	6	0.00	0.92
Toluene	C_7H_8	0.00	92.14	0.00	0.00	7	0.00	0.91
M-Xylene	C_8H_{10}	0.00	106.17	0.00	0.00	8	0.00	0.90
Styrene	C_8H_8	0.00	104.15	0.00	0.00	8	0.00	0.92
Ethylbenzene	C_8H_{10}	0.00	106.17	0.00	0.00	8	0.00	0.90
C6 Nonaro	C6 Nonaro	0.00	81.79	0.00	0.00	6	0.00	0.88
C7 Nonaro	C7 Nonaro	0.00	94.54	0.00	0.00	7	0.00	0.89
C8 Nonaro	C8 Nonaro	0.00	110.20	0.00	0.00	8	0.00	0.87
C9 Aro	C9 Aro	0.00	118.19	0.00	0.00	9	0.00	0.91
C9 Nonaro	C9 Nonaro	0.00	127.29	0.00	0.00	9	0.00	0.85
C10s	C10s	0.00	128.58	0.00	0.00	10	0.00	0.93
C11+ (Fuel Oil)	C11+ (Fuel Oil)	0.00	249.58	0.00	0.00	11	0.00	0.53
		100.0		2.4	100.0			

MW Carbon	12.01	lb/lbmol

Average MW of Maintenance Stream #6 = 42.4

Average Carbon Content of Maintenance Stream #6 = 0.85

TOX/LP Flare Waste Gas (Routine Vents)

Component		Avg Wt %	Component MW (lb/lbmol)	Moles	Mol %	Atoms Carbon	Stream MW (lb/lbmol)	Carbon Content (lb/lb fuel)
Hydrogen	H_2	0.01	2.02	0.00	0.13	0	0.00	0.00
Nitrogen	N_2	93.81	28.01	3.35	92.87	0	26.01	0.00
Carbonmonoxide	CO	0.07	28.01	0.00	0.07	1	0.02	0.43
Methane	CH_4	0.30	16.04	0.02	0.52	1	0.08	0.75
Ethylene	C_2H_4	0.27	28.05	0.01	0.26	2	0.07	0.86
Ethane	C_2H_6	0.11	30.07	0.00	0.10	2	0.03	0.80
Carbon Dioxide	CO_2	0.07	44.01	0.00	0.04	1	0.02	0.27
Acetylene	C_2H_2	0.00	26.04	0.00	0.00	2	0.00	0.92
Hydrogen Sulfide	H_2S	0.00	34.08	0.00	0.00	0	0.00	0.00
Cyclopropane	C_3H_6	0.00	42.08	0.00	0.00	3	0.00	0.86
Propane	C_3H_8	0.00	44.10	0.00	0.00	3	0.00	0.82
Isobutane	C_4H_{10}	0.00	58.12	0.00	0.00	4	0.00	0.83
Sulfur Dioxide	SO_2	0.00	64.06	0.00	0.00	0	0.00	0.00
Iso Butene	C_4H_8	0.00	56.11	0.00	0.00	4	0.00	0.86
n- Butene	C_4H_8	0.00	56.11	0.00	0.00	4	0.00	0.86
1,3 -Butadiene	C_4H_6	0.01	54.09	0.00	0.00	4	0.00	0.89
Butane	C_4H_{10}	0.00	58.12	0.00	0.00	4	0.00	0.83
IsoPentane	C_5H_{12}	0.00	72.15	0.00	0.00	5	0.00	0.83
N Pentene	C_5H_{10}	0.00	70.13	0.00	0.00	5	0.00	0.86
n-Pentane	C_5H_{12}	0.00	72.15	0.00	0.00	5	0.00	0.83
Methyl CycloPentane	C_6H_{12}	0.00	84.16	0.00	0.00	6	0.00	0.86
Benzene	C_6H_6	0.04	78.11	0.00	0.01	6	0.01	0.92
Water	H_2O	1.15	18.02	0.06	1.76	0	0.32	0.00
Toluene	C_7H_8	0.00	92.14	0.00	0.00	7	0.00	0.91
Isoproprycyclohexane	C_9H_{18}	0.00	126.24	0.00	0.00	9	0.00	0.86
Xylene	C_8H_{10}	0.00	106.16	0.00	0.00	8	0.00	0.91
Styrene	C_8H_8	0.00	104.15	0.00	0.00	8	0.00	0.92
3,3,5-Trimethylheptane	$C_{10}H_{22}$	0.00	142.32	0.00	0.00	10	0.00	0.84
Ethyltol	C_9H_{12}	0.00	120.19	0.00	0.00	9	0.00	0.90
Methanol	CH_4O	0.00	32.04	0.00	0.00	1	0.00	0.37
Oxygen	O_2	3.24	32.00	0.10	2.80	0	0.90	0.00
Argon	Ar	0.91	18.00	0.05	1.40	0	0.25	0.00
Ammonia	NH_3	0.00	17.03	0.00	0.00	0	0.00	0.00
		100.00		3.6	100.0			

MW Carbon	12.01	lb/lbmol

Average MW of TOX/LP Flare Waste Gas = 27.7
Average Carbon Content of TOX/LP Flare Waste Gas = 0.01

Ground Flare Waste Gas (Routine Vents)

Component		Wt %	Component MW (lb/lbmol)	Moles	Mol %	Atoms Carbon	Stream MW (lb/lbmol)	Carbon Content (lb/lb fuel)
Hyrdrogen	H_2	0.84	2.02	0.41	7.97	0	0.16	0.00
Nitrogen	N_2	20.13	28.01	0.72	13.84	0	3.88	0.00
Carbon Monoxide	CO	0.00	28.01	0.00	0.00	1	0.00	0.43
Methane	CH_4	53.13	16.04	3.31	63.76	1	10.23	0.75
Ethylene	C_2H_4	9.77	28.05	0.35	6.70	2	1.88	0.86
Ethanol	C_2H_6	4.49	30.07	0.15	2.88	2	0.87	0.80
Carbon Dioxide	CO_2	2.10	44.01	0.05	0.92	1	0.40	0.27
Acetylene	C_2H_2	0.00	26.04	0.00	0.00	2	0.00	0.92
Hydrogen Sulfide	H_2S	0.00	34.08	0.00	0.00	0	0.00	0.00
Propylene	C_3H_6	2.34	42.08	0.06	1.07	3	0.45	0.86
Propane	C_3H_8	1.41	44.10	0.03	0.62	3	0.27	0.82
Isobutane	C_4H_{10}	0.06	58.12	0.00	0.02	4	0.01	0.83
Isobutene	C_4H_8	0.17	56.11	0.00	0.06	4	0.03	0.86
N-Butene	C_4H_8	0.23	56.11	0.00	0.08	4	0.04	0.86
1,3-Butadiene	C_4H_6	0.88	54.09	0.02	0.31	4	0.17	0.89
N-Butane	C_4H_{10}	0.32	58.12	0.01	0.11	4	0.06	0.83
Isopentane	C_5H_{12}	0.00	72.15	0.00	0.00	5	0.00	0.83
N-Pentene	C_5H_{10}	1.27	70.13	0.02	0.35	5	0.24	0.86
Normal Pentane	C_5H_{12}	0.00	72.15	0.00	0.00	5	0.00	0.83
Methanol	CH_4O	1.27	32.04	0.04	0.76	1	0.24	0.37
Methyl -Cyclopentane	C_6H_{12}	0.57	84.16	0.01	0.13	6	0.11	0.86
Benzene	C_6H_6	0.00	78.11	0.00	0.00	6	0.00	0.92
Water	H_2O	0.26	18.02	0.01	0.27	0	0.05	0.00
Dimethyl Disulfide	$C_2H_6S_2$	0.76	94.20	0.01	0.16	2	0.15	0.25
		100.00		5.2	100.0			

MW Carbon	12.01	lb/lbmol

Average MW of Ground Flare Waste Gas = 19.2

Average Carbon Content of Ground Flare Waste Gas = 0.59

Example Calculation (Carbon Dioxide Component):

Carbon Content = (Component MW (lb/lbmol) * Atoms Carbon) / MW Carbon (lb/lbmol)

Carbon Content = (126.24 (lb/lbmol) * 9 (Atoms C)) / 12.01 (lb/lbmol)

Carbon Content = 0.86

FIN: OC2L9FU2
EPN: OC2FU2
LHC9 Process Area Fugitives

Fugitive Counts and Emission Summary

Stream	Valves		Hourly Emissions From Valves (lb/hr)	Flanges		Hourly Emissions From Flanges (lb/hr)	Screwed Connections		Hourly Emissions From Screwed Connections (lb/hr)	Compressors[2]	Hourly Emissions From Compressors (lb/hr)	Pumps[2]	Hourly Emissions From Pumps (lb/hr)	Relief Valves [2]	Hourly Emissions From Relief Valves (lb/hr)	Bull Plugs[3]		Hourly Emissions From Bull Plugs (lb/hr)	% Valves/ Flanges Monitored	Hourly Emissions (lb/hr)	Annual Emissions (TPY)
	Gas	LL		Gas	LL		Gas	LL		Gas		LL				Gas	LL				
SOCMI w/ C2 Factor (lb/hr)	0.0258	0.0459		0.0053	0.0052		0.0053	0.0052		0.5027		0.144		0.2293		0.0075	0.0075				
SOCMI Average Factor (lb/hr)	0.0132	0.0089		0.0039	0.0005		0.0039	0.0005		0.5027		0.0439		0.2293		0.0038	0.0038				
SOCMI w/o C2 Factor (lb/hr)	0.0089	0.0035		0.0029	0.0005		0.0029	0.0005		0.5027		0.0386		0.2293		0.004	0.004				
28VHP Control Eff. (%)	97%	97%		97%	97%		97%	97%		100%		100%		100%		100%	100%				
10401	-	102	0.014	-	168	0.003	-	8	0.0001	-	-	2	-	5	-	-	46	-	99.0	0.018	0.08
11501	-	101	0.014	-	169	0.003	-	14	0.0002	-	-	-	-	4	-	-	37	-	99.0	0.018	0.08
17502	-	88	0.012	-	181	0.004	-	4	0.0001	-	-	-	-	1	-	-	23	-	99.0	0.016	0.07
22501	-	19	0.003	-	30	0.001	-	4	0.0001	-	-	-	-	-	-	-	7	-	99.0	0.003	0.01
23501	-	17	0.002	-	33	0.001	-	-	-	-	-	-	-	-	-	-	5	-	99.0	0.003	0.01
27301	-	21	0.007	-	40	0.001	-	-	-	-	-	-	-	-	-	-	7	-	99.0	0.008	0.04
28001	-	55	0.008	-	90	0.002	-	8	0.0001	-	-	-	-	-	-	-	17	-	99.0	0.010	0.04
30102	-	70	0.010	-	117	0.002	-	3	0.00005	-	-	1	-	3	-	-	28	-	99.0	0.012	0.05
30103	-	68	0.009	-	123	0.002	-	9	0.0001	-	-	-	-	6	-	-	24	-	99.0	0.012	0.05
30705	-	22	0.008	-	45	0.001	-	-	-	-	-	-	-	-	-	-	6	-	99.0	0.009	0.04
33002	-	24	0.008	-	40	0.001	-	4	0.0001	-	-	-	-	-	-	-	8	-	99.0	0.009	0.04
33103	-	12	0.004	-	32	0.001	-	3	0.00005	-	-	-	-	-	-	-	2	-	99.0	0.005	0.02
34002	-	31	0.011	-	48	0.001	-	9	0.0001	-	-	-	-	-	-	-	7	-	99.0	0.012	0.05
34202	-	20	0.007	-	34	0.001	-	9	0.0001	-	-	-	-	-	-	-	2	-	99.0	0.008	0.03
34402	-	19	0.007	-	30	0.001	-	4	0.0001	-	-	-	-	-	-	-	7	-	99.0	0.007	0.03
34702	-	14	0.002	-	22	0.0004	-	1	0.00002	-	-	-	-	-	-	-	5	-	99.0	0.002	0.01
34903	-	16	0.002	-	31	0.001	-	4	0.0001	-	-	-	-	-	-	-	4	-	99.0	0.003	0.01
35601	-	96	0.013	-	171	0.003	-	12	0.0002	-	-	2	-	-	-	-	36	-	99.0	0.017	0.07
42104	-	123	0.017	-	230	0.005	-	9	0.0001	-	-	-	-	8	-	-	46	-	99.0	0.022	0.10
42401	-	86	0.012	-	146	0.003	-	4	0.0001	-	-	4	-	-	-	-	39	-	99.0	0.015	0.07
42902	-	9	0.001	-	19	0.0004	-	-	-	-	-	-	-	-	-	-	2	-	99.0	0.002	0.01
42904	-	9	0.001	-	17	0.0003	-	-	-	-	-	-	-	-	-	-	2	-	99.0	0.002	0.01
43401	-	136	0.019	-	224	0.004	-	5	0.0001	-	-	4	-	2	-	-	56	-	99.0	0.023	0.10
43601	-	247	0.034	-	439	0.009	-	12	0.0002	-	-	4	-	6	-	-	90	-	99.0	0.043	0.19
43605	-	127	0.018	-	244	0.005	-	9	0.0001	-	-	-	-	3	-	-	37	-	99.0	0.023	0.10
43606	-	55	0.008	-	98	0.002	-	2	0.00003	-	-	-	-	4	-	-	21	-	99.0	0.010	0.04
5913	-	6	0.001	-	10	0.0002	-	-	-	-	-	-	-	1	-	-	3	-	99.0	0.001	0.00
61400	-	206	0.029	-	377	0.007	-	9	0.0001	-	-	-	-	8	-	-	71	-	99.0	0.036	0.16
66101	-	222	0.405	-	391	0.081	-	24	0.0037	-	-	2	-	2	-	-	83	-	99.0	0.489	2.14
Acid	-	98	0.014	-	208	0.004	-	13	0.0002	-	-	1	-	1	-	-	28	-	99.0	0.018	0.08
Methanol	-	120	0.017	-	205	0.004	-	12	0.0002	-	-	1	-	5	-	-	53	-	99.0	0.021	0.09
Spent Caustic	-	939	0.130	-	1,760	0.035	-	122	0.0018	-	-	20	-	13	-	-	353	-	99.0	0.167	0.73
Wash Oil	-	274	0.038	-	442	0.009	-	13	0.0002	-	-	4	-	2	-	-	138	-	99.0	0.047	0.21
Flare Liquids	-	169	0.023	-	278	0.006	-	6	0.0001	-	-	7	-	2	-	-	71	-	99.0	0.029	0.13
61100 Liquids	-	33	0.005	-	66	0.001	-	4	0.0001	-	-	1	-	-	-	-	10	-	99.0	0.006	0.03
6401	85	-	0.030	140	-	0.016	9	-	0.0008	-	-	-	-	-	-	25	-	-	99.0	0.047	0.21
10001	1,008	-	0.356	1,223	-	0.141	644	-	0.0560	-	-	-	-	-	-	541	-	-	99.0	0.553	2.42
10003	13	-	0.005	22	-	0.003	4	-	0.0003	-	-	-	-	-	-	5	-	-	99.0	0.007	0.03
10402	2	-	0.001	4	-	0.0005	-	-	-	-	-	-	-	-	-	1	-	-	99.0	0.001	0.01
11601	72	-	0.025	120	-	0.014	6	-	0.0005	-	-	-	-	2	-	28	-	-	99.0	0.040	0.17
11602	120	-	0.042	80	-	0.009	-	-	-	-	-	-	-	-	-	96	-	-	99.0	0.052	0.23
15110	380	-	0.199	730	-	0.113	52	-	0.0061	2	-	-	-	15	-	134	-	-	99.0	0.318	1.39
20010	22	-	0.023	41	-	0.009	4	-	0.0006	-	-	-	-	-	-	6	-	-	99.0	0.032	0.14

FIN: OC2L9FU2
EPN: OC2FU2
LHC9 Process Area Fugitives

Fugitive Counts and Emission Summary

Stream	Valves		Hourly Emissions From Valves (lb/hr)	Flanges		Hourly Emissions From Flanges (lb/hr)	Screwed Connections		Hourly Emissions From Screwed Connections (lb/hr)	Compressors[2]	Hourly Emissions From Compressors (lb/hr)	Pumps[2]	Hourly Emissions From Pumps (lb/hr)	Relief Valves [2]	Hourly Emissions From Relief Valves (lb/hr)	Bull Plugs[3]		Hourly Emissions From Bull Plugs (lb/hr)	% Valves/ Flanges Monitored	Hourly Emissions (lb/hr)	Annual Emissions (TPY)
	Gas	LL		Gas	LL		Gas	LL		Gas		LL				Gas	LL				
SOCMI w/ C2 Factor (lb/hr)	0.0258	0.0459		0.0053	0.0052		0.0053	0.0052		0.5027		0.144		0.2293		0.0075	0.0075				
SOCMI Average Factor (lb/hr)	0.0132	0.0089		0.0039	0.0005		0.0039	0.0005		0.5027		0.0439		0.2293		0.0038	0.0038				
SOCMI w/o C2 Factor (lb/hr)	0.0089	0.0035		0.0029	0.0005		0.0029	0.0005		0.5027		0.0386		0.2293		0.004	0.004				
28VHP Control Eff. (%)	97%	97%		97%	97%		97%	97%		100%		100%		100%		100%	100%				
26100	278	-	0.146	518	-	0.080	24	-	0.0028	-	-	-	-	18	-	94	-	-	99.0	0.229	1.00
26501	31	-	0.011	68	-	0.008	1	-	0.0001	-	-	-	-	-	-	9	-	-	99.0	0.019	0.08
30101	21	-	0.011	35	-	0.005	2	-	0.0002	-	-	-	-	3	-	10	-	-	99.0	0.017	0.07
30104	137	-	0.072	256	-	0.040	26	-	0.0030	1	-	-	-	5	-	46	-	-	99.0	0.114	0.50
30701	54	-	0.028	101	-	0.016	8	-	0.0009	-	-	-	-	2	-	20	-	-	99.0	0.045	0.20
32500	3	-	0.001	10	-	0.001	1	-	0.0001	-	-	-	-	-	-	1	-	-	99.0	0.002	0.01
32702	24	-	0.013	37	-	0.006	5	-	0.0006	-	-	-	-	2	-	9	-	-	99.0	0.019	0.08
33106	99	-	0.052	170	-	0.026	14	-	0.0016	-	-	-	-	-	-	31	-	-	99.0	0.080	0.35
33001	12	-	0.006	31	-	0.005	1	-	0.0001	-	-	-	-	2	-	7	-	-	99.0	0.011	0.05
33101	22	-	0.012	39	-	0.006	4	-	0.0005	-	-	-	-	2	-	8	-	-	99.0	0.018	0.08
34201	30	-	0.011	49	-	0.006	2	-	0.0002	-	-	-	-	2	-	12	-	-	99.0	0.016	0.07
34302	78	-	0.041	144	-	0.022	9	-	0.0011	2	-	-	-	2	-	29	-	-	99.0	0.064	0.28
34804	4	-	0.001	8	-	0.001	3	-	0.0003	-	-	-	-	-	-	4	-	-	99.0	0.003	0.01
34805	260	-	0.092	404	-	0.047	18	-	0.0016	-	-	-	-	5	-	113	-	-	99.0	0.140	0.61
34901	35	-	0.012	68	-	0.008	2	-	0.0002	-	-	-	-	2	-	13	-	-	99.0	0.020	0.09
34906	45	-	0.016	84	-	0.010	3	-	0.0003	-	-	-	-	2	-	18	-	-	99.0	0.026	0.11
40801	196	-	0.103	391	-	0.061	20	-	0.0023	-	-	-	-	5	-	50	-	-	99.0	0.166	0.73
42101	40	-	0.014	70	-	0.008	5	-	0.0004	-	-	-	-	2	-	16	-	-	99.0	0.023	0.10
42301	63	-	0.022	100	-	0.012	9	-	0.0008	-	-	-	-	2	-	23	-	-	99.0	0.035	0.15
42801	71	-	0.025	135	-	0.016	4	-	0.0003	-	-	-	-	1	-	24	-	-	99.0	0.041	0.18
43101	38	-	0.013	69	-	0.008	6	-	0.0005	-	-	-	-	3	-	18	-	-	99.0	0.022	0.10
50200	35	-	0.012	56	-	0.006	4	-	0.0003	-	-	-	-	2	-	17	-	-	99.0	0.019	0.08
50301	1,177	-	0.416	2,072	-	0.239	65	-	0.0057	-	-	-	-	10	-	311	-	-	99.0	0.660	2.89
61100	210	-	0.074	405	-	0.047	15	-	0.0013	1	-	-	-	10	-	72	-	-	99.0	0.122	0.53
61200	57	-	0.020	96	-	0.011	6	-	0.0005	-	-	-	-	2	-	20	-	-	99.0	0.032	0.14
66401	213	-	0.218	399	-	0.084	39	-	0.0062	1	-	-	-	11	-	72	-	-	99.0	0.308	1.35
Ammonia	166	-	0.059	311	-	0.036	15	-	0.0013	-	-	-	-	9	-	88	-	-	99.0	0.096	0.42
Analyzer Gas	-	-	-	15	-	0.002	-	-	-	-	-	-	-	-	-	-	-	-	99.0	0.002	0.01
Chlorine	18	-	0.006	41	-	0.005	2	-	0.0002	-	-	-	-	-	-	9	-	-	99.0	0.011	0.05
Flare	267	-	0.140	522	-	0.081	60	-	0.0070	-	-	-	-	-	-	111	-	-	99.0	0.228	1.00
LP Flare	76	-	0.027	133	-	0.015	11	-	0.0010	-	-	-	-	-	-	37	-	-	99.0	0.043	0.19
Totals	**5462**	**3654**		**9197**	**6558**		**1103**	**340**		**7**		**53**		**197**		**2128**	**1374**			**4.80**	**21.05**

Notes:
1) Fugitive emission count based on Dow review of preliminary P&IDs
2) Compressors and relief valves are routed to operating control device (flare), therefore 100% control claimed. Pumps utilize dual mechanical seals, therefore 100% control claimed.
3) Component actually represents an open ended line equipped with a plug. Since equipped with a plug, 100% control credit utilized.

Total Speciated Fugitive Emissions

Component	Hourly Emissions (lb/hr)	Annual Emissions (TPY)
Carbon Dioxide	0.005	0.02
Carbon Monoxide	0.02	0.10
Hydrogen	0.28	1.21
Methane	0.87	3.82
Water	0.17	0.73
Nitrogen	0.07	0.30
Ammonia	0.10	0.42
Hydrogen Chloride	0.02	0.08
Chlorine	0.01	0.05
Acetylene	0.003	0.01
Ethylene	1.46	6.38
Ethanol	1.03	4.50
Methyl Acetylene	0.002	0.01
Propadiene	0.002	0.01
Propylene	0.23	0.99
Propane	0.11	0.50
Butadiene	0.07	0.30
Butenes	0.01	0.06
Butanes	0.02	0.07
C5's	0.07	0.30
Benzene	0.13	0.56
C6 Nonarom	0.01	0.04
C7's	0.02	0.11
Styrene	0.02	0.08
C8 Arom	0.01	0.04
C8 Nonarom	0.003	0.01
C9's	0.01	0.05
C10's	0.01	0.05
DMDS	0.03	0.14
Methanol	0.02	0.09
Total	4.80	21.05
Total VOC	**3.27**	**14.30**

Sample Calculation:

Stream 10003 Valves:

Emission rate = (Total # Gas Valves) x (Emission Factor) x (% Monitored Valves/Flanges) x (100% - % Control Efficiency) + (Total # Gas Valves) x (Emission Factor) x (% Unmonitored Valves/Flanges)

lb./hr = (13 Gas Valves) x (0.0089, SOCMI w/o C2) x (99% Monitored Valves/Flanges) x (100% - 97% Control Efficiency, 28VHP) + (13 Gas Valves) x (0.0089, SOCMI w/o C2) x (1.0% Unmonitored Valves/Flanges)

lb./hr = 0.005

TPY = (Emission Rate, lb/hr) x (8760 hr/yr) x (1 ton / 2000 lb)

TPY = 0.020

Speciated Sample Calculation (for Propane in the 10003 Stream):

Emission Rate for Propane (lb/hr) = (wt% Propane in 10003 Stream) x (10003 Stream Emissions lb/hr)

= (0.33) * (0.007)

lb/hr = 0.002

Emission Rate for Propane (tpy) = (0.002 lb/hr) x (8760 hr/yr) / (2000 lb/ton)

tpy = 0.01

Please note sample calculation is for one stream only. Total emissions table shown above includes all streams.

Appendix C

TCEQ LDAR Sample Special Conditions: 28 VHP

Texas Commission on Environmental Quality
Air Permits Division

New Source Review (NSR) Boilerplate Special Conditions

This information is maintained by the Chemical NSR Section and is subject to change. Last update was made **August 2011**. These special conditions represent current NSR boilerplate guidelines and are provided for informational purposes only. The special conditions for any permit or amendment are subject to change through TCEQ case-by-case evaluation procedures [30 TAC 116.111(a)]. Please contact the appropriate Chemical NSR Section management if there are questions related to the boilerplate guidelines.

<u>Piping, Valves, Connectors, Pumps, and Compressors in Volatile Organic Compounds (VOC) Service - 28VHP</u>

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 pounds per square inch, absolute (psia) at 68 degrees Fahrenheit or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list or by one of the methods described below to be made available upon request.

   The exempted components may be identified by one or more of the following methods:

   i. piping and instrumentation diagram (PID); or
   ii. a written or electronic database.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), shall be identified in a list to be made available upon request. The non-accessible valves may be identified by one or more of the methods described in subparagraph A above.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 8 hours of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed. If the removal of a component for repair or replacement results in an open-ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 24 hours. If the repair or replacement is not completed within 24 hours, the line or valve must have a cap, blind flange, plug, or second valve installed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in Method 21 of 40 CFR part 60, appendix A. The gas analyzer shall be calibrated with methane. In addition, the response factor of the instrument for a specific VOC of interest shall be determined and meet the requirements of Section 8 of Method 21. If a mixture of VOCs are being monitored, the response factor shall be calculated for the average composition of the process fluid. If a response factor less than 10 cannot be achieved using methane, than the instrument may be calibrated with one of the VOC to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each of the VOC to be measured.

Replacements for leaking components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump, compressor, and agitator seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 parts per million by volume (ppmv) or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump, compressor, and agitator seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired.

I. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC 115.782 (c)(1)(B)(i)(II). When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shutdown, the TCEQ Executive Director or designated representative shall be notified and may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown.

J. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections shall be noted in the operator's log or equivalent.

K. Alternative monitoring frequency schedules of 30 TAC §§ 115.352 - 115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR Part 63, Subpart H, may be used in lieu of Items F through G of this condition.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard (NSPS), or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS) and does not constitute approval of alternative standards for these regulations.

Control Efficiencies for TCEQ Leak Detection and Repair Programs

Equipment/Service	28M	28RCT	28VHP	28MID	28LAER	Audio/Visual /Olfactory[1]
Valves						
Gas/Vapor	75%	97%	97%	97%	97%	97%
Light Liquid	75%	97%	97%	97%	97%	97%
Heavy Liquid[2]	0%[3]	0%[4]	0%[4]	0%[4]	0%[4]	97%
Pumps						
Light Liquid	75%	75%	85%	93%	93%	93%
Heavy Liquid[2]	0%[3]	0%[3]	0%[5]	0%[6]	0%[6]	93%
Flanges/Connectors						
Gas/Vapor[7]	30%	30%	30%	30%	97%	97%
Light Liquid[7]	30%	30%	30%	30%	97%	97%
Heavy Liquid	30%	30%	30%	30%	30%	97%
Compressors	75%	75%	85%	95%	95%	95%
Relief Valves (Gas/Vapor)	75%	97%	97%	97%	97%	97%
Open-ended Lines[8]	75%	97%	97%	97%	97%	97%
Sampling Connections	75%	97%	97%	97%	97%	97%

Audio, visual, and olfactory walk-through inspections are applicable for inorganic/odorous and low vapor pressure compounds such as chlorine, ammonia, hydrogen sulfide, hydrogen fluoride, and hydrogen cyanide.

Monitoring components in heavy liquid service is not required by any of the 28 Series LDAR programs. If monitored with an instrument, the applicant must demonstrate that the VOC being monitored has sufficient vapor pressure to allow reduction.

No credit may be taken if the concentration at saturation is below the leak definition of the monitoring program (i.e. (0.044 psia/14.7 psia) x 106 = 2,993 ppmv versus leak definition = 10,000 ppmv).

Valves in heavy liquid service may be given a 97% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.

Pumps in heavy liquid service may be given an 85% reduction credit if monitored at 2,000 ppmv by permit condition provided that the concentration at saturation is greater than 2,000 ppmv.

Pumps in heavy liquid service may be given a 93% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.

If the applicant decides to monitor connectors using an organic vapor analyzer (OVA) at the same leak definition as valves, then the applicable valve reduction credit may be used instead of the 30% reduction credit. If this option is chosen, the applicant shall continue to perform the weekly physical inspections in addition to the quarterly OVA monitoring.

The 28 Series quarterly LDAR programs require open-ended lines to be equipped with an appropriately sized cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.

Appendix D

RACT / BACT / LAER Clearinghouse Search Results

RACT/BACT/LAER Clearinghouse Results for
Emergency Diesel Generators
Pollutant: CO_2, CH_4

RBLCID	FACILITY_NAME	CORPORATE_OR_COMPANY_NAME	FACILITY_STATE	PROCESS_NAME	PROCCESS_TYPE	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	PROCESS_NOTES"	POLLUTANT	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	EMISSION_LIMIT_1_AVG_TIME_CONDITION
*AK-0076	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	Combustion of Diesel by ICEs	17.11	ULSD	1750	kW	Diesel-fired generators	Carbon Dioxide	N	Good Combustion Practices and 40 CFR 60 Subpart IIII requirements	0		
*FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	Main Propulsion Engines	17.11	Diesel	0		Wärtsilä Vasa 18V32 LNE and Wärtsilä Vasa 12V32 LNE model engines	Carbon Dioxide	P	Use of good combustion practices based on the current manufacturer?s specifications for these engines, and additional enhanced work practice standards including an engine performance management system and the Diesel Engines with Turbochargers (DEWT) measurement system.	700	G/KW-H	24-HOUR ROLLING
*FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	Crane Engines (units 1 and 2)	17.11	Diesel	0		Caterpillar 3408 - 1997 model year engines	Carbon Dioxide	P	Use of certified EPA Tier 1 engines and good combustion practices based on the current manufacturer?s specifications for this engine.	722	TONS PER YEAR	12-MONTH ROLLING
*FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	Crane Engines (units 3 and 4)	17.11	Diesel	0		Caterpillar 3406 - 2008 model year engines	Carbon Dioxide	N	Use of good combustion practices, based on the current manufacturer?s specifications for this engine	687	TONS PER YEAR	12-MONTH ROLLING
*FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	Emergency Engine	17.11	Diesel	0		MAN D-2842 LE model engine	Carbon Dioxide	N	Use of good combustion practices, based on the current manufacturer?s specifications for this engine	14.6	TONS PER YEAR	12-MONTH ROLLING
*FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	Emergency Fire Pump Engine	17.11	Diesel	0		Detroit 8V-92 TA model engine	Carbon Dioxide	N	Use of good combustion practices, based on the current manufacturer?s specifications for this engine	2.4	TONS PER YEAR	12-MONTH ROLLING
*IA-0105	IOWA FERTILIZER COMPANY		IA	Emergency Generator	17.11	diesel fuel	142	gal/hr	rated @ 2,000 KW	Carbon Dioxide	P	good combustion practices	1.55	G/KW-HR	AVERAGE OF 3 STACK TEST RUNS
*IA-0105	IOWA FERTILIZER COMPANY		IA	Fire Pump	17.21	diesel fuel	14	gal/hr	rated @ 235 KW	Carbon Dioxide	P	good combustion practices	1.55	G/KW-HR	AVERAGE OF 3 STACK TEST RUNS
*IA-0105	IOWA FERTILIZER COMPANY		IA	Emergency Generator	17.11	diesel fuel	142	gal/hr	rated @ 2,000 KW	Carbon Dioxide Equivalent (CO2e)	P	good combustion practices	788.5	TONS/YR	ROLLING 12 MONTH TOTAL
*IA-0105	IOWA FERTILIZER COMPANY		IA	Fire Pump	17.21	diesel fuel	14	gal/hr	rated @ 235 KW	Carbon Dioxide Equivalent (CO2e)	P	good combustion practices	91	TONS/YR	ROLLING 12 MONTH TOTAL
*IA-0105	IOWA FERTILIZER COMPANY		IA	Emergency Generator	17.11	diesel fuel	142	gal/hr	rated @ 2,000 KW	Methane	P	good combustion practices	0.0001	G/KW-HR	AVERAGE OF 3 STACK TEST RUNS
*IA-0105	IOWA FERTILIZER COMPANY		IA	Fire Pump	17.21	diesel fuel	14	gal/hr	rated @ 235 KW	Methane	P	good combustion practices	0.0001	G/KW-HR	AVERAGE OF 3 STACK TEST RUNS
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	EMERGENCY DIESEL GENERATOR	17.11	DIESEL	1250	HP		Carbon Dioxide	P	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	163	LB/MMBTU	
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	EMERGENCY FIRE PUMP	17.21	DIESEL	350	HP		Carbon Dioxide	P	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	163	LB/MMBTU	
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	EMERGENCY DIESEL GENERATOR	17.11	DIESEL	1250	HP		Methane	P	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0061	LB/MMBTU	
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	EMERGENCY FIRE PUMP	17.21	DIESEL	350	HP		Methane	P	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0061	LB/MMBTU	

RBLCID	FACILITY_NAME	FACILITY_STATE	PROCESS_NAME	PROCCESS_TYPE	PRIMARY_FUEL	THROUGH-PUT	THROUGHPUT_UNIT	POLLUTANT	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	EMISSION_LIMIT_1_AVG_TIME_CONDITION	PROCESS_NOTES"
CA-1145	BREITBURN ENERGY - NEWLOVE LEASE, ORCUTT HILL FIELD	CA	OIL AND GAS: FUGITIVE COMPONENTS	13.39	FIELD GAS	0		Volatile Organic Compounds (VOC)	A	LOW EMISSIONS DESIGN AND LOWER LDAR THRESHOLD (SEE BELOW)	100	PPMV	THC	EQUIP: LOW-EMISSION DESIGN VALVES, CONNECTIONS AND SEALS (SEE BELOW), MFR: VARIOUS, TYPE: VALVES, FLANGES, PUMP SEALS, COMPRESSOR SEALS, ETC, MODEL: VARIOUS, FUNC EQUIP: PIPING COMPONENTS IN OILFIELD OPERATIONS, FUEL_TYPE: , SCHEDULE: CONTINUOUS, H/D: 24, D/W: 7, W/Y: 365, NOTES: VALVES: BELLOWS, DIAPHRAGM SEAL, SPRING-LOADED PACKING, EXPANDABLE PACKING, GRAPHITE PACKING, PTE-COATED PACKING, PRECISION MACHINED STEM, SEALANT INJECTION AND LDAR: 100 PPMV THC. FLANGES/CONNECTORS/OTHER: WELDED, NEW GASKET RATED TO 150% OF PROCESS PRESSURE AT PROCESS TEMPERATURE. LDAR: 100 PPMV THC COMPRESSOR SEALS (ROTARY DRIVE): VENTED TO VAPOR RECOVERY OR CLOSED VENT, DUAL/TANDEM MECHANICAL SEALS, LEAKLESS DESIGN (E.G. MAGNETIC DRIVE). LDAR: 100 PPMV THC COMPRESSOR SEALS (RECIPROCATING DRIVE): VENTED TO VAPOR RECOVERY, ELASTOMER BELLOWS, O-RING SEALS, DRY RUNNING SECONDARY CONTAINMENT SEALS. LDAR: 100 PPMV THC PUMP SEALS: VENTED TO VAPOR RECOVERY OR CLOSED VENT, DUAL/TANDEM MECHANICAL SEALS. LDAR: 500 PPMV THC PRDS: VENTED TO VAPOR RECOVERY OR CLOSED VENT, SOFT-SEAT DESIGN. LDAR:
FL-0318	HIGHLANDS ETHANOL FACILITY	FL	Facility-wide Fugitive VOC Equipment Leaks	49.999		0		Volatile Organic Compounds (VOC)	P	The most practical method of controlling fugitive VOC emissions from HEF is to promptly repair any leaking components. HEF is subject to NSPS 40 CFR 60, Subpart VVa - VOC Equipment Leaks in the Synthetic Chemical Manufacturing Industry (SOCMI). NSPS Subpart VVa requires a LDAR program. HEF must come in to compliance with Subpart VVA, including the LDAR program, no later than 180 days after HEF becomes operational.	19.6	T/YR		Fugitive VOC emissions are grouped for the entire process and will be minimized by implementation of a monthly leak detection and repair (LDAR) monitoring program.
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	FL	Fugitive VOC Emission Leaks (facility-wide)	64.002		0		Volatile Organic Compounds (VOC)	P	The permittee shall demonstrate compliance with the requirements of §§60.482?1a through 60.482?10a or §60.480a(e) for all equipment subject to NSPS Subpart VVa within 180 days of initial startup of the SRF.	6.52	TON/YR		The fugitive VOC emissions from equipment leaks involved in the ethanol production process and associated processes at the SRF facility. Total fugitive VOC emissions from equipment leaks at the SRF facility were estimated to be 6.52 TPY. To minimize VOC fugitive emissions, SRF shall implement a monthly leak detection and repair (LDAR) program. The plan to implement the LDAR program shall be approved by the Compliance Authority in accordance with New Source Performance Standard (NSPS) 40 CFR Part 60, Subpart VVa.
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	FL	Fugitive Emissions - Equip Leaks	99.19		0		Volatile Organic Compounds (VOC)	P	The permittee shall demonstrate compliance with the requirements of §§60.482?1a through 60.482?10a or §60.480a(e) for all equipment subject to NSPS Subpart VVa within 180 days of initial startup of the ethanol facility.	6.52	T/YR	ESTIMATED EMISSIONS	This emission unit consists of the fugitive VOC emissions from equipment leaks involved in the ethanol production process and associated processes at the HEF facility. Total fugitive VOC emissions from equipment leaks at the HEF facility were estimated to be 6.52 TPY. Total HAP emissions from equipment leaks at the HEF facility were estimated to be 0.33 TPY. To minimize VOC fugitive emissions, HEF shall implement a monthly LDAR program. The plan to implement the LDAR program shall be approved by the Compliance Authority in accordance with NSPS 40 CFR Part 60, Subpart VVa.
IA-0082	GOLDEN GRAIN ENERGY	IA	FUGITIVE LEAKS	70.12				Volatile Organic Compounds (VOC)	P	LEAK DETECTION AND REPAIR ACCORDING TO NSPS SUBPART VV	8.75	T/YR		VOC LEAKS FROM EQUIPMENT
IL-0073	EXXONMOBIL OIL CORPORATION	IL	FUGITIVES	50.007				Volatile Organic Compounds (VOC)	N		3.76	T/YR		
LA-0125	WILLAMETTE INDUSTRIES, INC.	LA	FUGITIVE RESIN	30.39				Volatile Organic Compounds (VOC)	P	USING GLUE FORMULA WITH LOW VOC CONCENTRATION	6.22	LB/H		EIQ NO. 031
LA-0194	SABINE PASS LNG TERMINAL	LA	FUGITIVE EMISSIONS	99.999				Volatile Organic Compounds (VOC)	N	COMPLY WITH LAC 33:III.2111	0.25	LB/H	HOURLY MAXIMUM	FUGITIVE EMISSIONS FROM VALVES, CONNECTORS, ETC.
LA-0194	SABINE PASS LNG TERMINAL	LA	FUGITIVE EMISSIONS (ASSOCIATED W/ 528 AMBIENT AIR VAPORIZERS)	99.999				Volatile Organic Compounds (VOC)	N		0.25	LB/H	HOURLY MAXIMUM	
LA-0195	LAKE CHARLES FACILITY	LA	PROCESS FUGITIVES	63.039				Volatile Organic Compounds (VOC)	P	LDAR PROGRAM - 40 CFR 63 SUBPART I	18.3	LB/H	HOURLY MAXIMUM	
LA-0197	ALLIANCE REFINERY	LA	UNIT FUGITIVES	50.007				Volatile Organic Compounds (VOC)	P	LEAK DETECTION AND REPAIR PROGRAM - LOUISIANA REFINERY MACT DETERMINATION DATED JULY 26, 1994	13.22	LB/H	HOURLY MAXIMUM	NO THROUGHPUT, FUGITIVE EMISSIONS
LA-0208	IVANHOE CARBON BLACK PLANT	LA	HOT FEEDSTOCK OIL FUGITIVES	69.015				Volatile Organic Compounds (VOC)	N		0.41	LB/H	HOURLY MAXIMUM	VALVES, FLANGES, PUMPS, & AGITATORS
LA-0211	GARYVILLE REFINERY	LA	FUGITIVE EMISSIONS	50.007				Volatile Organic Compounds (VOC)	P	LDAR PROGRAM: COMPLY WITH OVERALL MOST STRINGENT PROGRAM APPLICABLE TO UNIT. APPLICABLE PROGRAMS INCLUDE 40 CFR 63 SUBPART CC, 40 CFR 60 SUBPART GGG, LAC 33:III.2121, & LAC 33:III.CHAPTER 51 (LA REFINERY MACT).	0		SEE NOTE	UNITS 9, 19, 20, 21, 25, 26, 32, 33, 34, 60, 205, 205A, 210, 211, 212, 212A, 214, 215, 220, 221, 222, 222A, 222B, 232, 233, 234, 241, 243, 247, 250, 250A, 259, 260, 263, 265, 267, & 271 INCLUDES EPN 10-00 & 16-00, AS WELL AS OTHERS.

RACT/BACT/LAER Clearinghouse Results for Piping Fugitives
Pollutant: CH4, VOC

RBLCID	FACILITY_NAME	FACILITY_STATE	PROCESS_NAME	PROCCESS TYPE	PRIMARY_FUEL	THROUGH-PUT	THROUGHPUT_UNIT	POLLUTANT	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	EMISSION_LIMIT_1_AVG_TIME_CONDITION	PROCESS_NOTES"
LA-0211	GARYVILLE REFINERY	LA	HYDROGEN PLANT FUGITIVES (51-08)	50.007				Volatile Organic Compounds (VOC)	P	LDAR PROGRAM: LAC 33:III.2121	0		SEE NOTE	
LA-0213	ST. CHARLES REFINERY	LA	FUGITIVE EMISSIONS	50.007				Volatile Organic Compounds (VOC)	P	REFINERY (90-0): LA REFINERY MACT LDAR PROGRAM; ARU (2008-39): MONITORING ACCORDING TO 40 CFR 63 SUBPART H; ARU LOADING (2008-37): MONITORING ACCORDING TO 40 CFR 61 SUBPART V	0		SEE NOTE	INCLUDING: ROAD DUST 90-0: REFINERY FUGITIVES 2008-39: ARU FUGITIVES 2008-37: ARU MARINE LOADING DOCK FUGITIVES
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	LA	FUGITIVE EMISSIONS	99.999				Volatile Organic Compounds (VOC)	N		0.62	LB/H	HOURLY MAXIMUM	
LA-0225	NORCO REFINERY	LA	HYDROCRACKER UNIT FUGITIVE EMISSIONS 3011-95	50.003	NONE			Volatile Organic Compounds (VOC)	N	¿40 CFR 60 SUBPART GGG ¿40 CFR 63 SUBPART CC ¿LOUISIANA MACT DETERMINATION FOR REFINERY EQUIPMENT LEAKS ¿ JULY 26, 1994	100.4	T/YR		
LA-0225	NORCO REFINERY	LA	DIESEL HYDROTREATER UNIT FUGITIVE EMISSIONS 5011-99	50.003				Volatile Organic Compounds (VOC)	N	¿40 CFR 60 SUBPART GGG ¿40 CFR 63 SUBPART CC ¿LOUISIANA MACT DETERMINATION FOR REFINERY EQUIPMENT LEAKS ¿ JULY 26, 1994	67.51	T/YR		
LA-0225	NORCO REFINERY	LA	DISTILLING UNIT FUGITIVE EMISSIONS 3004-95	50.003				Volatile Organic Compounds (VOC)	N	¿40 CFR 60 SUBPART GGG ¿40 CFR 63 SUBPART CC ¿LOUISIANA MACT DETERMINATION FOR REFINERY EQUIPMENT LEAKS ¿ JULY 26, 1994	182.63	T/YR		
LA-0225	NORCO REFINERY	LA	CATALYTIC REFORMER NO. 2 UNIT FUGITIVE EMISSIONS 3010-95	50.003				Volatile Organic Compounds (VOC)	N	¿40 CFR 60 SUBPART GGG ¿40 CFR 63 SUBPART CC ¿LOUISIANA MACT DETERMINATION FOR REFINERY EQUIPMENT LEAKS ¿ JULY 26, 1994	120.57	T/YR		
LA-0225	NORCO REFINERY	LA	HYDROGEN PLANT FUGITIVE EMISSIONS 5011-99	50.003				Volatile Organic Compounds (VOC)	N	¿40 CFR 63 SUBPART CC ¿LOUISIANA MACT DETERMINATION FOR REFINERY EQUIPMENT LEAKS ¿ JULY 26, 1994	15.41	T/YR		
LA-0228	BATON ROUGE JUNCTION FACILITY	LA	FUG002 FUGITIVE EMISSIONS	42.004				Volatile Organic Compounds (VOC)	P	CONDUCT A LEAK DETECTION AND REPAIR PROGRAM AS SPECIFIED BY 40 CFR 63 SUBPART R	7.44	T/YR	ANNUAL MAXIMUM	
LA-0240	FLOPAM INC.	LA	Equipment Leaks (Fugitives)	69.999		0		Volatile Organic Compounds (VOC)	P	Comply with 40 CFR 65 Subpart F	2	LB/H	HOURLY MAXIMUM	
LA-0245	HYDROGEN PLANT	LA	Hydrogen Plant Fugitives (FUG0030)	50.007		0		Volatile Organic Compounds (VOC)	P	LDAR program that meets LA Refinery MACT with Consent Decree Enhancements (July 26, 1994)	23.74	T/YR		
LA-0257	SABINE PASS LNG TERMINAL	LA	Fugitive Emissions	50.999		0		Volatile Organic Compounds (VOC)	P	Mechanical seals or equivalent for pumps and compressors that serve VOC with vapor pressure of 1.5 psia and above	5.03	LB/H	HOURLY MAXIMUM	
NM-0050	ARTESIA REFINERY	NM	FUGITIVE EQUIPMENT COMPONENTS	50.007	NOT APPLICABLE			Volatile Organic Compounds (VOC)	B		0		SEE NOTE	
OH-0281	RUMPKE SANITARY LANDFILL, INC	OH	FUGITIVE EMISSIONS FROM LANDFILL AND GAS COLLECTION SYSTEM	29.9				Volatile Organic Compounds (VOC)	N		745.7	T/YR	NONMETHANE ORGANIC CARBON	
OH-0281	RUMPKE SANITARY LANDFILL, INC	OH	FUGITIVE EMISSIONS FROM LANDFILL AND GAS COLLECTION SYSTEM	29.9				Methane	N		45029	T/YR		
OH-0292	WHEELING PITTSBURGH STEEL CORPORATION	OH	BASIC OXYGEN FURNACES (2 VESSELS), FUGITIVE EMISSIONS	81.37		375	t/h	Volatile Organic Compounds (VOC)	N		1.13	LB/H		BASIC OXYGEN FURNACE: MATERIAL CHARGING, TAPPING, OXYGEN LANCE, HOOD AND VENTURI SCRUBBER, POST COMBUSTION LANCES, FLAME SUPPRESSION FOR TAPPING, ENHANCED ENCLOSURES OF VESSELS. MAXIMUM STEEL PRODUCTION NOT TO EXCEED 375 TONS/HR AND 5310 TONS/DAY AND 1,640,000 TONS/ROLLING 12-MONTHS.
OH-0294	NUCOR STEEL MARION, INC.	OH	ELECTRIC ARC FURNACE (FUGITIVE EMISSIONS)	81.31	ELECTRICITY	70	T/H	Volatile Organic Compounds (VOC)	N		0.8	T/YR	PER ROLLING 12-MONTHS	RESTRICTION ON HOURS OF OPERATION, SHALL NOT EXCEED 8000 HOURS OF OPERATION PER ROLLING 12-MONTHS. AND NOT TO EXCEED MORE THAN 70 TONS OF STEEL/HR BASED ON A DAILY AVERAGE.
OH-0303	ASA BLOOMINGBURG, LLC	OH	FUGITIVE VOC EMISSIONS LEAKS FROM PROCESS UNITS	70.12	NATURAL GAS	124	MM Gal/YR	Volatile Organic Compounds (VOC)	P	LEAK DETECTION AND REPAIR PROGRAM	7.11	T/YR	FUGITIVE VOCS	LEAKS FRO PROCESS UNITS THAT PRODUCE ORGANIC CHEMICALS EMISSIONS SUBJECT TO 40 CFR PART 60, SUBPART VV, STANDARDS OF PERFORMANCE FOR EQUIPMENT LEAKS OF VOC IN THE SYNTHETIC ORGANIC CHEMICALS MANUGACTURING IND.
OK-0059	PONCA CITY REFINERY	OK	FUGITIVE COMPONENTS/EQUIPMENT LEAKS	50.007				Volatile Organic Compounds (VOC)	P	REFINERY MACT REQUIRES INSPECTION AND MAINTENANCE OF PUMP SEALS, VALVES, FLANGES, AND PIPES	0		REFINERY MACT	All equipment leaks subject to refinery MACT standards

RACT/BACT/LAER Clearinghouse Results for Piping Fugitives
Pollutant: CH4, VOC

RBLCID	FACILITY_NAME	FACILITY_STATE	PROCESS_NAME	PROCCESS_TYPE	PRIMARY_FUEL	THROUGH-PUT	THROUGHPUT_UNIT	POLLUTANT	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	EMISSION_LIMIT_1_AVG_TIME_CONDITION	PROCESS_NOTES"
OK-0089	TPI PETROLEUM INC., VALERO ARDMORE REFINERY	OK	CRUDE UNIT FUGITIVE EMISSIONS	50.003				Volatile Organic Compounds (VOC)	P	LEAK DETECTION AND REPAIR (OVA & METHOD 21)	10000	PPM	leak detection, see notes	
OK-0092	VALERO ARDMORE REFINERY	OK	CRUDE UNIT FUGITIVE EMISSIONS	50.007				Volatile Organic Compounds (VOC)	P	LEAK DETECTION AND REPAIR PROGRAM	0		see note	
OK-0097	QUAD GRAPHICS OKC FAC	OK	PRINTING PRESS, OFFSET (FUGITIVE)	41.023				Volatile Organic Compounds (VOC)	B	VOC LIMITS ON INKS AND THERMAL OXIDIZER. (SEE POLLUTANT NOTES FOR DETAILS.)	112.89	T/YR	NONMETHANE HYDROCARBONS	
OK-0097	QUAD GRAPHICS OKC FAC	OK	INK JET FUGITIVES	41.023				Volatile Organic Compounds (VOC)	A	CLOSED-LOOP SOLVENT RECOVERY SYSTEM	32.78	T/YR	NONMETHANE HYDROCARBONS	
TX-0235	VALERO REFINING COMPANY-CORPUS CHRISTI REFINERY	TX	FUGITIVES	50.007				Volatile Organic Compounds (VOC)	B	EMISSIONS ARE ESTIMATES, NOT MAXIMUM ALLOWABLE RATES. SPECIAL CONDITIONS APPLY FOR MAINTENANCE AND COMPLIANCE OF EQUIPMENT RELATED TO FUGITIVE EMISSIONS OF VOC, SEE PERMIT.	1655	LB/H		FUGITIVE EMISSION POINTS INCLUDE CRUDE UNIT, VACUUM UNIT, LEU, DESALTER UNIT, HDS UNIT, SMR, HRLEU UNIT, LRU, HOC UNIT, BO2F, 30-B-02, 30-B-03, HF ALKYLATION UNIT, BUTAMER UNIT, MTBE, OLEFLEX, SULF/SEU/SRU, HCU, PSA, HNT, CRU, MTBE/TAME UNIT, POWERHOUSE, 49-RSU/XFU, DOCKS, FUEL GAS DRUM, GAS BLENDING, LPG STORAGE, MVRU, TERMINALS, TRUCK RACK. FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED AS A MAXIMUM ALLOWABLE EMISSION RATE. EXTENSIVE SPECIAL CONDITIONS FOR MAINTENANCE AND OPERATION OF FUGITIVE EMISSIONS CONTROL AND EQUIPMENT, SEE PERMIT.
TX-0351	WEATHERFORD ELECTRIC GENERATION FACILITY	TX	PIPING FUGITIVES, FUGIT EPN-5	19.9				Volatile Organic Compounds (VOC)	N	NONE INDICATED	0.44	LB/H		
TX-0352	BRAZOS VALLEY ELECTRIC GENERATING FACILITY	TX	NAT GAS PIPING FUGITIVES, FUG-P	19.9				Volatile Organic Compounds (VOC)	N	NONE INDICATED	0.346	LB/H		
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	ACROLEIN PROCESS FUGITIVES, ACRO-FUG	64.002				Volatile Organic Compounds (VOC)	P	GOOD ENGINEERING PRACTICES AND PROCEDURES OF LEAK DETECTION (28 VHP LDAR), ISOLATION, AND REPAIR	0.07	LB/H		FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	ACROLEIN STORAGE TANKS FUGITIVES, ACRO-TKSFUG	64.004				Volatile Organic Compounds (VOC)	P	FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H		FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	ACROLEIN WASTEWATER FUGITIVES, ACRO-WWFUG	64.006				Volatile Organic Compounds (VOC)	B	FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR. ALL ACROLEIN WW STORAGE TANKS SHALL VENT TO EPN SULFOX-TO	0.01	LB/H		FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	TRAIN 1- ETSH OR TBM PRODUCTION FUGITIVES	64.002				Volatile Organic Compounds (VOC)	P	FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR.	0.3	LB/H		EPN: BMT-1E/T. FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE. THE BMT-1 UNIT CAN PRODUCE EITHER MESH, ETSH, OR TBM. THEREFORE, EMISSIONS FROM BMT-1M AND BMT-1E/T DO NOT OCCUR SIMULTANEOUSLY
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	TRAIN 1 - MESH PRODUCTION FUGITIVES	64.002				Volatile Organic Compounds (VOC)	P	FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR.	0.05	LB/H		EPN: BMT-1M. FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE. THE BMT-1 UNIT CAN PRODUCE EITHER MESH, ETSH, OR TBM. THEREFORE, EMISSIONS FROM BMT-1M AND BMT-1E/T DO NOT OCCUR SIMULTANEOUSLY
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	TRAIN 2- MESH PRODUCTION FUGITIVES	64.002				Volatile Organic Compounds (VOC)	P	FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR.	0.08	LB/H		EPN: BMT-2M. FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	THERMAL OXIDIZER PROCESS FUGITIVES	64.003				Volatile Organic Compounds (VOC)	P	FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H		EPN: TO-FUG. FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHALL NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	TANK TRUCK LOADING/UNLOADING FUGITIVES	64.005				Volatile Organic Compounds (VOC)	P	SEE POLLUTANT NOTES. FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR	0.03	LB/H		EPN: TTSHIP. FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	SOUR WATER STRIPPERS FUGITIVES	64.006				Volatile Organic Compounds (VOC)	B	FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR. EMISSIONS FROM ANY VOC WATER SEPARATION EQUIPMENT SHALL BE VENTED TO A PERMITTED CONTROL DEVICE OR RECYCLED TO THE PROCESS	0.01	LB/H		EPN: SWS. FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	PRODUCT RECOVERY TOWER FUGITIVES	64.999				Volatile Organic Compounds (VOC)	P	FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR.	0.02	LB/H		EPN: PR-TOWER. FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE.

RACT/BACT/LAER Clearinghouse Results for Piping Fugitives
Pollutant: CH4, VOC

RBLCID	FACILITY_NAME	FACILITY_STATE	PROCESS_NAME	PROCCESS_TYPE	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	POLLUTANT	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	EMISSION_LIMIT_1_AVG_TIME_CONDITION	PROCESS_NOTES"
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	RAILCAR LOADING/UNLOADING FUGITIVES	64.005				Volatile Organic Compounds (VOC)	P	SEE POLLUTANT NOTES. FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR	0.03	LB/H		EPN: RCSHIP. FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHALL NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	DIMETHYL DISULFIDE AREA PROCESS FUGITIVES	64.002				Volatile Organic Compounds (VOC)	P	FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR.	0.06	LB/H		EPN: DMDS. FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	RUNDOWN TANK FUGITIVES	64.999				Volatile Organic Compounds (VOC)	B	MMP DAY STORAGE TANKS WILL VENT TO THE MMP BULK STORAGE TANK WHICH WILL VENT TO SULF0X-TO. FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR	0.11	LB/H		EPN: RUNDOWN. FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	STORAGE TANKS FUGITIVES	64.004				Volatile Organic Compounds (VOC)	B	MMP DAY STORAGE TANKS WILL VENT TO THE MMP BULK STORAGE TANK WHICH WILL VENT TO SULF0X-TO. FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR	0.16	LB/H		EPN: STORAGE. FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	DIMETHYL SULFIDE AREA PROCESS FUGITIVES	64.002				Volatile Organic Compounds (VOC)	P	FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR.	0.02	LB/H		EPN: DMS. FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	H2S PLANT PROCESS FUGITIVES	64.002				Volatile Organic Compounds (VOC)	P	FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H		FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	FLARE AREA FUGITIVES	19.31				Volatile Organic Compounds (VOC)	P	FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H		EPN: FAREFUG. FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED AS A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	INCINERATOR PROCESS FUGITIVES	64.999				Volatile Organic Compounds (VOC)	P	28VHP LDAR	0.01	LB/H		EPN: FUG-INCIN. FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	MMP PROCESS AREA FUGITIVES	64.002				Volatile Organic Compounds (VOC)	P	FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR.	0.13	LB/H		EPN: MMP-FUG. FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	MMP RAILCAR LOADING AREA PROCESS FUGITIVES	64.005				Volatile Organic Compounds (VOC)	P	SEE POLLUTANT NOTES	0.01	LB/H		EPN: MMPRC-FUG
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	MMP STORAGE AREA PROCESS FUGITIVES	64.004				Volatile Organic Compounds (VOC)	P	SEE POLLUTANT NOTES. FOLLOW PRACTICES OF GOOD ENGINEERING, LEAK DETECTION, ISOLATION, AND REPAIR	0.01	LB/H		EPN: MMPTKS-FUG. FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0364	SALT CREEK GAS PLANT	TX	FUGITIVES, NGLFUG	50.007				Volatile Organic Compounds (VOC)	N	NONE INDICATED	9.08	LB/H		
TX-0364	SALT CREEK GAS PLANT	TX	FUGITIVES, CO2FUG	50.007				Volatile Organic Compounds (VOC)	N	NONE INDICATED	9.33	LB/H		
TX-0373	ODESSA PETROCHEMICAL PLANT	TX	FUGITIVES	69.999				Volatile Organic Compounds (VOC)	P	28VHP PROGRAM	7.85	LB/H		
TX-0374	CHOCOLATE BAYOU PLANT	TX	NAT GAS & FUEL GAS FUGITIVES	19.9	NAT GAS			Volatile Organic Compounds (VOC)	N	NONE INDICATED	0.45	LB/H		
TX-0376	DOW TEXAS OPERATIONS FREEPORT	TX	PIPING FUGITIVES, PROJECT B, B73FU01	19.9				Volatile Organic Compounds (VOC)	N	NONE INDICATED	0.136	LB/H		
TX-0376	DOW TEXAS OPERATIONS FREEPORT	TX	TURBINE LUBRICATION FUGITIVES, PROJECT A, A50V1	19.9				Volatile Organic Compounds (VOC)	N	NONE INDICATED	0.006	LB/H		
TX-0376	DOW TEXAS OPERATIONS FREEPORT	TX	PIPING FUGITIVES, PROJECT A, A50FU01	19.9				Volatile Organic Compounds (VOC)	N	NONE INDICATED	0.136	LB/H		
TX-0376	DOW TEXAS OPERATIONS FREEPORT	TX	TURBINE LUBRICATION FUGITIVES, PROJECT B, B73V4	19.9				Volatile Organic Compounds (VOC)	N	NONE INDICATED	0.006	LB/H		
TX-0379	EXXONMOBIL BEAUMONT REFINERY	TX	FCCU FUGITIVES	50.007				Volatile Organic Compounds (VOC)	P	FOLLOW PROCEDURES FOR LEAK PREVENTION, DETECTION, AND REPAIR.	9.84	LB/H		
TX-0379	EXXONMOBIL BEAUMONT REFINERY	TX	FCCU FUGITIVES (PRESCRUBBER), 06FG-001	50.007				Volatile Organic Compounds (VOC)	P	FOLLOW PROCEDURES FOR LEAK PREVENTION, DETECTION, AND REPAIR.	9.85	LB/H		
TX-0422	BP TEXAS CITY CHEMICAL PLANT B	TX	FUGITIVES	64.002				Volatile Organic Compounds (VOC)	P	LEAK INSPECTION AND MONITORING, REPAIR AND MAINTENANCE	0		SEE NOTE	PIPING, VALVES, CONNECTORS, PUMPS, AND COMPRESSORS

RACT/BACT/LAER Clearinghouse Results for Piping Fugitives
Pollutant: CH4, VOC

RBLCID	FACILITY_NAME	FACILITY_STATE	PROCESS_NAME	PROCCESS TYPE	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	POLLUTANT	CONTROL METHOD CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	EMISSION_LIMIT_1_AVG_TIME_CONDITION	PROCESS_NOTES"
TX-0440	CORPUS CHRISTI LNG	TX	FUGITIVES (4)	50.007				Volatile Organic Compounds (VOC)	N		1.96	LB/H		
TX-0449	UCC SEADRIFT OPERATIONS	TX	RXN AND ETHYLENE PURIFICATION FUGITIVES (8)	50.007				Volatile Organic Compounds (VOC)	N		6.04	LB/H		
TX-0449	UCC SEADRIFT OPERATIONS	TX	AREA FUGITIVES (4)	64.002				Volatile Organic Compounds (VOC)	A		4.99	LB/H		
TX-0451	DIAMOND SHAMROCK REFINING VALERO	TX	COMBUSTION UNITS, TANKS, PROCESS VENTS, LOADING, FLARES, FUGITIVES (4), WASTEWATER, COOLING	19.9				Volatile Organic Compounds (VOC)	N		392.62	LB/H		SOURCES ARE COMBUSTION UNITS, TANKS, PROCESS VENTS, LOADING, FLARES, FUGITIVES (4), WASTEWATER, COOLING TOWERS
TX-0453	BAYPORT ENERGY CENTER	TX	FUGITIVES	64.002				Volatile Organic Compounds (VOC)	N		0.2	LB/H		
TX-0454	EL PASO NATURAL GAS CORNUDAS COMPRESSOR STATION	TX	FUGITIVES (4)	64.002				Volatile Organic Compounds (VOC)	N		0.13	LB/H		
TX-0457	CITY PUBLIC SERVICE LEON CREEK PLANT	TX	PLANT FUGITIVES (4)	64.002				Volatile Organic Compounds (VOC)	N		0.07	LB/H		
TX-0465	SALT CREEK GAS PLANT	TX	FUGITIVES (4)	64.002				Volatile Organic Compounds (VOC)	N		9.08	LB/H		
TX-0465	SALT CREEK GAS PLANT	TX	FUGITIVES	64.002				Volatile Organic Compounds (VOC)	N		9.33	LB/H		
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	MDHU FUGITIVES 2	50.007				Volatile Organic Compounds (VOC)	N		25.5	LB/H		
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	SRU PROCESS FUGITIVES (4)	50.007				Volatile Organic Compounds (VOC)	N		1.2	LB/H		
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	COKER UNIT FUGITIVES (4)	50.007				Volatile Organic Compounds (VOC)	N		35.8	LB/H		
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	WP MEROX FUGITIVES	50.007				Volatile Organic Compounds (VOC)	N		8.5	LB/H		
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	DHT FUGITIVES	50.007				Volatile Organic Compounds (VOC)	N		5.7	LB/H		
TX-0479	DOW TEXAS OPERATIONS FREEPORT	TX	TURBINE LUBRICATION FUGITIVES	50.007				Volatile Organic Compounds (VOC)	N		0.006	LB/H		
TX-0479	DOW TEXAS OPERATIONS FREEPORT	TX	PIPING FUGITIVES FOR BOILERS (5)	50.007				Volatile Organic Compounds (VOC)	N		0.136	LB/H		
TX-0479	DOW TEXAS OPERATIONS FREEPORT	TX	PIPING FUGITIVES FOR TURBINES (5)	50.007	NATURAL GAS			Volatile Organic Compounds (VOC)	N		0.05	LB/H		
TX-0479	DOW TEXAS OPERATIONS FREEPORT	TX	TURBINE LUBRICATION FUGITIVES (5)	50.007				Volatile Organic Compounds (VOC)	N		0.01	LB/H		
TX-0481	AIR PRODUCTS BAYTOWN I I	TX	FUGITIVES (4)	50.007				Volatile Organic Compounds (VOC)	N		0.23	LB/H		THE CO EMISSIONS ARE ELIGIBLE FOR PSD
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	FUGITIVES (4)	50.007				Volatile Organic Compounds (VOC)	N		0.05	LB/H		ACH: .22 LB/H .98 T/YR
TX-0492	VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	TX	FUGITIVES (4)	50.007	SWEET NATURAL GAS			Volatile Organic Compounds (VOC)	N		0.88	LB/H		TOTAL UNCONTROLLED FUGITIVE EMISSIONS ARE LESS THAN 10 TPY, SO NO MONITORING IS REQUIRED. THE COMPANY WILL IMPLEMENT DAILY WALKTHROUGHS TO INSPECT THE PIPING. THERE ARE ALSO H2S MONITORS ON SITE TO CAPTURE ANY H2S LEAKS.
TX-0495	NEW LANDFILL GAS (LFG) FUELED POWER GENERATION FACILITY	TX	FUGITIVES (4)	50.007				Volatile Organic Compounds (VOC)	N		0.04	LB/H		
TX-0505	CERTAINTEED INSULATION FIBER GLASS AND DUCTLINER MANUFACTURI	TX	BI/LI LINE FREHEAT FUGITIVES (8)	90.015				Volatile Organic Compounds (VOC)	N		0.04	LB/H		EMISSIONS ARE PER LINE (BI AND LI)
TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	TX	BATCH DIGESTOR FUGITIVES	30.219				Volatile Organic Compounds (VOC)	N		4.8	LB/H		
TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	TX	WASTE WATER TREATMENT FUGITIVES	30.219				Volatile Organic Compounds (VOC)	N		348.16	LB/H		

RACT/BACT/LAER Clearinghouse Results for Piping Fugitives
Pollutant: CH4, VOC

RBLCID	FACILITY_NAME	FACILITY_STATE	PROCESS_NAME	PROCCESS_TYPE	PRIMARY_FUEL	THROUGH-PUT	THROUGHPUT_UNIT	POLLUTANT	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	EMISSION_LIMIT_1_AVG_TIME_CONDITION	PROCESS_NOTES"
VA-0313	TRANSMONTAIGNE NORFOLK TERMINAL	VA	Truck Loading Fugitive Emissions from Loading Rack LR-1	42.009		0		Volatile Organic Compounds (VOC)	N		9.3	T/YR		
VA-0313	TRANSMONTAIGNE NORFOLK TERMINAL	VA	Fugitive emissions (valves, flanges, etc.)	42.009		0		Volatile Organic Compounds (VOC)	N		0.2	T/YR		
WI-0204	UWGP - FUEL GRADE ETHANOL PLANT	WI	FUGITIVE VOC, FROM EQUIPMENT, F01	64.002				Volatile Organic Compounds (VOC)	P	SOCMI LEAK DETECTION AND REPAIR	0		see note	Subject to NSPS
WI-0251	ENBRIDGE ENERGY	WI	F01 - NEW AND MODIFIED TANKS, NEW PIPELINES, AND ASSOCIATED FUGITIVE VOC	42.006				Volatile Organic Compounds (VOC)	P	USE OF AN INSTRUMENT BASED LEAK DETECTION AND REPAIR (LDAR) PROGRAM, COMBINED WITH NON-INSTRUMENTAL METHODS (SIGHT, SOUND AND SMELL), AND GOOD OPERATING PRACTICES	0			VOC LEAKS FROM NEW AND MODIFIED TANK PIPING, NEW PIPING MANIFOLDS, AND OTHER NEW PIPING, PUMPS, VALVES , ETC. ASSOCIATED WITH THE NEW PIPELINES.

RACT/BACT/LAER Clearinghouse Results for
Furance Decoke
Pollutant: CO_2

RBLCID	FACILITY_NAME	CORPORATE_OR_COMPANY_NAME	FACILITY_STATE	PERMIT_NOTES	PROCESS_NAME	PROCCESS_TYPE	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	PROCESS_NOTES"	POLLUTANT	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	EMISSION_LIMIT_1_AVG_TIME_CONDITION
TX-0475	FORMOSA POINT COMFORT PLANT	FORMOSA PLASTICS CORPORATION TEXAS	TX		DECOKE DRUM (5)	50.003				EMISSIONS ARE THE TOTAL OF THE FIVE DRUMS	Volatile Organic Compounds (VOC)	N		0.01	LB/H	
TX-0475	FORMOSA POINT COMFORT PLANT	FORMOSA PLASTICS CORPORATION TEXAS	TX		DECOKE DRUM (5)	50.003				EMISSIONS ARE THE TOTAL OF THE FIVE DRUMS	Carbon Monoxide	N		76.6	LB/H	
TX-0475	FORMOSA POINT COMFORT PLANT	FORMOSA PLASTICS CORPORATION TEXAS	TX		DECOKE DRUM (5)	50.003				EMISSIONS ARE THE TOTAL OF THE FIVE DRUMS	Particulate matter, filterable < 10 µ (FPM10)	N		7.05	LB/H	

RACT/BACT/LAER Clearinghouse Results for Thermal Oxidizer
Pollutant: CO2e

RBLCID	FACILITY_NAME	PERMIT_TYPE	PROCESS_NAME	PROCCESS_TYPE	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	POLLUTANT	POLLUTANT_GROUP(S)	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	EMISSION_LIMIT_1_AVG_TIME_CONDITION
*DE-0023	NRG ENERGY CENTER DOVER	U	UNIT 2- KD1	15.21	Natural Gas	655	MMBTU/hr	Carbon Dioxide Equivalent (CO2e)	(Greenhouse Gasses (GHG))	N		1085	LBS/GROSS MWH	12 MONTH ROLLING AVERAGE
GA-0147	PYRAMAX CERAMICS, LLC - KING'S M:U FACILITY	A	BOILERS	19.6	NATURAL GAS	9.8	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	(Greenhouse Gasses (GHG))	P	Good Combustion Practices, design, and thermal insulation.	5809	T/12-MO ROLLING AVG	
GA-0147	PYRAMAX CERAMICS, LLC - KING'S M:U FACILITY	A	CALCINERS/KILNS	90.017	NATURAL GAS	4.9	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	(Greenhouse Gasses (GHG))	P	Good Heat Insulation, Heat Recovery, Good Combustion Practices	436	LB/T	PROD OF CO2E, 12-MO ROLL TOTAL
IA-0105	IOWA FERTILIZER COMPANY	A	Primary Reformer	61.012	natural gas	1.13	million cubic feet/h	Carbon Dioxide Equivalent (CO2e)	(Greenhouse Gasses (GHG))	P	good combustion practices	596905	TONS/YR	ROLLING 12 MONTH TOTAL
IA-0105	IOWA FERTILIZER COMPANY	A	Auxiliary Boiler	11.31	natural gas	472.4	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	(Greenhouse Gasses (GHG))	P	good combustion practices	51748	TONS/YR	ROLLING 12 MONTH TOTAL
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	B	Boilers	11.31	natural gas	456	MMBTU/hr	Carbon Dioxide Equivalent (CO2e)	(Greenhouse Gasses (GHG))	P	proper operation and use of natural gas	234168	TONS/YR	ROLLING TWELVE (12) MONTH TOTAL
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	B	Primary Reformer	61.012	natural gas	1062.6	MMBTU/hr	Carbon Dioxide Equivalent (CO2e)	(Greenhouse Gasses (GHG))	P	good operating practices and use of natural gas	545674	TONS/YR	ROLLING TWELVE (12) MONTH TOTAL
*LA-0266	EUNICE GAS EXTRACTION PLANT	B	Boiler B-101-G (12-1) (EQT 0061)	11.31	Natural gas	359	MM Btu/hr	Carbon Dioxide Equivalent (CO2e)	(Greenhouse Gasses (GHG))	P	Energy efficiency measures: improved combustion measures (e.g., combustion tuning, optimization using parametric testing, advanced digital instrumentation such as temperature sensors, oxygen monitors, CO monitors, and oxygen trim controls); use of an economizer; boiler insulation; and minimization of air infiltration.	0		
*MI-0404	GERDAU MACSTEEL, INC.	D	Caster (EUCASTER)	81.23	Natural gas	130	T/H liquid steel	Carbon Dioxide Equivalent (CO2e)	(Greenhouse Gasses (GHG))	N	Energy efficiency practices	0		

RACT/BACT/LAER Clearinghouse Results for Thermal Oxidizer
Pollutant: CO2e

RBLCID	FACILITY_NAME	PERMIT_TYPE	PROCESS_NAME	PROCCESS_TYPE	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	POLLUTANT	POLLUTANT_GROUP(S)	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	EMISSION_LIMIT_1_AVG_TIME_CONDITION
*MI-0404	GERDAU MACSTEEL, INC.	D	Slidegate Heater (EUSLIDEGATEHEATER)	81.29	Natural gas	0		Carbon Dioxide Equivalent (CO2e)	(Greenhouse Gasses (GHG))	N	Energy efficiency practices	0		
*NE-0054	CARGILL, INCORPORATED	B	Boiler K	11.31	natural gas	300	mmbtu/h	Carbon Dioxide Equivalent (CO2e)	(Greenhouse Gasses (GHG))	P	good combustion practices	0		

Appendix E
Other Information

Solomon Associates

M³ — Measure. Manage. Maximize.

November 28, 2012

Mr. John Holderness
Dow Chemical Company

Dear Mr. Holderness,

Per your request, we have compared the energy performance data for the LHC-9 proposed design to the data from the *Worldwide Olefin Plant Performance Analysis (Olefin Study)* for operating year 2011. The *Olefin Study*, conducted biennially by Solomon Associates, is the most comprehensive standard by which ethylene plants are benchmarked on all facets of performance, including energy consumption and energy efficiency. The 115 olefin plants participating in the 2011 study represents more than 60% of the world's ethylene capacity and more than 85% of North America's ethylene capacity.

As a measure of thermal efficiency and effective heat recovery in the pyrolysis furnaces, we compared the design furnace flue gas stack temperature to some peer averages for the 2011 study. The proposed LHC-9 stack temperature varies depending on feedstock; therefore, a range of values is given for comparison. The proposed LHC-9 stack temperature would be:

- 64–86 °F below the Dow company average stack temperature
- 43–65 °F below the Total Study average stack temperature
- 80–102 °F below the North American average stack temperature

The basic method of measuring energy consumption in the study is to calculate the energy consumed per unit of product. The *Olefin Study* uses Btu (lower heating value or LHV) per pound of High-Value Chemicals or HVC (ethylene, propylene, butadiene, benzene, and hydrogen). This includes all energy consumed by the plant: fuel, steam, and electric power. The energy consumption for the proposed design for LHC-9 would be:

- The top-ranked plant in energy consumption [in Btu (LHV) per pound of HVC] among the global group of 19 ethane-feed olefin plants participating in the 2011 study
- In the top 10% of North American plants of all feedstock types ranked on energy consumption

Solomon gives full permission for Dow to share this letter with the regulating authorities for your greenhouse gas (GHG) permit application.

Sincerely,

Claire L. Cagnolatti

Claire L. Cagnolatti
Vice President of Chemicals Studies

Two Galleria Tower ■ 13455 Noel Road, Suite 1500 ■ Dallas, Texas 75240 ■ Phone: +1.972.739.1700
Dallas ■ Houston ■ London ■ Moscow ■ Tokyo ■ Beijing ■ Seoul ■ Jakarta ■ Singapore ■ Khobar ■ Manama