Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Dow Chemical Company, Freeport Light Hydrocarbons 9 Olefins Plant

Permit Number: PSD-TX-1328-GHG

This document serves as the statement of basis (SOB) for the above-referenced draft permit, as required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On November 28, 2012, The Dow Chemical Company – Freeport, Texas (Dow) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for a proposed new ethylene production project named the Light Hydrocarbon Plant No. 9 (LHC-9) located near Freeport, Brazoria County, Texas. The project includes construction and operation of a new ethylene unit and associated utilities. The plant will process hydrocarbon feedstocks (ethane and propane) to produce nominally 1.5 MM tons per year ethylene and other high value products such as propylene, butadiene, and hydrogen.

The new unit will include eight (8) new steam cracking furnaces (five ethane and three ethane or propane 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 cooling tower, a flare system (one low pressure elevated and one ground pressure assist flare), and a waste gas thermal oxidizer is included.

The operating schedule for this facility is 8760 hours per year. This permit authorizes the emissions of GHGs from this project, the TCEQ permit 107153/PSD-TX-1328 addresses emissions of non-GHG air contaminants (both PSD and Non Attainment New Source Review (NNSR)) for the same project.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that Dow's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by Dow, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

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III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305).

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

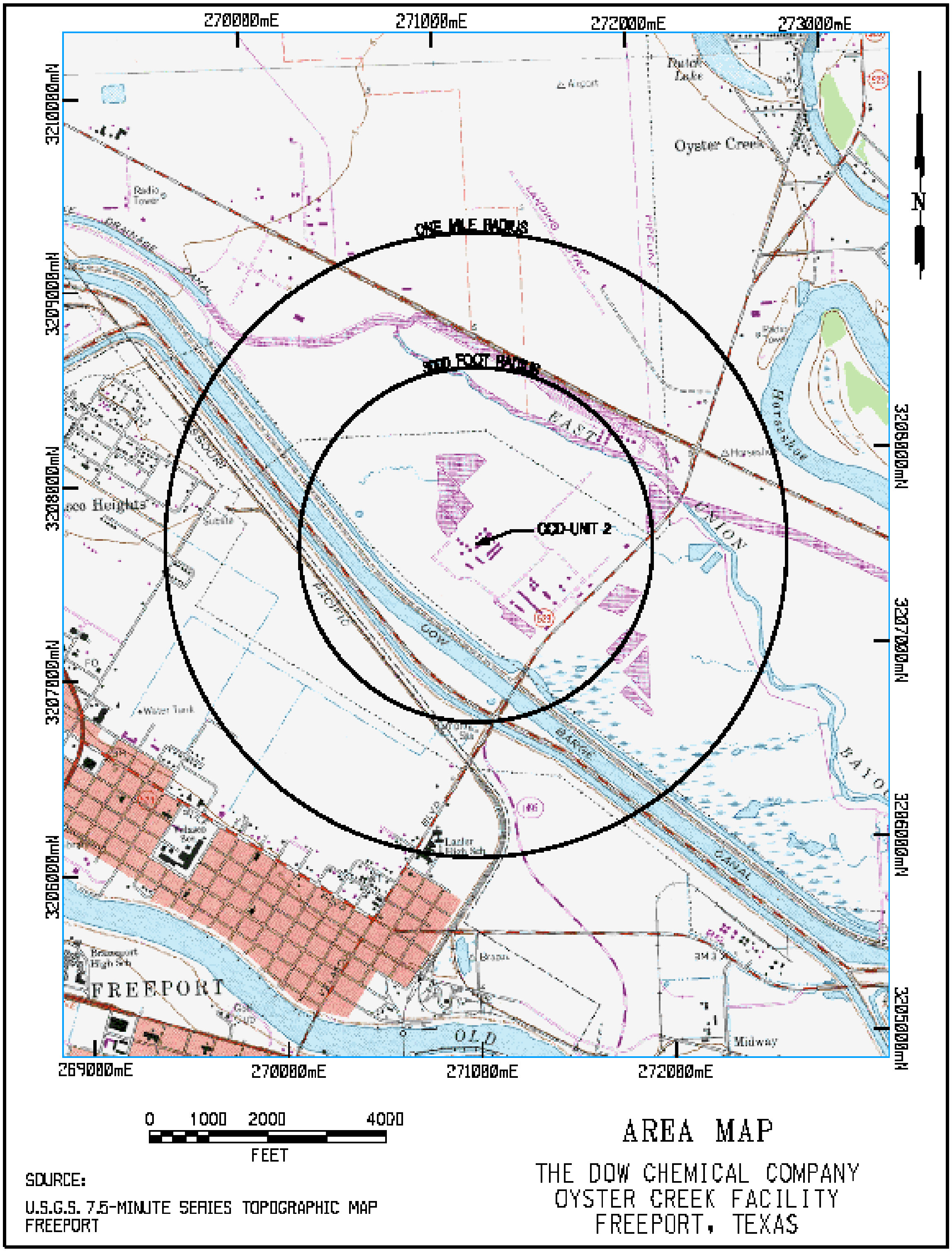
The EPA, Region 6 Permit Writer is:
Brad Toups
Air Permitting Section (6PD-R)
(214) 665-7258

IV. Facility Location

The Dow LHC-9 facility is located in Brazoria County, Texas. The geographic coordinates for this facility are as follows:

Latitude: 28º 58’ 40” North
Longitude: - 95º 20’ 57” West

Brazoria County is currently designated severe nonattainment for ozone, and is currently designated attainment for all other pollutants. The nearest Class I area, at a distance of more than 500 kilometers, is Breton National Wildlife Refuge. The plot plan for the Dow Freeport LHC-9 facility is depicted in Attachment A. The facility location map is here:



V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA concludes Dow's application is subject to PSD review for the pollutant GHGs, because the project would lead to an emissions increase of GHGs for a facility in excess of the emission thresholds described at 40 CFR § 52.21 (b)(49)(v). The facility is an existing major stationary source (as well as a source with a PTE that equals or exceeds 100,000 TPY CO_2e and 100/250TPY GHGs mass basis), and the planned modification has a GHG emissions increase that equals or exceeds 75,000 TPY CO_2e (and 0 TPY GHGs mass basis). Dow calculated a CO_2e emissions increase of 2,361,294 tpy for the proposed project.

EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305. EPA Region 6 considers the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases." As recommended in that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, and we have not required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with BACT is the best technique that can be employed at present to satisfy additional impacts analysis and Class I area requirements of the rules as they relate to GHGs. The applicant submitted an analysis to meet the requirements of 40 CFR § 52.21(o), as it may otherwise apply to the project. EPA's PSD permitting action will only authorize emissions of GHGs.

VI. Project 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, a new waste gas thermal oxidizer, and new flare system will be constructed. The operating schedule for this facility is 8760 hours per year.

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 (NO_X). Ammonia is the reducing agent that will be used in the SCR system to for chemical reduction of the NO_X. 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 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.

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.

Sources of GHG emissions at the LHC-9 facility

While there are over 40 individually listed emissions units at the site, only 15 of those are potential sources of GHG emissions. Therefore, the remainder of this review addresses only these 15 sources. The sources (Facility Identification Numbers, FINs) and their corresponding Emissions Point Numbers (EPNs) are listed in Table 1.

Table 1. GHG emissions sources of LHC-9

EPN	FIN	Description
OC2H121 OC2H122 OC2H123 OC2H124 OC2H125	OC2L9H121 OC2 L9H122 OC2 L9H123 OC2 L9H124 OC2 L9H125	Ethane Cracking Furnace, F-121 Ethane Cracking Furnace, F-122 Ethane Cracking Furnace, F-123 Ethane Cracking Furnace, F-124 Ethane Cracking Furnace, F-125
OC2H126 OC2H127 OC2H128	OC2 L9H126 OC2 L9H127 OC2 L9H128	Ethane or Propane Cracking Furnace, F-126 Ethane or Propane Cracking Furnace, F-127 Ethane or Propane Cracking Furnace, F-128
OC2TOX	OC2L9TOX	LHC-9 Thermal Oxidizer (LHC-9TOX)
OC2C597	OC2L9F597	Low Pressure Flare, FS-597
OC2F5961	OC2L9F596	Pressure Assisted Flare, GF-596
OC2FU2	OC2L9FU2	Process Area Fugitives
OC2CT936	OC2L9CT936	Cooling Tower CT-936 Heat Exchanger System
OC2GE1 OC2GE2	OC2L9GE1 OC2L9GE2	Backup Generator No. 1 Backup Generator No. 2

Steam Cracking Furnaces
The cracking section consists of 8 furnaces of proprietary design (EPNs: OC2H121 through OC2H128). Five are designed to crack ethane feedstock, while three are designed to crack either ethane or propane feedstock. 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 NO_x, 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 NO_x, CO, and PM emissions. SCR systems are also included on the furnaces to further control NO_x emissions.

Combustion Device 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.

The pilot for the flares and the thermal ozidizer utilize natural gas as fuel, while the emergency generators are fired on low sulfur diesel fuel.

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 thus eliminating the decoke vents as a source of GHG emissions to atmosphere. A furnace operates for approximately fifty (50) days between decokes.

Flares and Thermal Oxidizer
The flare system consists of a small volume elevated flare (LP Flare, EPN: OC2F597) and a pressure-assisted ground flare (EPN: OC2F5961) as well as a thermal oxidizer. The thermal oxidizer (TOX, EPN: OC2TOX) 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. 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.

Both 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 Highly Reactive Volatile Organic Compound (HRVOC, 30 TAC Chapter 115, subchapter H) and Federal 40 CFR §60.18 requirements.

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 of the application updates of September 9, 2013, December 19, 2013 and January 24, 2014. 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.

Equipment Leak Fugitive Sources
Leaks of GHG emissions, primarily methane, are possible from the cooling tower heat exchanger system (EPN: OC2CT936) and the various components (seals, valves, piping components, flanges, ect) used to transport fuel gas, process fluids, and waste gases (EPN: OC2L9FU) at the site. Individually, such components are not large emissions sources when operated and maintained in good working condition, but collectively, uncontrolled, they can be a significant source of methane emissions.

As there are no established GHG piping fugitive emission factors, Dow used 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. The cooling tower heat exchanger system estimates of leak rate are based on expected composition of the streams serviced by the cooling tower. Under various directed maintenance programs to be implemented by Dow (expected control efficiency about 99%), the total emissions between these two sources are relatively small (≈106 tpy CO_2e) compared with the cracking furnaces or controlled waste gas streams.

Backup Diesel Generators

Dow anticipates employing two low sulfur diesel fuel fired electrical generators (EPNs: OC1GE1 and OC1GE2) at the site for use in emergency backup service, anticipating less than 100 hours operation annually each. Collectively, these two generators are anticipated to contribute approximately 33 tpy CO_2e to the project.

VII General Format of the BACT Analysis

The BACT analyses for this draft permit considered the recommendations in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines the steps for conducting a "top-down" BACT analysis. Those steps are listed as follows:

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies;
(4) Evaluate the most effective controls and document the results; and,
(5) Select BACT.

VIII Applicable Emission Units and BACT Discussion

See Table 2 below for the GHG emissions sources and allowable emissions for this project. As can be seen in a review of Table 2, below, the vast majority of the contribution of GHGs associated with the project is from combustion sources, with over 97% of those controlled emissions originating with the eight cracking furnaces. All the sources listed in Table 2 are subject to BACT review in this project. Since the total 99.87% of the CO_2e emissions are from CO_2, this BACT analysis focuses on that contaminant for the combustion sources and on methane for the equipment leak fugitive emissions.

Table 2. Proposed Annual GHG Emissions Limitations for LHC-9 GHG sources						
EPN	**FIN**	**Description**	**GHG Mass Basis Emission Rates**		**CO_2e**	**% of Total Project CO_2e Emissions**
			Pollutant	Ton per Year Per EPN	Ton per Year Per EPN	
OC2H121 OC2H122 OC2H123 OC2H124 OC2H125	OC2L9H121 OC2L9H122 OC2L9H123 OC2L9H124 OC2L9H125	Cracking Furnace, F-121 Cracking Furnace, F-122 Cracking Furnace, F-123 Cracking Furnace, F-124 Cracking Furnace, F-125	CO_2 CH_4 N_2O	278,357 5.19 0.52	278,641	58.95%
OC2H126 OC2H127 OC2H128	OC2L9H126 OC2L9H127 OC2L9H128	Cracking Furnace, F-126 Cracking Furnace, F-127 Cracking Furnace, F-128	CO_2 CH_4 N_2O	301,855 5.63 0.56	302,164	38.35%
OC2F597	OC2L9F597	Low Pressure Flare, FS-597	CO_2 CH_4 N_2O	14,034 0.22 0.02	14,046	0.59%
OC2F5961	OC2L9F596	Pressure-Assisted Flare, GF-596	CO_2 CH_4 N_2O	43,910 2.13 0.42	44,089	1.87%
OC2TOX	OC2L9TOX	LHC-9 TOX	CO_2 CH_4 N_2O	3,320 0.06 0.007	3,324	0.14%
OC2FU2	OC2L9FU2	Process Area Fugitives	CO_2 CH_4	0.02 3.82	81[1]	<0.01%
OC2CT936	OC2L9CT936	Cooling Tower CT-936 Heat Exchanger System	CH_4	1	25[1]	<0.01%
OC2GE1 OC2GE2	OC2L9GE1 OC2L9GE2	Backup Diesel Generator No. 1 Backup Diesel Generator No. 2	CO_2 CH_4 N_2O	16.04 0.001 0.0001	17	<0.01%
Total of all facilities authorized by this permit			CO_2 CH_4 N_2O	2,358,647 50.07 4.73	2,361,294	100.00%

[1] Fugitive missions are estimates only and not annual limitations but are controlled thru BACT workpractices.

A. BACT Evaluation for Steam Cracking Furnaces and Recovery Section.

Dow searched the EPA RACT/BACT/LAER Clearinghouse (RBLC) database only for applicable CO_2 BACT determinations to assist in identifying potential control technologies relevant to the proposed emissions sources. Dow's RBLC Database search revealed that, in addition to using lower CO_2 emitting fuels, there are only two methods for potentially reducing and controlling CO_2 emissions. These controls are improved energy efficiency and carbon capture and storage (sequestration), and these two are included in this BACT analysis.

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.

CRACKING FURNACES

BACT Step 1- Identify Available Control Technologies

Add on control technology, in the form of carbon capture and sequestration is considered an "available control" for GHG from a variety of combustion sources.[1] Of the non-capture methods, the ways to minimize combustion related GHG emissions is through minimizing the emissions using a combination of thermal efficiency which is achieved through design and operations and results in less fuel used per unit product, and lower carbon content fuels that meet the requirements of the process. Consequently, the following technologies were identified as potential control options for the furnaces based on review of available information and data sources:

(a) Carbon Capture and Storage (CCS) as an add-on control.

(b) Energy and Thermal Efficient Design

  (1) overall plant and furnace and recovery sections

  (2) oxygen trim control and good combustion practices

  (3) periodic tune ups and maintenance

(c) Use of Low-Carbon Gaseous Fuels

BACT Step 2- Eliminate Technically Infeasible Options

(a) Carbon Capture and Sequestration

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.

Capture and Compression - 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. Other potential absorption and membrane technologies are being developed.

[1] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> (March 2011)

According to the U.S. Department of Energy's National Energy Technology Laboratory (DOE-NETL)[2] 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.

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 CO2 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[3] and would also result in an overall loss of energy efficiency.

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

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[2] DOE-NETL, Carbon Sequestration: FAQ Information Portal, http://www.netl.doe.gov/technologies/carbon_seq/faqs.html
[3] *ibid*
[4] Denbury, Green Pipeline Projects, available at http://www.denbury.com/operations/gulf-coast-region/co2-sources-and-pipelines/default.aspx (last visited February 10, 2014).

enhanced oil recovery (EOR) site is approximately 40 miles from Dow Freeport; however, there is no existing connection to the pipeline for Hastings Field.

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- EOR. CO_2 is injected into the well dissolving into the oil, causing it to swell, thus making it flowable to producing wells.

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, according to Dow, these limestone formations have not been demonstrated to safely store acid gases such as CO_2, nor is there adequate availability of space. Instead, again, according to Dow, 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 feasible technically but may not be economically reasonable based on the distance from the project site. See more about the economic analysis, below.

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.

The applicant contends that all of the technologies identified in Step 1 are all technically feasible.

Step 3- Rank Remaining Control Technologies

Carbon Capture and Storage offers the best control (90%) of the identified methods, and so it is ranked first. Because thermal efficiencies include work practice standards, it is difficult to discriminate the relative efficiency of the controls for ranking. The plant design limits the use of fuel choices to gaseous fuels. For this reason, the other technologies listed in Step 1 have not been ranked here, and are addressed in detail in Step 4.

BACT Step 4: Evaluate the Most Effective Controls

(a) Carbon Capture and Sequestration

CCS Economic Analysis – 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 by Dow 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 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%. See Table 3, below, for the cost analysis.

The overall cost effectiveness of a CCS system is estimated by the applicant 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 for Dow's proposed olefins project, 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 cost as well as the energy and other environmental impacts from operating a CCS system would render the proposed project unviable. Therefore, CCS is being eliminated as a potential control option in this BACT analysis for CO_2 emissions and is not considered further in this analysis

Table 3: 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 Specific 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

Table 3: Detailed CO_2 CCS Effectiveness Evaluation (con't)

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%

Cracking furnaces BACT Step 4: Evaluate the Most Effective Controls (con't)

(b) Energy and Thermal Efficient Design

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. 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.

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 **-** 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 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 94% 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 94% thermal efficiency will result in a stack design temperature of 290°F or less. The benchmarking data presented below in Tables 4, 5, and 6 will show that the selected design will be thermally efficient.

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 carbon monoxide and 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.

Decoking related maintenance- Dow has designed their furnaces such that decoking operations are vented to the furnace firebox and so there are no decoking emissions directly to atmosphere. 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. GHG emissions are produced in the process of decoking, consisting of CO_2 that is produced from combustion of the coke build up on the coils. Since these emissions are routed to the fuel header and not vented to atmosphere, there are no CO_2e emissions from this operation; however, an energy efficient design dictates that coking be kept to a minimum. Dow decoking cycles are approximately 50 days apart through good design and operations.

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.

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. 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 the number of decoking cycles that must be undertaken.

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 of the permit application dated September 19, 2013 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 process experience gives Dow the experience to understand, evaluate, and propose the best available technology design, and it also provides good data for internal benchmarking.

Table 4 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 5 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 6 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 lbs GHG emissions per lb of ethylene of 1.1 lb/lb and an annual GHG emission rate of 1.1 ton/ton. 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.

538,343 lb/hr CO2e ÷ 490,000 lb/hr ethylene maximum = 1.1 lb CO_2e / lb ethylene
2,357,946 tpy CO2e ÷ 2,102,100 tpy ethylene maximum = 1.1 ton CO_2e / ton ethylene

Table 4: Ethylene Plant Design 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 5: Design Cracking Furnace Design 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 6: Cracking Furnace Design 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

Cracking furnaces BACT Step 4: Evaluate the Most Effective Controls (con't)

(c) 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 used as fuel 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.

High purity hydrogen is vital to the oil refining business, being 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 gaseous fuels only, including natural gas and 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 is not a viable option.

BACT Step 5: Select BACT

A summary of the selected BACT for Dow is listed in Table 7. For comparison, a listing of recently permitted facilities is also provided in Table 7. Each facility manufactures ethylene and is required to use good combustion practices and energy efficient designs. This is where the similarity ends. There are significant differences in the design and operations of the facilities making fair comparisons difficult. For example, Williams is utilizing electric drive compressors and only ethane as a feedstock which will require less energy consumption, while Dow will use steam driven compressors using steam produced by the plant, and also uses primarily ethane as feedstock, but also propane in a subset of the furnaces. As a further example, The ExxonMobil furnaces will be equipped with heat recovery steam generators (HRSGs) and will have an exhaust temperature of 340^{o}F or less during ethylene production. This value is within the range permitted at similar facilities. The minimum estimated furnace efficiency, for ExxonMobil's furnaces, during on-line operation is 92% based on a 2% casing heat loss and 340 ^{o}F maximum stack temperature. The Dow facility proposed to be authorized here does not employ heat recovery steam generators and will have a normal design operations efficiency of at least 94%.

Comparing stack exit temperature across sources is also complex, as furnace exit temperature varies based on age of furnace, time since decoking, feed to be cracked, and furnace fuel. In the case of cracking ethane in the proposed Dow furnace fired with process offgas, stack temperature is expected to rise 3°F (268°F to 271°F) from start of run (immediately after a decoke) to the end of run (immediately prior to next decoke cycle). The temperature would also rise 3°F when firing natural gas rather than process gas as the fuel by end of run, but the stack exit temperature would vary from 286°F to 289°F, a temperature fully 18°F higher when firing natural gas rather than process gas.

The following specific BACT practices are proposed for each furnace:

Mass emissions of CO_2, CH_4 and N_2O will be limited as will CO_2e emissions, as shown in Table 2 (page 9, above), to a total of 2,299,697 CO_2e tons per year by implementing the various BACT elements listed here:

Energy Efficient Design - Continuously monitor the steam cracking furnaces' exhaust stack temperature and control to a maximum stack exit temperature of ≤330 ^{o}F hourly average basis, not including periods of startup, shutdown, and decoking. Furnace efficiency ≥92% under normal operations.

Low Carbon Fuels – Pipeline quality natural gas and a blended fuel gas will be utilized. A maximum fuel carbon content of 0.72lb carbon/lb fuel will be maintained. Fuel firing limited to (ethane cracking) ≤598 mmBtu/hr and ≤537 mmBtu/ hr12-month rolling average and for propane cracking: ≤599 mmBtu/hr and ≤583 mmBtu/hr 12-month rolling average.

Good Operating and Maintenance Practices – The use of good combustion practices includes periodic combustion tune-ups and maintaining the recommended combustion air and fuel ranges of the equipment as specified by its design, with the assistance of oxygen trim control. Continuously monitored furnance O_2 and CO. Stack CO concentration limited to 50 ppmvd @ 3% O_2 hourly and 20 ppmvd @3% O_2 annual average. Excess oxygen at ≤3.2% on a 12-month rolling average.

Table 7. Comparison of Recently permitted ethylene cracking furnace BACT limitations	
Company / Location/Permit Number/Year Issued/number furnaces/nominal production	**Comparative Partial BACT Emission Limit / Requirements[1,2]**
Dow Chemical Company Light Hydrocarbon 9 Freeport, TX PSD-TX-1328-GHG Proposed 2014 8 furnaces (5 ethane, 3ethane or propane) 1.5 mmtpy	• Ethane or propane feedstock cracking. • Average hourly heat input (HHV) ≤ 598 mmBtu/hr & ≤537 mmBtu/hr 12-month rolling when cracking ethane, and ≤ 599 mmBtu/hr & ≤583 mmBtu/hr 12-month rolling cracking propane. • Avg CO (@3% O_2):≤50 ppmvd/hr & ≤20 ppmvd/h 12-month rolling average. • Avg flue gas exit temperature ≤ 330° F hourly average • ≥ 92% normal operations (LHV) thermal efficiency. • Avg ratio of CO2e/ethylene: ≤ 1.1lb/lb hourly and annually • Firing methane or process offgas • Decoking emissions routed to furnace firebox. • Total annual CO_2e: 2,299,679 tons for 8 furnaces only
ExxonMobil Chemica l Co Baytown Olefins Plant Baytown, TX PSD-102982-GHG 2013 8 furnaces 2 mm metric tons/yr	• Ethane feedstock cracking. • Avg heat input (HHV) ≤ 515 mmBtu/hr firing methane or process offgas • Avg CO (@3% O_2): ≤50 ppmvd 365 day rolling hourly average • Avg flue gas exit temperature ≤ 340° F 365 day rolling hourly average • Decoking emissions vented to atmosphere • Total annual CO_2e for8 furnaces, decoking, and duct burners: 1,387,797 tons (987,968 furnaces + 2120 decoking + 397,709 duct burners)
Chevron Phillips Chemical Company, Cedar Bayou Plant Baytown, TX PSD-TX-748-GHG 2013 8 furnaces 1.5 mm metric tons	• Ethane feedstock cracking. • Avg heat input (HHV) ≤ 500 mmBtu/hr firing methane or process offgas • Avg CO (@3% O_2): parameter not set • Avg flue gas exit temperature ≤ 350° F 12-month rolling average • Decoking emissions vented to atmosphere • Total annual CO_2e for 8 furnaces & boiler: 1,579,000 tons (1,451,510 furnaces + 127,490 boiler + 2120 decoking)
BASF FINA Petrochemicals LP, NAFTA Region Olefins Complex Port Arthur, TX PSD-TX-903-GHG 2012 1 furnace 0.210 mm tpy	• Ethane, propane, naptha feedstock cracking. • Avg heat input (HHV) ≤ 491mmBtu/hr firing methane or process offgas • Avg CO (@3% O_2): parameter not set • Avg flue gas exit temperature ≤ 309° F /hr and 309°F 12-month rolling average • Decoking emissions vented to atmosphere • Total annual CO_2e for 1 furnace, 2boilers,decoking, and 2 gas turbine duct burners: 915,362 tons (256914 furnaces + 421,399 boilers + 571 decoking + 236,478 tons duct burners)
Williams Olefins LLC, Geismar Ethylene Plant Geismar, LA PSD-LA-759 2012 2 furnaces 0.275 mmtpy	• Ethane feedstock only • Avg heat input (HHV) ≤ 182/mmBtu/hr • Avg CO (@3% O_2): parameter not set • Avg flue gas exit temperature : parameter not set • Firing low carbon (25% hydrogen) process offgas • Decoking emissions vented to atmosphere • Total annual CO_2e for 2 furnaces: 182,265 tons • Cracking heaters to meet a thermal efficiency of 92.5%
INEOS Olefins & Polymers U.S.A., Chocolate Bayou Plant Alvin, TX PSD-TX-97769-GHG 2012 1 furnace 0.255 mmtpy	• Ethane feedstock cracking. • Avg heat input (HHV) ≤ 495mmBtu/hr firing methane or process offgas • Avg CO (@3% O_2): parameter not set • Avg flue gas exit temperature ≤ 340° F /hr • Decoking emissions vented to atmosphere • Total annual CO_2e for 1 furnace and decoking,: 216,65 tons (216,567 furnace + 87 decoking)

[1] Due to the variation in BACT elements, this table lists only a subset of parameters for all the listed sources. See the individual permits for an entire listing of the BACT and related requirements.
[2] All facilities are required to have energy efficient designs and use good combustion and operation and maintenance practices. Annual limitations 12-month rolling basis.

Demonstrating compliance with the BACT limitations.

In addition to meeting the quantified emission limits per furnace as listed above, EPA is proposing that Dow will demonstrate compliance with energy efficient operations by continuously monitoring the exhaust stack temperature of each furnace. The maximum stack exit temperature of 330 ^{o}F on a 365-day, rolling average basis will be calculated daily for each furnace.

Dow will demonstrate compliance with the CO_2e emission limit for the furnaces using the site specific fuel analysis for blended fuel gas utilizing an on-line gas composition analyzer and the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:

CO_2= Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel= Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using properly calibrated fuel flow meters.
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at §98.33(a)(2)(ii).
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at §98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2, site specific analysis of blended fuel gas, and the actual heat input (HHV). To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potential (GWP) found in Table A-1 of Subpart A of 40 CFR Part 98 (78 FR 71904) for each pollutant. The relevant GWP values as of the date of this public notice include: CO_2 =1; CH_4 = 25; N_2O = 298. Records of the calculations would be required to be kept to demonstrate compliance with the CO_2e emission limit on a 12-month average, rolling monthly.

An initial stack test demonstration will be required for CO_2 emissions from at least four of the eight emission units to verify that the CO_2e limit will be met. The stack test will also monitor the exhaust stack temperature and other parameters to ensure compliance with the BACT limits and workpractices.

B. BACT Evaluation for the Low Pressure (EPN OC2F597) and Pressure Assist Flares (EPN OC2F5961).

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 Highly Reactive Volatile Organic Compound regulations under 30 TAC Chapter 115 Subchapter H and Federal 40 CFR 60.18 requirements.

FLARES

BACT 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:

- Good plant design to minimize flaring
- Use of low-carbon assist gas
- Good flare design and operation
- Carbon Capture and Storage (CCS) as an add-on control.
- Flare Gas Recovery

These various strategies are described here.

Good plant design to minimize flaring - The current plant design incorporates minimum-flaring attributes such as recovery of low flow vent streams and off-spec recycle to minimize material that would otherwise be routed to the flare. It is inherent in Dow's plant design to re-use as much of the hydrocarbons as possible within the plant that would otherwise be routed to a flare. The only routine materials that will go to the flare are vent streams that cannot be recycled to the process for safety or other technical reasons. These streams include compressor seal vents and minor leaks from relief valves which are variable and unpredictable in flow and composition.

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.

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.

Carbon Capture and Storage (CCS) - 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.

Flare Gas Recovery (FGR) - FGR would be sized to recover the continuous expected vent streams to the flare not currently recovered and recycled internally, such as small leakage rates across compressor seals and minor leaks from closed vent control and pressure relief valves.

BACT Step 2- Eliminate Technically Infeasible Options

Good Plant Design to Minimize Flaring - Good plant design that recovers and recycles materials to minimize flaring is considered technically feasible.

Low-Carbon Assist Gas - Use of low-carbon assist gas is considered technically feasible.

Good Flare Design and Operation - Use of good flare design and operation is considered technically feasible.

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.

Flare Gas Recovery - FGR is used in refineries; it is not commonly used in olefins production. There is a significant process risk associated with recovering and recycling the vents from compressor seals, emergency pressure relief valves, pressure vent control valves, and purge nitrogen in that these systems are in place to manage maintenance and episodic events safely. Waste gases routed to the flare from these sources are not suited for recovery into a fuel gas system because they can contain maintenance, startup, shutdown, and emergency relief streams that vary greatly in composition and flow. Routing these streams to the fuel system can impact the overall stability of the entire process unit. Operation of these cracking furnaces is significantly more sensitive to changes in fuel quality than some processes like boilers or heat recovery units. Dow believes installing an FGR system for these vents is technically infeasible, however because FGR systems are existing technology and have been installed in certain petrochemical applications this technology will be included for further evaluation.

BACT Step 3- Rank According to Effectiveness

Use of good plant design to minimize flaring, low-carbon assist gas, good flare design and operation, and flare gas recovery are being proposed for this project. These techniques are ranked as follows:

1. **Good Plant Design to Minimize Flaring** - Good plant design to minimize flaring is ranked first. This technique is a source reduction approach as various routine, stable vent streams are collected and routed back to the process for recovery. This the most effective manner in which to inherently recover valuable product from the plant vent system as well as minimize the vents that are flared. Implementation of this minimum-flaring attribute significantly reduces the quantity of materials that are flared on a routine basis.
2. **Low-carbon assist gas –** the low carbon assist gas is natural gas, which is primarily methane.
3. **Good flare design and operation -** This attribute does not involve extensive capital cost or annual operating costs; examples of good flare design and operation include pilot flare monitoring, control of flare exit velocity, and maintaining a minimum heating value for the flared waste stream.
4. **FGR –** FGR is ranked last as it will have minimal impact on overall GHG emissions from the project, as will be shown in Step 4, below.

BACT Step 4 – Evaluate the Most Effective Controls

Use of good plant design to minimize flaring, 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.

While Dow asserts that an FGR system is not technically feasible, at the request of Region 6, they completed an economic feasibility analysis, which can be seen in Table 8, below. Dow has developed an estimate based on design criteria for the proposed LHC-9 project as actual vent flows and compositions are not available. The FGR cost estimate is based on a potential reduction of 8,812 tons/yr of CO_2 (≈1.2% of the total GHG emissions) that would be generated when flaring the material in lieu of recovering and using as a furnace fuel. Dow's estimated cost per ton of CO_2e reduced is $117/ton, which EPA believes is credible. This estimated cost, as well as the projected energy required to power the FGR compressors, and the relatively small amount of GHG that are reduced by the FGR system, supports rejection of this technology under Step 4.

Table 8: Flare Gas Recovery System Unit Cost Analysis

1.	**Direct Costs (DC)**	**Cost $**	**Cost Basis**
A.	Primary control device & ancillary equipment Cost (A)	$3,871,000	Estimated Cost= A
	Instrumentation	$193,550	0.05 A
	Sales Tax	$270,970	0.07 A
	Freight	$193,550	0.05 A
B.	Direct Installation Costs		Cost Factors from *Aspen ICARUS*
	Foundation and Support	$181,163	4% TDC
	Handling & Erection	$45,291	1% TDC
	Electrical	$90,581	2% TDC
	Piping	$905,814	20% TDC
	Insulation	$45,291	1% TDC
	Painting	$158517	3.5% TDC
	Total Direct Costs	$1,426,657	
C.	Site Prep	$50,000	
D.	Buildings	$0	
E.	**Total**	**$6,005,727**	
II.	**Indirect Costs (Installation, IC)**		
A.	Final Engineering Design	$997,000	10% TDC
B.	Construction Expense, including permits, insurance, termporary facilities, and clan-up	$452,907	10% Purchased Equipment
C.	Contractor's fee and overhead	$452,907	10% Purchased Equipment
D.	Startup	$45.291	1% Purchased Equipment
E.	Performance Tests	$45,291	1% Purchased Equipment
F.	Contingency	$1,996,000	20% TCI
G.	**Total Indirect Costs**	**$3,989,122**	
III.	**TOTAL CAPITAL INVESTMENT (TCI=DC+IC)**		
A.	Sum of Total Direct and Indirect Costs	$9,995,122	
B.	Retrofit Factor	$0	2% to 50% for retrofits on existing sources
C.	ADJUSTED TOTAL CAPITAL INVESTMENT	$9,995,122	
ANNUAL OPERATING COSTS (AOC)			
I.	**DIRECT ANNUAL COSTS (DAC)**		
A.	Labor		
	Operator (1 hr/shift)	$29,751	$27.17
	Supervisory	$4,463	%15% of Operator cost
	Maintenance	$67,936	1.5% of purchased equipment
B.	Maintenance Materials	$0	set to zero, normally= mtc labor
C.	Operational Materials		
	Chemicals	$0	
	Other (Carbon, Catalyst, etc)		
	Value of any recovered material for sale or credit		
D.	Utilities		
	Natural Gas	-$882,701	-28.79 mmBtu/hr @ $5/mmBtu, 70% on-stream factor
	Other Fuel		
	Electricity	$173,448	30 kw @ $0.06/kwh
	Other	$0	
E.	TOTAL DIRECT ANNUAL COSTS	-$607,104	

Table 8. Flare Gas Recovery System Unit Cost Analysis (Continued from previous page)			
II.	**INDIRECT ANNUAL COSTS (IAC)**		
A.	Capital Recovery	$1,174,203	Annual cost to recover TCI
	Capital recovery factor	0.1175	Based on APR & term below
	Annual Interest Rate	0.100	
	Investment Term (yr)	20	
B.	Labor Overhead	$61,290	60% of total labor and mtc
C.	Administration, Taxes, and Insurance	$399,805	4% of TCI
D.	TOTAL INDIRECT ANNUAL COSTS	$1,635,138	
III.	**TOTAL ANNUAL OPERATING COSTS**	**$1,028,035**	**AOC=DAC+IAC**
IV.	**POLLUTION CONTROL EFFECTIVENESS**		
A.	Typical Emission Rate w/o FGR	44,097	ton/yr. This is the total CO_2e emissions from the pressure assisted ground flare
B.	Emission Rate with FGR	35,285	ton/yr. This includes emissions from MSS, intermittent streams, flare pilots, and 30% of the streams intended for FGR
C.	Total Emissions Reduction	8,812	ton/yr. Diff between IV.A-IV.B
V.	**EMISSION CONTROL COST EFFECTIVENESS**		
	Overall Cost Effectiveness	$117	($/ton)
	Fraction of Project GHG emissions controlled	0.4%	8,812 tpy CO_2e /2,357,946 tpy CO_2e

Step 5 – Select BACT

The following specific BACT practices are proposed for each flare:

Mass emissions of CO_2, CH_4 and N_2O will be limited as will CO_2e emissions, as shown in Table 2 above, to a total of 14,046 tpy CO_2e (Low Pressure Flare) and 44,089 tpy CO_2e (Pressure Assist Flare) by implementing the various BACT elements listed here:

Low Carbon Fuels – Pipeline quality natural gas will be used for the flare pilots. In addition, continuous monitoring of flow composition and volume will be in place so that emissions can be calculated appropriately.

Good Plant Design and Operating and Maintenance Practices – The use of good combustion and operating practices for flares includes continuous pilot monitoring, continuous flows and composition of waste gas and continuous monitoring of the flare operating parameters as per 40 CFR §60.18 and site specific flare parameters to be determined by the EPA for the high pressure flare during high pressure events.

Demonstrating compliance with the BACT limitations.

In addition to meeting the quantified emission limits per furnace as listed above, EPA is proposing that Dow will demonstrate compliance with the permit limitations by using the data collected and calculate emissions following the method in 40 CFR 98 Subpart X for flares.

The equation for estimating CO_2 emissions as specified in 40 CFR 98.253(b)(1)(ii)(A) is as follows:

$$CO_2 = DRE \times 0.001 \times \left(\sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) * 1.102311$$

Where:

CO_2 =	Annual CO_2 emissions for a specific fuel type (short tons/year).
DRE =	Assumed combustion efficiency of the flare.
0.001=	Unit conversion factor (metric tons per kilogram, mt/kg).
n =	Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p =	Measurement period index.
44 =	Molecular weight of CO_2 (kg/kg-mole).
12 =	Atomic weight of C (kg/kg-mole).
$(Flare)_p$ =	Volume of flare gas combusted during the measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term "$(MW)_p$/MVC" with "1".
$(MW)_p$ =	Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
MVC =	Molar volume conversion factor (849.5 scf/kg-mole).
$(CC)_p$ =	Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
1.102311 =	Conversion of metric tons to short tons.

The GHG mass emission limits in TPY associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98 Subpart C, Table C-2 using the GWPs of 40 CFR 98 as published on 11/29/2013 in (78 FR 71904), site specific analysis of waste gas, and the actual heat input (HHV).

C. BACT Evaluation for the Thermal Oxidizer (TOX, EPN: OC2TOX)

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. During times when the TOX is unavailable, the waste gas streams will be routed to the low pressure flare. Waste gas flowing to the TOX will be continuously monitored, as will be waste gas composition and quantity.

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. 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)

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.

Good Combustion Practices and Maintenance- Good combustion practices and maintenance include operation of the thermal oxidizer with adequate but not excessive 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 TOX manufacturer.

Good combustion practices include monitoring of firebox temperature and % oxygen. Destruction efficiency of the waste gas stream (which can include methane) will be assured my maintaining a firebox temperature above 1400°F at all time (when in operation) and assuring that adequate but not excessive % O_2 is present in the firebox..

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.

Step 2 - Eliminate Technically Infeasible Options

Low-Carbon Assist Gas- Use of low-carbon assist gas is considered technically feasible.

Good combustion practices and maintenance- is considered technically feasible.

CCS- Carbon capture and storage has been discussed and eliminated in the earlier discussion on furnace GHG emissions controls, and will not be repeated in this section.

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.

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.

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 TOX.

Low Carbon Fuels – Pipeline quality natural gas and a blended fuel gas will be utilized. A maximum fuel carbon content of 0.72lb carbon/lb fuel will be maintained.

Good Operating and Maintenance Practices – The use of good combustion practices includes periodic combustion tune-ups and maintaining the recommended combustion air and fuel ranges of the equipment as specified by its design, with the assistance of oxygen trim control. Continuously monitored furnance temperature and % O_2.

Demonstrating compliance with the BACT limitations. Dow will demonstrate compliance with the CO_2e emission limit for the TOX using the same methods used in the furnace emissions determination, above, that is, the site specific fuel analysis for fuel gas utilizing an on-line gas composition analyzer and the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1. The emissions from the waste stream being controlled by the TOX is also determined in the same method, except using the composition and flow of the waste gas to determine the relevant parameters. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:

CO_2=	Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel=	Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using properly calibrated fuel flow meters.
CC =	Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at §98.33(a)(2)(ii).
MW =	Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at §98.33(a)(2)(ii).
MVC =	Molar volume conversion factor at standard conditions, as defined in §98.6.
44/12 =	Ratio of molecular weights, CO_2 to carbon.
0.001 =	Conversion of kg to metric tons.
1.102311 =	Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2, site specific analysis of gasses combusted, and the actual heat input (HHV). To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potential (GWP) found in Table A-1 of Subpart A of 40 CFR Part 98 (78 FR 71904) for each pollutant. The relevant GWP values as of the date of this public notice include: CO_2 =1; CH_4 = 25; N_2O = 298. Records of the calculations would be required to be kept to demonstrate compliance with the CO_2e emission limit on a 12-month average, rolling monthly.

An initial stack test demonstration will be required for CO_2 emissions from the TOX to assure that the destruction efficiency is met and the CO_2e emissions limitations are met. An initial stack test demonstration for CH_4 and N_2O emissions are not required because the CH_4 and N_2O emission are less than 0.01% of the total CO_2e emissions from the furnaces and are considered a *de minimis* level in comparison to the CO_2 emissions.

D. BACT Evaluation for Equipment Leak Fugitive Emissions (EPN: OC2FUG) and Cooling Tower Heat Exchanger system (EPN:OC2CT936), collectively, "Fugitives"

The proposed LHC-9 facility will include piping components with GHG fugitive emissions. In addition, the heat exchanger cooling tower system has been demonstrated to be a source of fugitive emissions, particularly in the Houston Galveston nonattainment area. It should be noted that these are very small sources of GHG and so rather than having a specific emission limit to govern the emissions, these emissions are governed by implementation of workpractice standards related to the control of fugitive VOC emission.

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, such as the waste gas lines to the thermal oxidizer and flares, and 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, and for controlling leaks from the cooling tower waters.

As is the case of emissions from the pipe components and equipment leaks above, the cooling tower is subject to Highly Reactive Volatile Organic Compound (HRVOC) control requirements found in 30 TAC Chapter 115 Subchapter C. Because process fluids to be cooled may contain methane in addition to the HRVOCs and never methane alone, this required control program will result in concurrent HRVOC and methane control.

Step 1- Identify Available Control Technologies

Piping fugitives may be controlled by various techniques, including:

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

VOC leaks from cooling towers are controlled by sampling the cooling tower waters on a regular basis to identify leaks and to then repair such leaks when they are found.

Step 2 - Eliminate Technically Infeasible Options

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.

Implementation an LDAR program- Use of instrument LDAR is considered technically feasible.

Implementation of Remote Sensing- Use of remote sensing measures is considered technically feasible.

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.

Cooling tower sampling for HRVOC- Use of cooling tower sampling is considered technically feasible since it concurrently addresses methane as well as HRVOC.

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.[5] 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. The adoption of the HRVOC testing requirements have proven effective in controlling emissions from cooling tower heat exchanger systems.

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 and cooling tower sampling program as BACT. Dow will implement TCEQ's 28 VHP LDAR program for piping components in VOC (including 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. Because cooling tower monitoring is also required of the tower at Dow by permit and by rule, the program will also assure that GHG emissions from the heat exchanger systems are effectively controlled.

[5] 73 *FedReg* 78199-78219, December 22, 2008

Step 5 – Select BACT

Dow proposes incorporate the control of GHG emissions (methane) control through the use of its existing LDAR and cooling tower control programs as workpractices that will assure the minimization of GHG from these sources.

Demonstrating compliance with the BACT limitations. Dow will demonstrate compliance with the workpractice standards of LDAR and cooling tower sampling by keeping records of both of those practices.

E. BACT Evaluation for Emergency Generators (EPNs: OC2GE1 and OC2GE2) collectively, "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 96 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.

BACT 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. 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.

BACT Step 2– Eliminate Technically Infeasible Options

Use of good combustion practices is considered technically feasible.

BACT 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.

BACT 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.

BACT Step 5– Select BACT

Dow proposes to incorporate good combustion practices discussed in Step 2 above 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.

Good Operation and Maintenance Practices – Good operation and maintenance practices for compression ignition engines include appropriate maintenance of equipment, periodic testing conducted weekly, and operating within the recommended air to fuel ratio, as specified by its design.

Using the operating and maintenance practices identified above results in a BACT limit of 34 tpy CO_2e for all engines combined. Dow will demonstrate compliance with the CO_2 emission limit using the emission factors for diesel fuel from 40 CFR Part 98 Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(ii) is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * 0.001 * 1.102311$$

Where:

CO_2 =	Annual CO_2 mass emissions from combustion of diesel fuel (short tons)
Fuel =	Annual volume of the liquid fuel combusted (gallons). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).
CC =	Annual average carbon content of the liquid fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at §98.33(a)(2)(ii).
44/12 =	Ratio of molecular weights, CO_2 to carbon.
0.001 =	Conversion of kg to metric tons.
1.102311 =	Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2.

IX. Endangered Species Act

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant, Dow Chemical Company ("Dow"), and its consultant, URS Corporation ("URS"), and adopted by EPA.

A draft BA has identified twenty-three (23) species listed as federally endangered or threatened in Brazoria County, Texas:

Federally Listed Species for Brazoria, Galveston, Harris, and Chambers County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Reptiles	
Green sea turtle	*Chelonia mydas*
Hawksbill sea turtle	*Eretmochelys imbriacata*
Kemp's ridley sea turtle	*Lepidochelys kempii*
Leatherback sea turtle	*Dermochelys coriaea*
Loggerhead sea turtle	*Caretta caretta*
Birds	
Piper plover	*Charadrius melodus*
Attwater's Greater Prairie Chicken	*Tympanuchus cupido attwateri*
Red-cockaded woodpecker	
Whooping crane	*Grus americanus*
Eskimo curlew	*Numenius borealis*
Amphibian	
Houston toad	*Bufo houstonensis*
Fish	
Smalltooth sawfish	*Pristis pectinata*
Whales	
Blue Whale	*Balaenoptera musculus*
Finback Whale	*Balaenoptera physalus*
Humpback Whale	*Megaptera novaeangliae*
Sei Whale	*Balaenoptera borealis*
Sperm Whale	*Physeter macrocephalus*
Mammals	
Louisiana Black Bear	*Ursus americanus luteolus*
Jaguarundi	*Herpailurus yagouaroundi*
Ocelot	*Leopardus pardalis*
West Indian manatee	*Trichechus manatus*
Red Wolf	*Canis rufus*
Plants	
Texas Prairie Dawn	*Hymenoxys texana*

EPA has determined that issuance of the proposed permit will have no effect on any of the twenty-two listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area. EPA's "no effect" determination for all twenty-two endangered species except the whooping crane, which has a determination of "not likely to adversely affect".

Because the proposed project is located on the far eastern edge of the Aransas-Wood Buffalo breeding, migrating, and wintering area for the whooping crane and is located within its migratory path, EPA determines that this project may affect, but is not likely to adversely affect the whooping crane. Information in the BA indicates that there is no known or potential habitat for the cranes within the action area. However, because the use of certain construction equipment poses a possible but unlikely risk of bird strikes during flyovers, Dow engaged in informal consultation with the USFWS's Southwest Region, Clear Lake Texas Ecological Services Field Office. Following discussions with USFWS, Dow was recommended to use USFWS's "Memorandum Service Guidance on the Siting, Construction, Operation, and Decommissioning of Communications Towers" for flagging or marking of permanent structures constructed as a result of this project to which Dow has committed to implement. For temporary structures such as construction cranes, Dow will consider marking any construction equipment with lighting/flags when possible. EPA determines that the implementation of these USFWS recommended measures and practices are sufficient to reduce the possibility of strikes to a level that reduces these potential effects to insignificant or discountable. EPA has requested concurrence on its determination from the USFWS's Clear Lake Field Office.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

X. National Historic Preservation Act

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on and adopted a cultural resource report prepared by URS submitted in January 2014.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be the location of the proposed construction of a new ethylene production unit on a 35-acre site within an existing chemical manufacturing complex, a wastewater line within the same complex, a 39-acre laydown yard west of the site, and a 79-mile, 200-foot wide pipeline corridor. URS conducted a desktop review for the area within a one-mile radius of the APE for the production unit, laydown yard, and wastewater line. HRA Gray and Pape, LLC ("HRA") conducted a desktop review for the area within a 0.5-mile radius of the pipeline corridor. Both desktop reviews included an archaeological background and historical records review using the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP). The URS desktop review identified four previous archaeological surveys, no known archaeological or historical resources located within one mile of the planned facility undertakings. Because the APE is located in a highly disturbed industrialized complex, it lacks the potential to contain undisturbed archeological resources, and therefore field and subsurface investigations were not conducted. The HRA desktop review identified several previous archaeological surveys, 34 previously recorded sites, 19 shipwrecks, 2 historic markers and 3 cemeteries located within 0.5 mile of the pipeline corridor, but outside the pipeline APE. However, three of the previously recorded sites were eligible or potentially eligible listing on the NR and were located within the APE. Based on the results of the field survey that included shovel testing, four new archeological resources and two historic structures were identified. All archeological resources that were either eligible or potential eligible for listing on the National Register (NR) and were determined to be inside the pipeline APE will be avoided by the use of horizontal directional drilling. The historic structures were assessed as being not eligible for listing on the NR and outside of the pipeline APE.

EPA Region 6 determines that because potential for the location of archaeological resources within the construction footprint of the facility itself is low, archaeological resources along the pipeline corridor will be avoided, no historic properties are located within the APE of the facility, and historic structures will not be impacted near the pipeline; issuance of the permit to Dow will not affect properties eligible or potentially eligible for listing on the National Register.

On February 14, 2014, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XI Magnuson-Stevens Act

The 1996 Essential Fish Habitat (EFH) amendments to the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act) set forth a mandate for NOAA's National Marine Fisheries Service (NMFS), regional fishery management councils (FMC), and other federal agencies to identify and protect important marine and anadromous fish habitat.

To meet the requirements of the Magnuson-Stevens Act, EPA is relying on an EFH Assessment prepared by the URS on behalf of Dow and reviewed and adopted by EPA.

The facility and associated pipeline is adjacent to tidally influenced portions of the Brazos River Tidal, Dow Barge Canal, Chocolate Bayou, Highland Bayou, Dickinson Bayou, Cedar Bayou and the San Jacinto River. These tidally influenced portions have been identified as potential habitats of postlarval, juvenile, subadult or adult stages of red drum (*Sciaenops ocellatus*), shrimp (4 species), and reef fish (43 species). The EFH information was obtained from the NMFS's website (http://www.habitat.noaa.gov/protection/efh/efhmapper/index.html).

Furthermore, these tidally influenced areas have also been identified by NMFS to contain EFH for neonate of the bull shark (Carcharhinus leucas) and scalloped hammerhead shark (Sphyrna lewini); neonate and juvenile of the bonnet head shark (Sphyrna tiburo) and blacktip shark (Carcharhinus limbatus); and neonate and adult of the Atlantic sharpnose shark (Rhizoprionodon terraenovae),.

Based on the information provided in the EFH Assessment, EPA concludes that the proposed PSD permit allowing Dow construction of a new ethylene production unit within the existing Dow Freeport facility will have no adverse impacts on listed marine and fish habitats. The assessment's analysis, which is consistent with the analysis used in the BA discussed above, shows the project's construction and operation will have no adverse effect on EFH.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final essential fish habitat report can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XII. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this EO, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal PSD permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG controlled by what we have determined is BACT for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no NAAQS for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are 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 [PSD and Title V Permitting Guidance for GHGS at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XIII. Conclusion and Proposed Action

Based on the information supplied by Dow, our review of the analyses contained the TCEQ NSR Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue Dow a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.