Occidental Chemical Corporation **OxyChem.**
A subsidiary of Occidental Petroleum Corporation

P. O. Box CC, Ingleside, Texas 78362-0710
4133 Hwy 361, Gregory, Texas 78359
Phone 361.776-6000 Fax 361.776-6208

January 16, 2014

CERTIFIED LETTER - RETURN RECEIPT REQUESTED

Ms. Aimee Wilson
U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue
Dallas, TX 75202-2733

Re: **GHG Permit Application Update**
Occidental Chemical Corporation
Ingleside Chemical Plant
Ethylene Plant

Dear Ms. Wilson:

Occidental Chemical Corporation (OxyChem) is submitting the enclosed GHG permit application update for the new Ethylene Plant at the Ingleside Chemical Plant. This application revises and replaces the information submitted in previous applications and updates.

OxyChem is very interested in proceeding with the timely processing of this application. If there are any questions, please do not hesitate to contact me at (361) 776-6169 or Mark.Evans@oxy.com. Thank you for your time and consideration in the matter.

Sincerely,

Mark Evans

Mark R. Evans
Environmental Manager – Projects

Enclosures

Cc: Mr. Tom Lawshae, Air Permits Division, TCEQ, Austin, w/enclosures

THE U.S. ENVIRONMENTAL PROTECTION AGENCY FEDERAL PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION
Update

OCCIDENTAL CHEMICAL CORPORATION
INGLESIDE CHEMICAL PLANT, SAN PATRICIO COUNTY
TCEQ ACCOUNT ID NO. SD-0092-F
TCEQ CUSTOMER NO. 600125256
TCEQ REGULATED ENTITY NO. 100211176

ETHYLENE PLANT

January 2014

Submitted by:

Mark R. Evans
Environmental Manager
Occidental Chemical Corporation

Occidental Chemical Corporation
January 2014

TABLE OF CONTENTS

Occidental Chemical Corporation
January 2014

INTRODUCTION

Occidental Chemical Corporation (OxyChem) is proposing to construct and operate a new 1.5 billion pound-per-year Ethylene Plant at its existing site near Ingleside, Texas on land immediately adjacent to the existing Vinyl Chloride Monomer (VCM) Plant. The new Ethylene Plant will receive ethane feed from an OxyChem planned Natural Gas Liquids (NGL) Fractionation Plant to be constructed on adjacent property or by pipeline. The Ethylene Plant will produce market grade ethylene which will be transported by pipeline as feed material to the existing VCM Plant or to other markets.

Ingleside, Texas is in San Patricio County which is an attainment area for all criteria pollutants; therefore, the site is not subject to federal Nonattainment Review regulations. Construction of this Ethylene Plant constitutes a major modification with respect to federal Prevention of Significant Deterioration (PSD) regulations for the following pollutants: volatile organic compounds, nitrogen oxides, carbon monoxide, particulate matter, particulate matter less than 10 microns, particulate matter less than 2.5 microns and greenhouse gases (GHGs). All of these PSD pollutants except for GHG are addressed in a separate application submitted to the TCEQ in December 2012. This application is only intended to authorize the GHG emissions from the proposed facilities associated with the Ethylene Plant.

This document is an updated application to the initial GHG permit application dated December 21, 2012 previously submitted to the US EPA Region 6 for the Ethylene Plant project. This application update incorporates all previous supplements and supersedes all previous submittals. A general application and GHG PSD applicability forms for the proposed Ethylene Plant are provided in Appendix A, General Application and PSD Applicability Forms.

Occidental Chemical Corporation
January 2014

SUMMARY OF CHANGES

This updated permit application is being provided to include revisions and clarifications that were requested by EPA (see Update Nos. 1-11), provide updated emissions estimates, and to provide additional information based on public comments for similar projects (see Update Nos. 12-14). All updates since the December 21, 2012, initial application are listed below:

Update #1	**Addition of a hydrogen vent emission point**	**Ethylene Plant Process Description - Pg 3 and Appendix C - GHG Emissions Summary**
Update #2	**Revisions that identify a five cell cooling tower rather than a six cell cooling tower**	**Ethylene Plant Process Description - Pg 4 and Appendix C - GHG Emissions Summary**
Update #3	**Removal of low pressure flare from the design**	**Ethylene Plant Process Description - Pg 4 and Appendix C - GHG Emissions Summary**
Update #4	**Specific Energy Consumption values for furnaces**	**Proposed Greenhouse Gas (GHG) Emissions - Page 6**
Update #5	**Value for tons CO_2/Ton Ethylene produced for furnaces**	**Proposed Greenhouse Gas (GHG) Emissions - Page 6**
Update #6	**Updated map that includes the new 20.5 acres changing ownership to DuPont**	**Appendix B - USGS Map**
Update #7	**Updated plot plan**	**Appendix B – Emission Point Source Plot Plan**
Update #8	**Updated Process Flow Diagram**	**Appendix B - Process Flow Diagrams**
Update #9	**Use of high hydrogen fuel instead of worst case natural gas firing CO_2 emissions for proposed furnace permit limits**	**Appendix C - GHG Emissions Summary**
Update #10	**GHG fugitive estimates revisions due to plot plan adjustments, total GHG fugitives did not change**	**Appendix C - Fugitive Emissions Calculations - Proposed GHG Emisions**

Update #11	**Addition of Average Cost Effectiveness calculations**	**Appendix D – Pages 3, 4, 8, and 9 of Best Available Control Technology**
Update #12	**Updated total ethylene production from 1.2 to 1.5 billion pounds per year based on maximum design capacity of the furnaces.**	**Introduction – Page 1 and Proposed GHG Emissions**
Update #13	**Updated CCS Average Costs Effectiveness calculations and design basis.**	**Appendix D – Best Available Control Technology**
Update #14	**Updated application language to provided clarification and further project details**	**Ethylene Plant Process Description, Proposed GHG Emissions**

ETHYLENE PLANT PROCESS DESCRIPTION

The ethane feed to the Ethylene Plant is combined with recycle ethane from the ethylene fractionator and superheated with water before being sent to the cracking furnaces. The cracking furnaces will be equipped with selective catalytic reduction (SCR) technology for NO_x control. Pre-heated Ethane using recovered heat is fed to five cracking furnaces to be further heated to cracking temperature. The ethane cracking furnace design includes energy efficiencies such as the use of heat exchangers on the process and flue gas outlet of the cracking furnaces to recover waste heat. Hydrogen rich vent gas is used for furnace fuel which is beneficial in reducing CO_2 emissions.

To minimize coke formation in the cracking furnace tubes, a sulfide material is added continuously to the ethane feed stream at low part-per-million (ppm) levels. Two chemicals may be used for this purpose, dimethyl disulfide (DMDS) or dimethyl sulfide (DMS). The sulfide chemical is stored in a pressurized tank and truck off-loading of the material is accomplished using vapor balancing with the delivery truck.

The effluent from cracking furnaces is used to recover heat by producing high pressure steam and preheating ethane in transfer line exchangers (TLEs) before being quenched in the quench tower. The cracked gas from the TLEs is cooled and partially condensed by direct countercurrent contact with recirculating water in the quench tower. The condensed gasoline and dilution steam, along with quench water, are separated in the bottom section of the quench tower and the non-condensable gas exits the top of the quench tower.

The quench tower overhead vapors (non-condensable gas) are sent to the first stage of the steam driven charge gas compressor where the vapors are compressed in a three stage centrifugal compressor. Acid gases are removed from the charge gas in the third stage compressor discharge. The acid gas removal consists of a three stage caustic wash tower. Charge gas from the caustic wash tower overhead is chilled in the dryer feed chiller system. Charge gas from the dryer feed chiller system overhead is dried in a molecular sieve drying system.

The vapor from the charge gas dryer is chilled before entering the front-end de-ethanizer. The de-ethanizer tower produces a vapor overhead product with primarily ethane, ethylene and lighter content and a bottoms product that is stripped of ethane and lighter components. Acetylene is removed from the de-ethanizer overhead by selective hydrogenation to ethylene and ethane. The de-ethanizer overhead product is then chilled and sent to the de-methanizer.

The overhead of the de-methanizer consists of methane and hydrogen. This hydrogen-rich vapor from the de-methanizer is processed to separate hydrogen for use in the hydrogenation reactors and the balance is used as fuel gas. During brief periods when more fuel gas is produced than is required by the furnaces, hydrogen is vented through a hydrogen vent to remove fuel gas from the system. De-methanizer bottoms are fed to the ethylene fractionator. The ethylene fractionator overhead vapor is condensed as ethylene product that is sent out by pipeline or to the adjacent VCM plant. The ethylene fractionator bottoms are predominantly ethane and this stream is returned to the cracking furnace feed.

The de-ethanizer bottoms product is sent to the de-butanizer to separate the C3s and C4s from the C5+ gasoline. The debutanizer bottoms product is sent to C5 gasoline storage. The de-butanizer overhead product is hydrotreated in the hydrogenation reactor to convert diolefins and olefins into normal propane and butane. The propane/butane mix stream from the hydrogenation reactor is returned to the NGL Fractionation Plant as feed or shipped off site as product.

One of the byproducts of the Ethylene Plant is a stream called pyrolysis gasoline. This material is sold to petroleum refineries as a gasoline blend stock. The pyrolysis gasoline will be loaded into trucks for transportation to the refinery customers. The vents from loading these trucks are routed to the cracker thermal oxidizers for VOC control.

A propylene refrigeration system, which utilizes a steam turbine-driven centrifugal compressor, provides refrigeration at four levels of temperature. A binary refrigerant system uses methane and ethylene to provide the coldest level of refrigeration in the plant for cooling and condensing process streams at three additional levels.

Spent caustic from the caustic tower is treated in a wet air oxidizer system to oxidize sulfides and other chemical oxidation demand before being discharged to the wastewater treatment plant.

A five-cell cooling tower will be used to remove the heat from the process by thermal exchange.

A unique aspect of this project is the use of two thermal oxidizers to combust low pressure discharges of vent gases from process equipment and storage vessels. The original project design routed these vents to the two thermal oxidizers and a low pressure flare, as indicated in the December 2012 initial application. The project design has been modified and the low pressure flare has been eliminated. These vents will be combusted in the thermal oxidizer system to provide higher emissions control and generate steam from the waste heat. Combusting these vents in a flare would result in lower VOC emissions control and does not provide heat recovery. The two thermal oxidizers are designed to destroy and remove organic materials from the collected vent gases with an efficiency of at least 99.9%. They are supplied with natural gas to ensure complete combustion with minimum production of carbon monoxide.

In addition to the thermal oxidizers which provide the primary emissions control for vents, a high pressure flare system provides a means to collect and combust hydrocarbon process streams that have relieved or been drained to the flare headers at a rate or pressure greater than the thermal oxidizers can control. The emergency relief collection and transfer systems discharge to a multi-point low profile, high pressure ground flare with a staged burner control system. A heat radiation shielding fence will minimize the radiation to the acceptable level outside the fence and avoid production of a visible flame. Numerous pilots, supplied with natural gas, are provided to ensure that any emergency relief of process streams will be combusted.

Process wastewaters, contaminated storm water, surface wash down and other wastewaters are collected in process area sumps which pump to wastewater storage tanks. The wastewater storage tank is vented to the thermal oxidizers. Wastewater from the wastewater storage tank is sent to the wastewater steam stripper to remove volatile organic compounds prior to treatment in an activated sludge treatment system within the existing VCM Plant.

A summary of storage tanks is provided as follows:

1) Pressure tanks: 90,000-gal propylene tank; two 650,000-gal C3/C4 tanks; 10,000-gal anhydrous ammonia tank; 10,000-gal DMS/DMDS tank
2) Low pressure tanks venting to the oxidizers: three 1,100,000-gal contaminated water tanks; two 135,000-gal pyrolysis gasoline tanks; 45,000-gal heavy oil tank; 105,000-gal collected oil tank; 18,000-gal wash oil tank; two 82,620-gal spent caustic tanks
3) Atmospheric tanks: 10,000-gal methanol tank (PBR 106.473); 10,000-gal sulfuric acid tank (PBR 106.472)

Process flow diagrams for the new Ethylene Plant are provided in Appendix B. This appendix includes a plot plan, area map and other documents requested in Section VII of the Form PI-1.

PROPOSED GREENHOUSE GAS (GHG) EMISSIONS

Emission calculations for maximum hourly and annual rates are provided in Appendix C, Emission Calculations. This emissions data includes the basis for the calculations, the emission factors, sources of the factors, pollutant specific estimates and calculation methods.

The GHG emissions calculated for these sources include the following: carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O). The proposed emissions in Appendix C include the use of the appropriate global warming potential factors to express these GHG emissions as carbon dioxide equivalents (CO_2e).

The new sources proposed for the Ethylene Plant are identified as follows: five cracking furnaces, two thermal oxidizers, a high pressure ground flare, an emergency generator engine, a cooling tower, a hydrogen vent, and fugitive sources identified for six operating areas. In addition, intermittent emissions are expected from the C3/C4 hydrogenation regeneration vent. GHG emissions are expected from all of these sources except for two of the six fugitive areas.

The proposed project will not affect emissions from existing equipment except for additional firing of the cogeneration units (EPNs: CG-1 and CG-2, Permit Nos. 35335 and PSD-TX-880) during startup of the Ethylene Plant. These cogeneration units are not being modified and their increased fuel firing will not result in exceedances of previously authorized levels. For the purpose of the current permit review, these cogeneration units are considered by the EPA to be affected sources that should be used to determine the applicability of federal PSD permitting.

Appendix C includes estimated emission increases for all of the ethylene production facilities, including the cogeneration units.

EPNs CR-1 through CR-5; Ethane Cracking Furnaces Nos. 1 through 5

The ethane cracking furnaces for the proposed Ethylene Plant include five identical combustion units expected to fire natural gas and hydrogen-rich fuel gas at a maximum rate of 275 MMBtu/hr. Typically, four of these units will be operating while the fifth unit is being serviced or held on stand-by. However, at times, all five units may be running at full capacity. Based on the maximum proposed firing rate for five furnace operation at 12.05 x 10^6 MMBtu/yr (275 MMBtu/hr x 5 furnaces x 8760 hr/yr) and the annual ethylene production of 1.5 billion pounds per year (750,000 tons/yr), this yields a specific energy consumption value of 16.1 MMBtu/ton, which is average compared to recently permitted ethylene production facilities.

Normal operation involves natural gas and/or process-related fuel gas (high hydrogen gas) firing in the furnaces and the control of NO_x emissions using SCR. Three additional operating scenarios are described below that pertain to furnace maintenance, start-up and shutdown (MSS) activities.

During normal operations, furnaces will be operated using process generated fuel gas which is a combination of hydrogen, methane, ethane, and heavier hydrocarbons. OxyChem will use hydrogen-rich fuel gas that is not used in the facility's hydrogenation processes as the preferred fuel for the furnaces and thereby will minimize CO_2 emissions from the ethane cracking furnaces. During normal operations, the heat input to the furnace fire box is maintained to achieve the desired cracking rate. Ethane and steam are fed to the furnace tube inlets and the furnace outlet is routed to the quench tower where the process gases are cooled.

It should be noted that firing only natural gas without the process fuel gas results in higher CO_2 emissions; therefore this scenario is included in the Appendix C emission calculations for comparison purposes only. OxyChem is proposing to comply with more restrictive permit limits based on firing a blend of natural gas and hydrogen fuel.

The proposed CO_2e emissions from the cracking furnaces results in an emission rate of 0.39 ton of CO_2e per ton of ethylene produced (295,100 tons/yr $CO_2e \div 750{,}000$ tons/yr ethylene) which is favorable when compared to the CO_2e rates of recently permitted ethylene cracking furnaces.

EPNs CR-1-MSS through CR-5-MSS; Ethane Cracking Furnaces Nos. 1 through 5 - MSS Activities

The ethane cracking furnaces mentioned above have three additional scenarios that can be described as follows:

1) *Furnace Cold Start-up* - When the furnaces are starting up after a complete plant shutdown, there is no process generated fuel gas available and pipeline supplied natural gas is fired in the furnaces.

2) *Hot Steam Standby* - Hot steam standby mode of operation is established immediately after a furnace has completed a steam decoke. During hot steam standby, the furnace has steam flowing through the tubes, minimum firing rate on the firebox, and the furnace discharge is routed to the quench tower. This operation mode is maintained until the furnace is placed back in the normal operation mode.

3) *Steam Decoking* - Due to the high furnace tube temperatures during normal operations, coke deposits build up on the furnace tube walls. To maintain efficient furnace operation, this coke must be removed periodically using a steam decoking process.

   The steam decoking process is started by cutting the ethane feed to an operating furnace while leaving steam flowing through the furnace tubes, and maintaining fire box heat input at a reduced rate. The furnace discharge continues to feed forward to the quench tower until the ethane is purged from the furnace tubes.

   Once the furnace tubes are cleared of ethane, the furnace discharge is diverted from the quench tower to the furnace fire box. Other ethylene processes route this stream to the atmosphere which contributes to increased particulate and carbon monoxide emissions. By routing this stream to the fire box, the particulate material and carbon monoxide are combusted to generate heat while reducing particulate and carbon monoxide emissions. Air is added to the furnace tubes along with steam, to begin burning coke in the furnace tubes.

   The air flow is gradually increased until all of the coke is burned off. Once decoking has been completed, the air flow to the tubes is cut off, steam flow is maintained on the furnace tubes, minimum firing is maintained on the fire box and the furnace outlet is re-routed to the quench column.

The emissions from these activities were reviewed and the only possible increase in GHG emissions involves the steam decoking scenario. However, as shown in the Appendix C calculations, steam decoking GHG emissions are not greater than emissions estimated for normal operations.

EPNs CR-6 and CR-7; CR Thermal Oxidizer Nos. 1 and 2

OxyChem's original Ethylene Plant design included a low pressure elevated flare. OxyChem has redesigned the process to eliminate the low-pressure flare and recover all low pressure vents to the thermal oxidizers only. The thermal oxidizer system for the proposed facilities includes two identical combustion units that are each designed to fire pipeline natural gas and waste gas at a maximum rate of 85 MMBtu/hr. Typically, these units will both be operating and will share the load of waste gases generated by the new facilities.

Waste gases include both continuous and intermittent streams from the process and storage vessels. All non-pressurized storage tanks at the site handling VOC materials with vapor pressures greater than 0.5 psia are vented to the thermal oxidizers for control.

Also, VOC emissions resulting from pyrolysis gasoline truck loading will be handled through the oxidizers. The pressure ratings of trucks are sufficient to maintain 100% collection of displaced vapors.

Since each thermal oxidizer is capable of handling all of the waste gas from the proposed facilities, each unit will be permitted at maximum rates so that operational flexibility is maximized. The thermal oxidizers will be equipped with heat recovery boilers to recover waste heat for increased energy efficiency. These heat recovery boilers have the similar function as flare gas recovery in utilizing waste gas to generate steam. Steam generation from these units is intended to reduce the demand for steam from the existing cogeneration units.

Detailed emission calculations for the thermal oxidizers are provided in Appendix C.

EPN CR-8; CR High Pressure Flare

The high pressure ground flare is included in the emission calculations because its pilots burn natural gas. Otherwise, all gases routed to the flare will be the result of MSS events (see EPN CR-8-MSS) or upsets (emission events). Since emission events are not subject to permitting requirements, they are not addressed in this application.

EPN CR-8-MSS; CR High Pressure Flare - MSS Activities

The high pressure ground flare's emissions associated with MSS activities are included in this authorization. It should be noted that the number of events, gas input mass rates and hours per event represented in the Appendix C calculations are provided for calculation purposes only; these parameters could change, OxyChem will manage MSS activities such that the proposed annual emission rates will not be exceeded.

Detailed emission calculations for high pressure flare MSS activities are provided in Appendix C.

EPN CR-9; CR Emergency Generator Diesel Engine

The diesel-fired emergency generator engine is included in the emission calculations to authorize the emissions that occur during the scheduled testing of this engine. The use of this engine for emergency conditions will not be authorized by this permit since these events are not subject to GHG permitting requirements.

EPN CR-11; CR Cooling Tower

The make-up water for the cooling tower is treated surface water from the local municipal water district and this water contains naturally occurring dissolved minerals and bicarbonate ions that will tend to concentrate in the cooling tower water, raising the pH and alkalinity. To prevent scale formation, acid is injected into the circulation water system to reduce the alkalinity and pH.

In the process, bicarbonate ion is converted into CO_2 which de-gasses in the cooling tower. CO_2 is discharged to the atmosphere through the mechanical draft cooling tower fan stacks.

The CO_2 emissions are conservatively estimated using the maximum expected bicarbonate concentration and cooling tower make-up water flow rate assuming all the bicarbonate ion is converted to CO_2. In actual practice some bicarbonate remains in the circulating water and is removed with the blowdown water from the cooling tower.

Detailed emission calculations for the cooling tower are provided in Appendix C.

EPN CR-12; C3/C4 Hydrogenation Regeneration Vent – MSS Activities

Hydrogenation reactors will be used to convert olefinic C3 and C4 compounds to saturated compounds. Periodic regeneration of these reactors is required to remove coke and residual hydrocarbon deposits from the catalyst. This regeneration process is started by shutting off the process flow to the reactor and routing the reactor discharge to the quench tower.

Steam is used to sweep hydrocarbons from the reactor into the quench column for recovery of these materials. After the steam sweep is completed, the reactor discharge is routed to an atmospheric vent. High pressure steam and air are used to burn the remaining coke and residual hydrocarbons from the reactor catalyst.

Detailed emission calculations for the hydrogenation regeneration vent MSS activities are provided in Appendix C.

EPNs CR-13, 14, 15 and 16; Ethylene Plant Fugitive Emissions

Fugitive emissions were estimated for the state PSD application for six areas of the proposed facilities: the CR Furnace Area Fugitives (EPN CR-13), the CR Charge Gas Area Fugitives (EPN CR-14), the CR Recovery Area Fugitives (EPN CR-15), the CR C3+ Area Fugitives (EPN CR-16), the CR Waste Treatment and C5 Area Fugitives (EPN CR-17) and the CR LPG Storage Area Fugitives (EPN CR-18). However, since the last two areas do not contain GHG pollutants, they are not included in this GHG application. Calculations utilize SOCMI factors with ethylene, without ethylene and average factors, all based on the ethylene content of the streams. Changes were made based on engineering updates to fugitive emission sources CR-14 and CR-15 in this application update, however, the total fugitive GHG emissions have not changed from the December 2012 application.

GHG fugitive emissions are minimized with the use of a TCEQ 28MID fugitive monitoring and maintenance program with quarterly monitoring of flanges. This program combined with the TCEQ 28CNTQ program (quarterly monitoring of flanges) is a more aggressive program than the TCEQ 28LAER program. New pumps and compressors in VOC service will have dual mechanical seals that route vapor losses to the thermal oxidizers or will be of equivalent non-leaker design.

Relief valves that vent to control devices and relief valves that are equipped with rupture discs and pressure indicators are not identified in the calculations since their control is expected to be 100%. Relief valves associated with contaminated water storage and gasoline storage cannot be equipped with rupture discs since they operate at low pressure. It should be noted that these tanks are initially routed to the thermal oxidizers for control, so losses through the relief valves are a secondary option for managing these tank losses.

VOC and GHG speciation is provided with the fugitive emission calculations. This speciation includes a reasonable GHG distribution for the Ethylene Plant based on materials expected to be processed at the site. Fugitive methane emissions are estimated to be 3 tons/yr and CO_2 emissions are less than 0.1 ton/yr.

Summary calculations are provided for four of the six fugitives areas within the Ethylene Plant since these areas are the only ones that include GHG emissions. These areas include the following: the CR Furnace Area Fugitives (EPN CR-13), the CR Charge Gas Area Fugitives (EPN CR-14), the CR Recovery Area Fugitives (EPN CR-15) and the CR C3+ Area Fugitives (EPN CR-16).

Detailed calculations can be provided for each of about 40 distinct portions of the applicable fugitive areas (those with unique speciation), but due to the volume of the calculations and the relatively small GHG quantities involved, these details are not included in this application. Nevertheless, one example calculation is provided in Appendix C that details the calculations for the binary refrigeration area within the CR Recovery Area Fugitives, EPN CR-15.

EPN CR-19; CR Hydrogen Vent

Hydrogen is a major constituent of the fuel gas which is generated by the cracking process. This fuel gas is used as the primary fuel source for the cracking furnaces and contains a small amount of methane. Engineering calculations indicate that the amount of fuel gas generated and the amount of fuel gas used are very close to being in balance. In the event that more fuel gas is produced than can be consumed, excess fuel must be diverted from the fuel gas system until the fuel balance can be adjusted. Diversion of hydrogen downstream of the Pressure Swing Absorption (PSA) unit is the preferred method of diverting fuel gas as the PSA will remove almost all of the hydrocarbons from the stream prior to venting to atmosphere. Venting of this intermittent stream to atmosphere will result in the lowest environmental impact.

Detailed emission calculations for the hydrogen vent MSS activities are provided in Appendix C.

EPNs CG-1 and CG-2; Existing Cogeneration Units

It should be noted that the existing cogeneration facilities at the site are also considered affected sources for GHG permitting purposes. These cogeneration units are not being modified and their fuel firing will not exceed previously authorized levels (see Texas NSR Permit Nos. 35335 and PSD-TX-880). However, for the purpose of the current permit review, these cogeneration units are considered by EPA to be affected sources that should be used to determine the applicability of federal PSD permitting.

It is likely that the increase in steam and power will occur from increased firing of the gas turbines; but since the higher efficiency turbines' emissions do not represent worst-case, the steam boilers were chosen for the purpose of estimating emission increases. Also, it should be noted that since the two cogeneration facilities are identical, the increased fuel firing could occur from either unit with no difference in the calculated emissions.

Detailed emission calculations for increased fuel firing by the existing cogeneration units are provided in Appendix C.

Proposed GHG Emissions

A summary of maximum GHG emissions to be authorized for the proposed Ethylene Plant is provided below.

GHG Emissions Summary

EPN	Sources	Annual CO_2e Emissions (tons/yr)			
		CO_2-related CO_2e	CH_4-related CO_2e	N_2O-related CO_2e	Total CO_2e
CR-1	Ethane Cracking Furnace No. 1	58,358.20	167.43	494.31	59,019.93
CR-2	Ethane Cracking Furnace No. 2	58,358.20	167.43	494.31	59,019.93
CR-3	Ethane Cracking Furnace No. 3	58,358.20	167.43	494.31	59,019.93
CR-4	Ethane Cracking Furnace No. 4	58,358.20	167.43	494.31	59,019.93
CR-5	Ethane Cracking Furnace No. 5	58,358.20	167.43	494.31	59,019.93
CR-6	CR Thermal Oxidizer No. 1	53,938.77	48.49	140.76	54,128.02
CR-7	CR Thermal Oxidizer No. 2	53,938.77	48.49	140.76	54,128.02
CR-8	CR High Pressure Flare	842.24	0.33	0.49	843.07
CR-8-MSS	CR High Pressure Flare - MSS	69,541.37	76.65	226.29	69,844.31
CR-9	CR Emergency Generator Diesel Engine	61.44	0.05	0.15	61.65
CR-11	CR Cooling Tower	668.14	0.00	0.00	668.14
CR-12-MSS	C3/C4 Hydrogenation Regen. Vent - MSS	12.93	0.03	0.06	13.02
CR-13	CR Furnace Area Fugitives	0.01	28.39	0.00	28.40
CR-14	CR Charge Gas Area Fugitives	0.00	21.05	0.00	21.05
CR-15	CR Recovery Area Fugitives	0.00	11.32	0.00	11.32
CR-16	CR C3+ Area Fugitives	0.00	5.42	0.00	5.42
CR-19	Hydrogen Vent	0.00	30.24	0.00	30.24
Totals		**470,794.69**	**1,107.59**	**2,980.06**	**474,882.33**

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) REGULATORY REQUIREMENTS

OxyChem's new Ethylene Plant will comply with all applicable PSD regulatory requirements. Details of these permitting requirements and the company's compliance are explained below for the requirements found in 40 CFR 52.21(j)-(w).

(j) Control technology review

One aspect of the required control technology review is that a major stationary source or major modification must comply with each applicable emissions limitation under the State Implementation Plan and each applicable emission standard and standard of performance under 40 CFR parts 60 and 61. However, since GHG emissions are not addressed in these requirements, the proposed facilities are not subject to any of these standards.

Also, new major stationary sources and major modifications must apply best available control technology (BACT) for each regulated NSR pollutant subject to PSD review. The review of BACT using the EPA's five-step, top-down BACT approach, typically includes the following items for each source category: 1) the identification of available control technologies; 2) the elimination of the technically infeasible alternatives; 3) the ranking of the remaining control technologies; 4) the evaluation of the most effective controls regarding cost-effectiveness, energy impacts, and environmental effects; and 5) the selection of BACT.

For the sources associated with the proposed facilities, this BACT review is provided in Appendix D, Best Available Control Technology Review. It should be noted that the existing cogeneration units are not subject to BACT since they are not modified sources. The cogeneration units are included in this application because they are considered affected facilities that influence PSD applicability.

(k) Source impact analysis

Subsection (k) requirements prevent a proposed source or modification from causing or contributing to a violation of a national ambient air quality standard (NAAQS) or an applicable maximum allowable increase over the baseline concentration in any area. However, since NAAQS and baseline concentrations have not been established for GHGs, these requirements are not relevant to this application.

(l) Air quality models

Subsection (l) requirements specify that all estimates of ambient concentrations must be based on applicable air quality models, data bases, and other requirements specified in Appendix W of 40 CFR 51 (Guideline on Air Quality Models). However, since no air quality modeling is required for GHGs, these specifications are not applicable.

(m) Air quality analysis

The air quality requirements for pre-application monitoring and post-construction monitoring in Subsection (m) of the rules are not required for GHGs since EPA regulations provide an exemption in 40 CFR 52.21(i)(5)(iii) and 51.166(i)(5)(iii) for pollutants, including GHGs, that are not listed in the appropriate section of the regulations. Therefore, it is understood that the EPA does not require applicants to gather monitoring data to evaluate ambient air quality for GHGs under 40 CFR 52.21(m)(1)(ii), 40 CFR 51.166(m)(1)(ii) or similar provisions.

(n) Source information

The GHG permit applicant is required to provide all information necessary to perform any analysis or make any determination required under these PSD rules, including the following: a description of the nature, location, design capacity and typical operating schedule of the source, a schedule for construction of the source, a detailed description of emission controls, emission estimates and any other information necessary relative to demonstrating BACT. This information is provided in the previous process discussion and in Appendices A, B, C and D.

Also, it is understood that upon request of the Administrator, the applicant must provide information on the air quality impact of the new sources, including meteorological and topographical data necessary to estimate such impact, and the nature and extent of any or all general commercial, residential, industrial, and other growth expected to occur as a result of the proposed project. However, since air quality analysis for GHGs is not required, OxyChem does not anticipate being requested to provide this information.

In addition, it is understood that EPA is required to ensure compliance with the Endangered Species Act, the National Historic Preservation Act, Environmental Justice mandates, and the Magnuson-Stevens Fishery Conservation and Management Act, as applicable to agency decisions regarding the GHG PSD permit issuance process.

Endangered Species Act (ESA):

OxyChem will serve as its non-federal agent for informal consultation and the associated compliance review process pursuant to ESA. The U.S. Fish and Wildlife Service (USFWS) office of jurisdiction will likely be the Corpus Christi Field Office.

OxyChem's understanding is that the initial informal consultation process typically includes identifying the list of federally-listed threatened and endangered (T&E) species that may occur in each county within the action area, collecting existing baseline information on each species (e.g., habitat requirements, approved survey protocols, known records of occurrence, etc.), performing potential habitat surveys of the action area, and identifying potential occurrences and associated project impacts on each species.

If no T&E species are listed within the action area, then the USFWS typically would concur with a "no effect" determination. If no known occurrences or potential habitat for identified T&E species are present within the action area, then the USFWS typically would concur with a "not likely to adversely affect" determination. Either of these determinations would conclude the informal consultation process, and obviate the need to enter into formal consultation.

The formal consultation process is reserved for projects that are likely to adversely affect a federally-listed T&E species. Under this process, the EPA would request that OxyChem conduct any required in-field, habitat and species-specific surveys, prepare a Biological Assessment (BA) on behalf of EPA, and file the BA with USFWS. If upon BA review, the USFWS determines the project is not likely to adversely affect a T&E species, the formal consultation is then concluded.

OxyChem's documentation in satisfaction of these requirements is separate from the current GHG PSD permit application submittal. These reports were submitted to EPA in June of 2013.

National Historic Preservation Act (NHPA):

For the proposed Ethylene Plant, an approval letter from the Executive Director of the Texas Historical Commission (THC) will likely meet the EPA's NHPA compliance requirements. The EPA will retain primary consultation authority for NHPA compliance, and will not request that OxyChem serve as its non-federal agent. A Cultural Resource Report was submitted to EPA in July of 2013 for review and submittal to THC.

Environmental Justice (EJ):

OxyChem's understanding is that the EPA will be responsible for evaluating whether operation of the proposed ethylene production facilities will result in an EJ concern. The EPA is expected to run a model to perform the EJ evaluation. The EPA does not anticipate that OxyChem will need to perform any additional evaluations.

Magnuson-Stevens Fishery Conservation and Management Act (MSFCMA):

For the proposed Ethylene Plant, an approval letter from the National Oceanic and Atmospheric Administration-National Marine Fisheries Service (NOAA-NMFS), Habitat Conservation Division, Galveston Office will likely meet the EPA's MSFCMA compliance requirements. OxyChem understands that the EPA will retain primary consultation authority for MSFCMA compliance and will not request that OxyChem serve as its non-federal agent.

OxyChem submitted an Essential Fish Habitat (EFH) Assessment in June of 2013 for EPA review and submittal to NMFS-Habitat Conservation Division.

(o) Additional impact analyses

Subsection (o) requirements typically result in an analysis of the potential impairment to visibility, soils and vegetation that may occur as a result of the proposed source or modification and the expected general commercial, residential, industrial and other growth. Also, the Administrator may require monitoring of visibility in any nearby Federal Class I area.

However, an impact analysis is not required for GHG pollutants. The EPA's document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" prepared by the Office of Air Quality Planning and Standards and dated March 2011, states the EPA's belief that it is not necessary for applicants to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for several reasons. The reasons provided by the EPA are that climate change modeling and impact evaluations are typically conducted for changes in emissions much larger than those from individual projects and that quantifying the impacts from a specific, permitted GHG source would not be possible with current climate change models.

This EPA document concludes that the most practical approach to addressing Class I areas and additional impacts analysis is to focus on maximizing the reduction of GHGs through compliance with the BACT analysis.

(p) Sources impacting Federal Class I areas - additional requirements

Subsection (p) rules include the requirement that the Administrator provide written notice of the permit application and provide other information for a proposed major stationary source or major modification when the emissions may affect a Federal Class I area. Since the nearest Class I area is the Big Bend National Park, which is located more than 350 miles (600 kilometers) from the proposed facilities, the emissions from this project are not expected to have an impact on this Class I area. In addition, the EPA position explained in Item (o) regarding additional impact analyses appears to apply to these additional Class I concerns.

(q) Public participation

Subsection (q) rules place certain requirements on the Administrator to follow the applicable public notice procedures of 40 CFR Part 124 in processing applications under this section. It is expected that the Administrator will follow the procedures at 40 CFR 52.21(r) to the extent that the procedures of 40 CFR Part 124 do not apply.

(r) Source obligation

It is understood that these requirements preclude an owner or operator from constructing or operating a source or modification not in accordance with the application submitted pursuant to these PSD requirements or with the terms of the issued permit. In addition, it is understood that the permit is invalid if construction is not commenced within 18 months after receipt of the permit (unless an extension is authorized), if construction is discontinued for a period of 18 months or more, and if construction is not completed within a reasonable time.

(s) Environmental impact statements

These rules state that whenever a proposed source is subject to permitting action by a federal agency that might necessitate preparation of an environmental impact statement pursuant to the National Environmental Policy Act (NEPA, 42 U.S.C. 4321), review by the Administrator conducted pursuant to this section shall be coordinated with the environmental reviews under that Act and under Section 309 of the Clean Air Act. However, it appears that NEPA is not applicable to this GHG permit action because of the exemption from NEPA for air permitting (15 USC § 793(c)).

(t) Disputed permits or redesignations

OxyChem understands that certain affected parties who determine a proposed permit will cause or contribute to a cumulative change in air quality in excess of that allowed by these rules may request the Administrator to enter into negotiations with the parties involved to resolve the concerns.

(u) Delegation of authority

OxyChem understands that the delegation of responsibility for conducting GHG source review permitting has not finalized in Texas, and therefore, this application is being submitted to the Region 6 Office of the EPA, and copied to the TCEQ.

(v) Innovative control technology

OxyChem understands that certain regulatory options exist for implementing innovative control technology for a PSD permit. However, no innovative controls are proposed for the new ethylene production facilities.

(w) Permit rescission

OxyChem understands that a permit issued under these PSD rules shall remain in effect, unless and until it expires under the regulations referenced above or is rescinded.

APPENDIX A
GENERAL APPLICATION AND PSD APPLICABILITY FORMS

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

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

I.	Applicant Information	
A. Company or Other Legal Name: Occidental Chemical Corporation		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name: John Zylks		
Title: Asst. Plant Manager		
Mailing Address: P.O. Box CC		
City: Ingleside	State: TX	ZIP Code: 78362-0720
Telephone No.: (361) 776-6169	Fax No.: (361) 776-6240	E-mail Address: Mark_Evans@oxy.com
C. Technical Contact Name: Mark R. Evans		
Title: Environmental Manager - Projects		
Company Name: Occidental Chemical Corporation		
Mailing Address: P.O. Box CC		
City: Ingleside	State: TX	ZIP Code: 78362-0720
Telephone No.: (361) 776-6169	Fax No.: (361) 776-6240	E-mail Address: Mark_Evans@oxy.com
D. Site Name: Ingleside Chemical Plant		
E. Area Name/Type of Facility: Ethylene Plant		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Chemical Manufacturing		
Principal Standard Industrial Classification Code (SIC): 2869		
Principal North American Industry Classification System (NAICS): 325199		
G. Projected Start of Construction Date: 6/30/14		
Projected Start of Operation Date: 9/30/16		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 4133 Hwy 361; 2 miles west of Hwy 1069 on Hwy 361		
City/Town: Gregory	County: San Patricio	ZIP Code: 78359
Latitude (nearest second): 27° 52' 51"	Longitude (nearest second): 97° 14' 39"	

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

I.	**Applicant Information (continued)**	
I.	Account Identification Number (leave blank if new site or facility): SD-0092-F	
J.	Core Data Form.	
Is the Core Data Form (Form 10400) attached? If No, provide customer reference number and regulated entity number (complete K and L).		☐ YES ☒ NO
K.	Customer Reference Number (CN): 600125256	
L.	Regulated Entity Number (RN): 100211176	
II.	**General Information**	
A.	Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.	☐ YES ☒ NO
B.	Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.	☐ YES ☒ NO
C.	Number of New Jobs: 123	
D.	Provide the name of the State Senator and State Representative and district numbers for this facility site:	
State Senator: Judith Zarrafini		District No.: 21
State Representative: J.M. Lazano		District No.: 43
III.	**Type of Permit Action Requested**	
A.	Mark the appropriate box indicating what type of action is requested.	
☒ Initial ☐ Amendment ☐ Revision (30 TAC 116.116(e) ☐ Change of Location ☐ Relocation		
B.	Permit Number (if existing):	
C.	Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)*	
☒ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit		
☒ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source		
☐ Other:		
D.	Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

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

III.	**Type of Permit Action Requested *(continued)***		
E.	Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.0		☐ YES ☒ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):			
Street Address:			
City:	County:	ZIP Code:	
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):			
Street Address:			
City:	County:	ZIP Code:	
3.	Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO", attach detailed information.		☐ YES ☐ NO
4.	Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?		☐ YES ☐ NO
F.	Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.		
List: none			
G.	Are you permitting planned maintenance, startup, and shutdown emissions? If Yes, attach information on any changes to emissions under this application as specified in VII and VIII.		☒ YES ☐ NO
H.	Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) Is this facility located at a site required to obtain a federal operating permit? If Yes, list all associated permit number(s), attach pages as needed).	☒ YES ☐ NO ☐ To be determined	
Associated Permit No (s.): O1240 for the existing site; a new permit will be requested for the proposed facilities			
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.			
☒ FOP Significant Revision	☐ FOP Minor	☐ Application for an FOP Revision	
☐ Operational Flexibility/Off-Permit Notification		☐ Streamlined Revision for GOP	
☐ To be Determined		☐ None	

III. Type of Permit Action Requested *(continued)*		
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*		
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)***		
☐ GOP Issued	☐ GOP application/revision application submitted or under APD review	
☒ SOP Issued	☒ SOP application/revision application submitted or under APD review	
IV. Public Notice Applicability		
A. Is this a new permit application or a change of location application?		☒ YES ☐ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.		☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?		☒ YES ☐ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?		☐ YES ☒ NO
If Yes, list the affected state(s) and/or Class I Area(s).		
List:		
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.		☐ YES ☒ NO
1. Is there any change in character of emissions in this application?		☐ YES ☐ NO
2. Is there a new air contaminant in this application?		☐ YES ☐ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?		☐ YES ☐ NO
F. List the total annual emission increases associated with the application ***(List all that apply and attach additional sheets as needed):***		
Greenhouse Gases (GHG): 474,882.33 tons/yr		
Volatile Organic Compounds (VOC):		
Sulfur Dioxide (SO2):		
Carbon Monoxide (CO):		
Nitrogen Oxides (NOx):		
Particulate Matter (PM):		
PM 10 microns or less (PM10):		
PM 2.5 microns or less (PM2.5):		
Hazardous Air Pollutants (HAPs):		
Other speciated air contaminants not listed above:		

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

V. Public Notice Information *(complete if applicable)*		
A. Public Notice Contact Name: Mark R. Evans		
Title: Environmental Manager - Projects		
Mailing Address: P.O.Box CC		
City: Ingleside	State: TX	ZIP Code: 78362-0720
B. Name of the Public Place: Bell Whittington Public Library		
Physical Address *(No P.O. Boxes)*: 2400 Memorial Parkway		
City: Portland	County: San Patricio	ZIP Code: 78374
The public place has granted authorization to place the application for public viewing and copying.		☒ YES ☐ NO
The public place has internet access available for the public.		☒ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits		
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable: Judge Terry A. Simpson		
Mailing Address: 400 West Sinton Street #109		
City: Sinton	State: TX	ZIP Code: 78387
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located.		
Chief Executive: Mayor Freddy Garcia		
Mailing Address: 204 W 4th Street		
City: Gregory	State: TX	ZIP Code: 78359
Name of the Indian Governing Body: N/A		
Mailing Address:		
City:	State:	ZIP Code:

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

V.	**Public Notice Information *(complete if applicable) (continued)***	
C.	Concrete Batch Plants, PSD, and Nonattainment Permits	
3.	Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. *(continued)*	
Name of the Federal Land Manager(s):		
D.	Bilingual Notice	
Is a bilingual program required by the Texas Education Code in the School District?		☐ YES ☒ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?		☐ YES ☒ NO
If Yes, list which languages are required by the bilingual program?		
VI.	**Small Business Classification *(Required)***	
A.	Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?	☐ YES ☒ NO
B.	Is the site a major stationary source for federal air quality permitting?	☒ YES ☐ NO
C.	Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?	☒ YES ☐ NO
D.	Are the site emissions of all regulated air pollutants combined less than 75 tpy?	☐ YES ☒ NO
VII.	**Technical Information**	
A.	The following information must be submitted with your Form PI-1 ***(this is just a checklist to make sure you have included everything)***	
1.	☒ Current Area Map	
2.	☒ Plot Plan	
3.	☒ Existing Authorizations	
4.	☒ Process Flow Diagram	
5.	☒ Process Description	
6.	☒ Maximum Emissions Data and Calculations	
7.	☒ Air Permit Application Tables	
a.	☒ Table 1(a) (Form 10153) entitled, Emission Point Summary	
b.	☒ Table 2 (Form 10155) entitled, Material Balance	
c.	☒ Other equipment, process or control device tables	
B.	Are any schools located within 3,000 feet of this facility?	☐ YES ☒ NO

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

VII.	**Technical Information**			
C.	Maximum Operating Schedule:			
Hour(s): 24	Day(s): 7	Week(s): 52	Year(s):	
Seasonal Operation? If Yes, please describe in the space provide below.				☐ YES ☒ NO
D.	Have the planned MSS emissions been previously submitted as part of an emissions inventory?			☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.				
E.	Does this application involve any air contaminants for which a disaster review is required?			☒ YES ☐ NO
F.	Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)?			☐ YES ☒ NO
VIII.	**State Regulatory Requirements** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*			
A.	Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?			☒ YES ☐ NO
B.	Will emissions of significant air contaminants from the facility be measured?			☒ YES ☐ NO
C.	Is the Best Available Control Technology (BACT) demonstration attached?			☒ YES ☐ NO
D.	Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?			☒ YES ☐ NO
IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*			
A.	Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?			☒ YES ☐ NO
B.	Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?			☒ YES ☐ NO

IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	
Is the estimated capital cost of the project greater than $2 million dollars?		☒ YES ☐ NO
If Yes, submit the application under the seal of a Texas licensed P.E.		
XI.	**Permit Fee Information**	
Check, Money Order, Transaction Number ,ePay Voucher Number:		Fee Amount:
Paid online?		☐ YES ☐ NO
Company name on check:		
Is a copy of the check or money order attached to the original submittal of this application?		☐ YES ☐ NO ☐ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?		☐ YES ☐ NO ☐ N/A

XII. Delinquent Fees and Penalties
This form will not be processed until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.

XIII. Signature
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name: John Zylks
Signature: John K Zylks *Original Signature Required*
Date: 1/14/14

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant: GHG	Permit: To be assigned
Baseline Period: 1/1/10 to 12/31/11	

	Affected or Modified Facilities FIN	EPN	Permit No.	Actual Emissions	A Baseline Emissions	B Proposed Emissions	Projected Actual Emissions	Difference (A-B)	Correction	Project Increase
1	CR-1	CR-1	tba	0.00	0.00	59,019.94		59,019.94		59,019.94
2	CR-2	CR-2	tba	0.00	0.00	59,019.94		59,019.94		59,019.94
3	CR-3	CR-3	tba	0.00	0.00	59,019.94		59,019.94		59,019.94
4	CR-4	CR-4	tba	0.00	0.00	59,019.94		59,019.94		59,019.94
5	CR-5	CR-5	tba	0.00	0.00	59,019.94		59,019.94		59,019.94
6	CR-5-MSS	CR-10	tba	0.00	0.00	0.00		0.00		0.00
7	CR-6	CR-11	tba	0.00	0.00	54,128.02		54,128.02		54,128.02
8	CR-7	CR-12	tba	0.00	0.00	54,128.02		54,128.02		54,128.02
9	CR-8	CR-13	tba	0.00	0.00	843.06		843.06		843.06
10	CR-8-MSS	CR-14	tba	0.00	0.00	69,844.31		69,844.31		69,844.31
11	CR-9	CR-9	tba	0.00	0.00	61.64		61.64		61.64
12	CR-11	CR-11	tba	0.00	0.00	668.14		668.14		668.14
13	CR-12	CR-12	tba	0.00	0.00	13.02		13.02		13.02
14	CR-13	CG-13	tba	0.00	0.00	28.40		28.40		28.40
								Page Subtotal		474,814.30*

* The page subtotal corrects for some rounding elements of the application's EXCEL spreadsheet calculations for these sources.

TCEQ

TABLE 2F (cont'd)
PROJECT EMISSION INCREASE

Pollutant: GHG	**Permit:** To be assigned
Baseline Period: 1/1/10 to 12/31/11	

	Affected or Modified Facilities FIN	EPN	Permit No.	Actual Emissions	A Baseline Emissions	B Proposed Emissions	Projected Actual Emissions	Difference (A-B)	Correction	Project Increase
15	CR-14	CR-14	tba	0.00	0.00	21.05		21.05		21.05
16	CR-15	CR-15	tba	0.00	0.00	11.32		11.32		11.32
17	CR-16	CR-16	tba	0.00	0.00	5.42		5.42		5.42
18	CR-19	CR-19	tba	0.00	0.00	30.24		30.24		30.24
19	CG-1/CG-2	CG-1/CG-2	tba	0.00*	0.00*	110,201.28		110,201.28		110,201.28
20										
21										
22										
23										
24										
25										
26										
27							**Page Subtotal**			110,269.31
28							**Previous Page Subtotal**			474,814.30
							GHG Total			585,083.61

* Baseline emissions are not needed for sources that are not modified. These cogeneration units are affected sources that will provide steam and power to the new Ethylene Plant, but they are not modified. Their increased criteria pollutant emission rates will not exceed permit limits that were previously authorized under Permit Nos. 35335 and PSD-TX-880.

TCEQ

TABLE 3F
PROJECT CONTEMPORANEOUS CHANGES

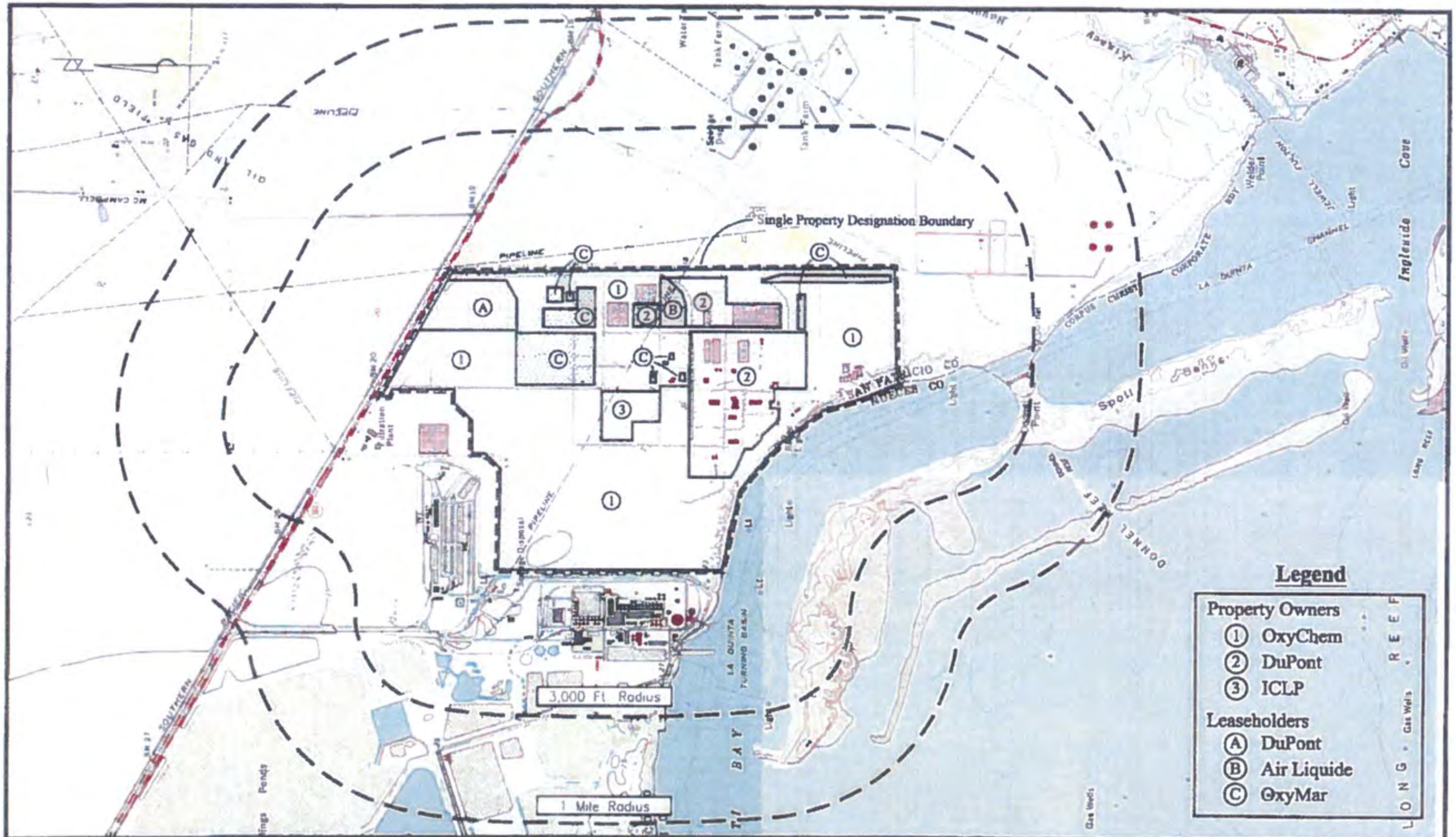
Company: Occidental Chemical Corporation

Permit Application Number: To be assigned | **Criteria Pollutant:** GHG

	Project Date	Facility at Which Emission Change Occurred FIN	EPN	Permit No.	Project Name or Activity	A Baseline Period	B Baseline Emissions (tons/year)	Proposed Emissions (tons/year)	Difference (A-B)	Creditable Decrease or Increase
1	2/2017	CR-1 thru CR16; CG-1 and CG-2	CR-1 thru CR16; CG-1 and CG-2	To be assigned	Ethylene Plant	1/10-12/11	0.00	585,083.61	585,083.61	585,083.61
2	7/2014	NGL-1 thru 14; CG-1 and CG-2	NGL-1 thru 14; CG-1 and CG-2	PSD-TX-1292-GHG	NGL Fractionation Facilities	1/10-12/11	0.00	243,367.87*	243,367.87	243,367.87
3										
4										
5										
6										
7										
8										
9										
10										
11										
						Page Subtotal				828,451.48
									Project Emission	828,451.48
Summary of Contemporaneous Changes							Total			828,451.48

* The 243,367.87 tons/yr increase is the sum of 242,536.30 tons/yr, indicated in the initial application, and 831.57 tons/yr, indicated in the deficiency response dated August 1, 2012.

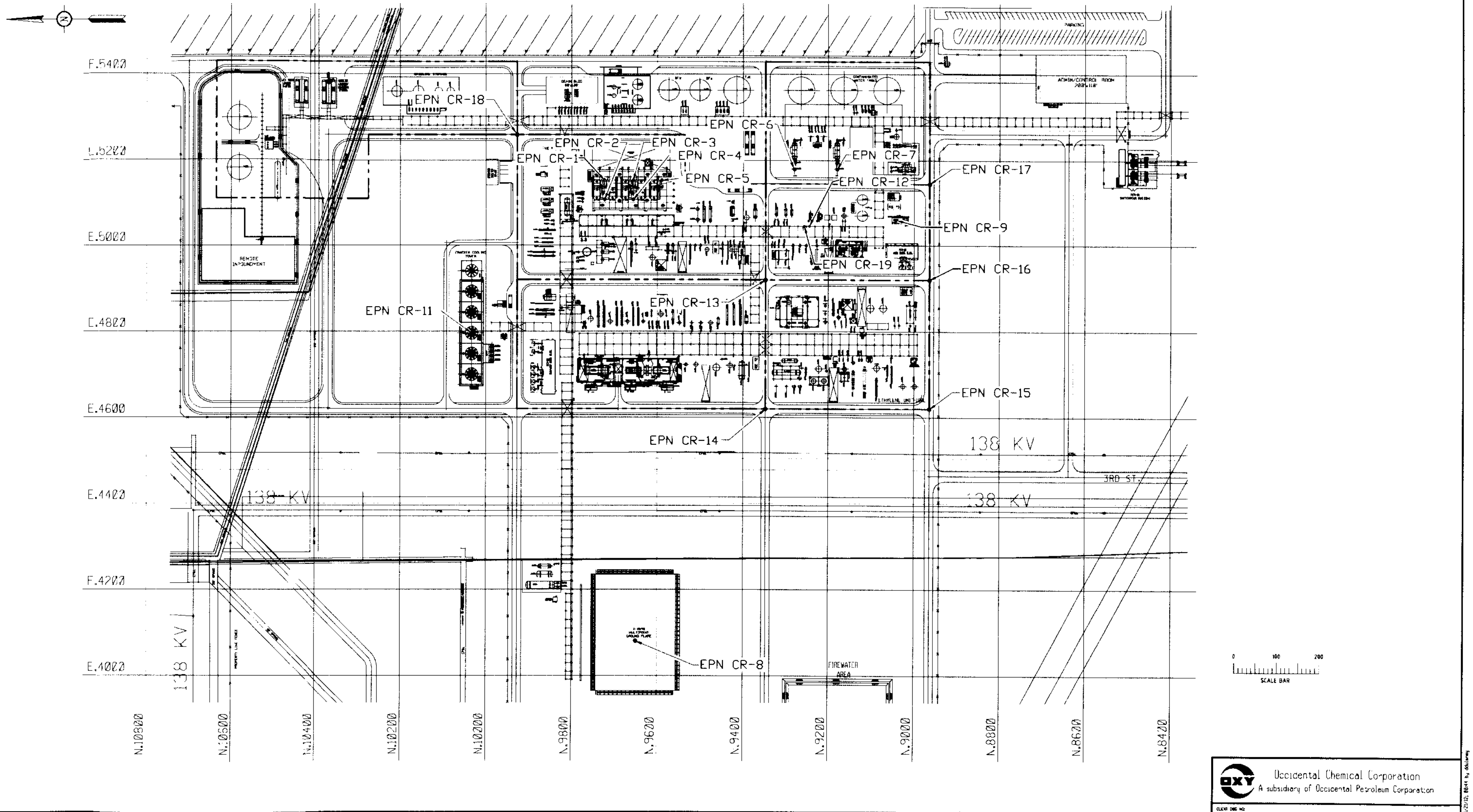
APPENDIX B
AREA MAP, PLOT PLAN AND OTHER SUPPORTING DOCUMENTS



Occidental Chemical Corporation (OxyChem)
2 Miles West of Highway 1069 on Highway 361
Gregory, Texas 78359
Gregory, Aransas Pass, Portland, and Port Ingleside, Texas Quadrangles; UTM Zone 15

Additions to the USGS map by Austin CAD Services, Austin, Texas

QUADRANGLE LOCATION



NO.	REVISION	DRAWN	CKD	APPD	DATE
F	ISSUED FOR INFORMATION	RP	RR	MP	05 APR 13
E	ISSUED FOR INFORMATION	RP	RR	MP	15-MAR-13
D	ISSUED FOR INFORMATION	RP	RR	MP	14 MAR 13
C	ISSUED FOR CLIENT REVIEW	RR	DG	RWN	10-DEC-12
H	ISSUED FOR INFORMATION (PER VALUE ENGINEERING)	RP	RR	MP	07 JUN 13
G	ISSUED FOR INFORMATION	RP	RR	MP	12-APR-13

NOTES

REFERENCE DRAWINGS

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DRAWN: RR | CKD: DG | APPD: RWN | DATE: 13NOV12 | SCALE: SEE SCALE BAR

Occidental Chemical Corporation
A subsidiary of Occidental Petroleum Corporation

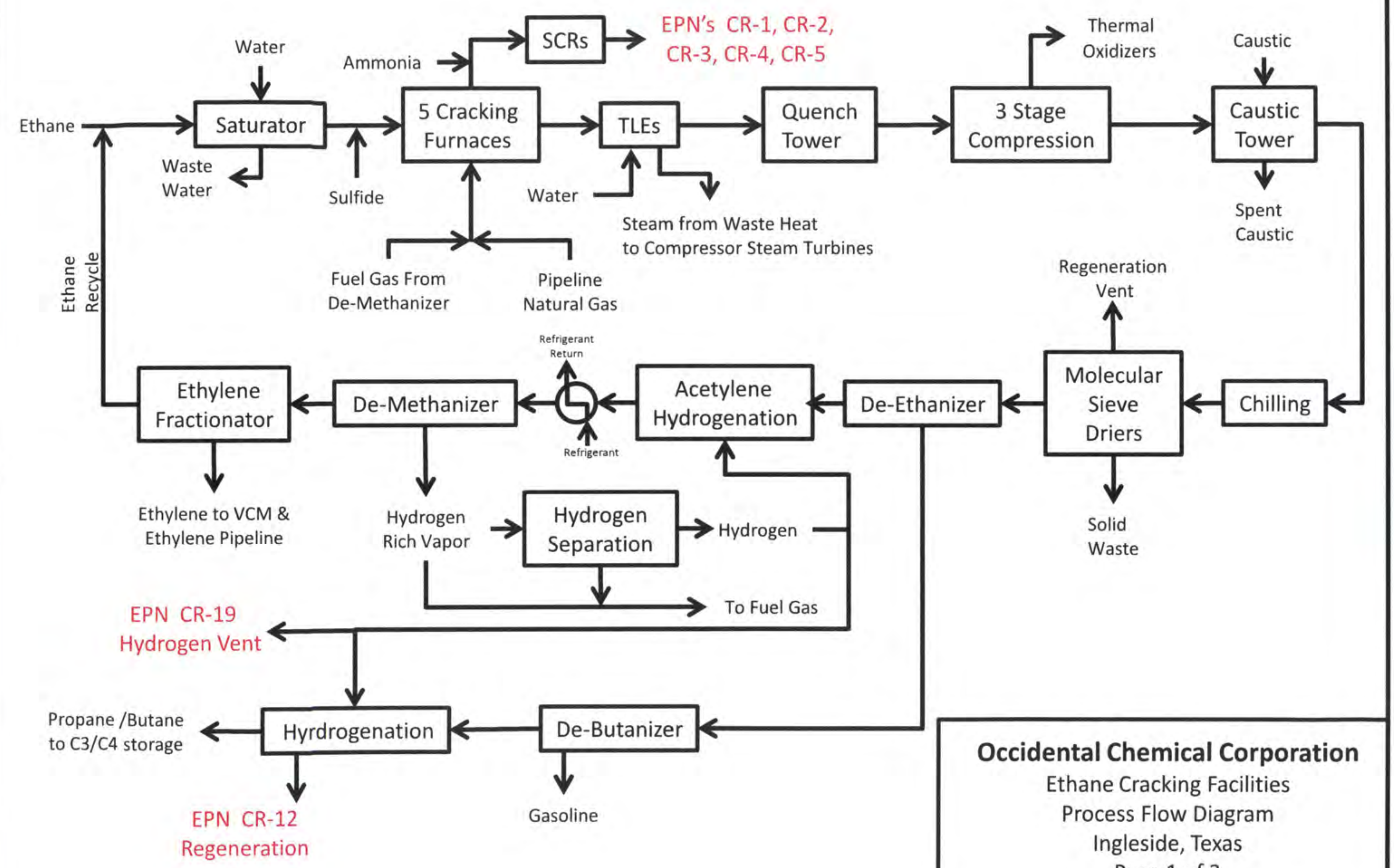
CLIENT DWG NO

OXY INGLESIDE ETHYLENE PLANT
EMISSION POINTS SOURCES

FOR Occidental Chemical Corporation

PROJECT NO 181872 | DWG NO 181872-000-HS-08-0C0002.001 | REV. H

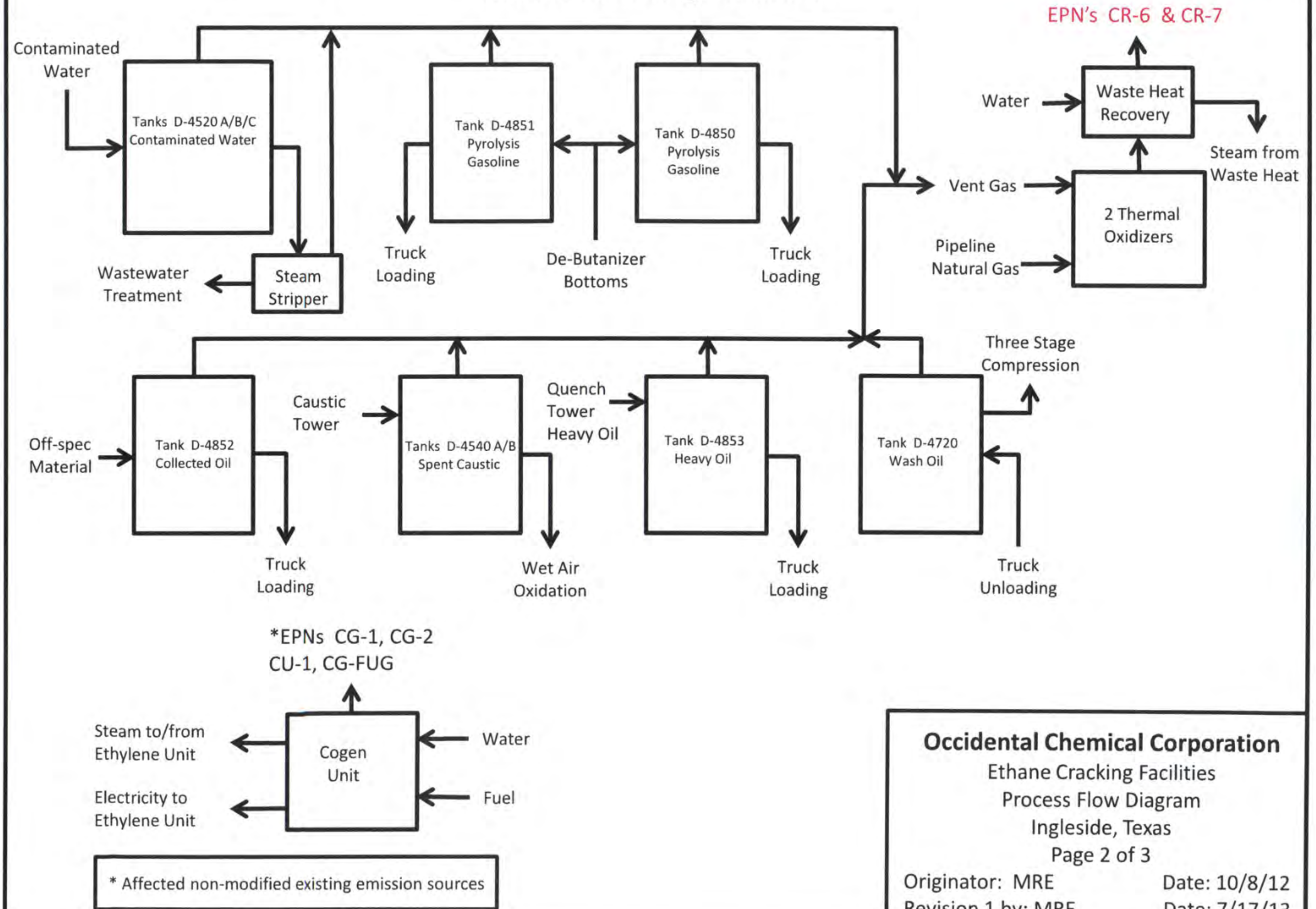
Ethane Cracking Facilities



Occidental Chemical Corporation
Ethane Cracking Facilities
Process Flow Diagram
Ingleside, Texas
Page 1 of 3

Originator: MRE — Date: 10/8/12
Revision 1 by: MRE — Date: 7/17/13

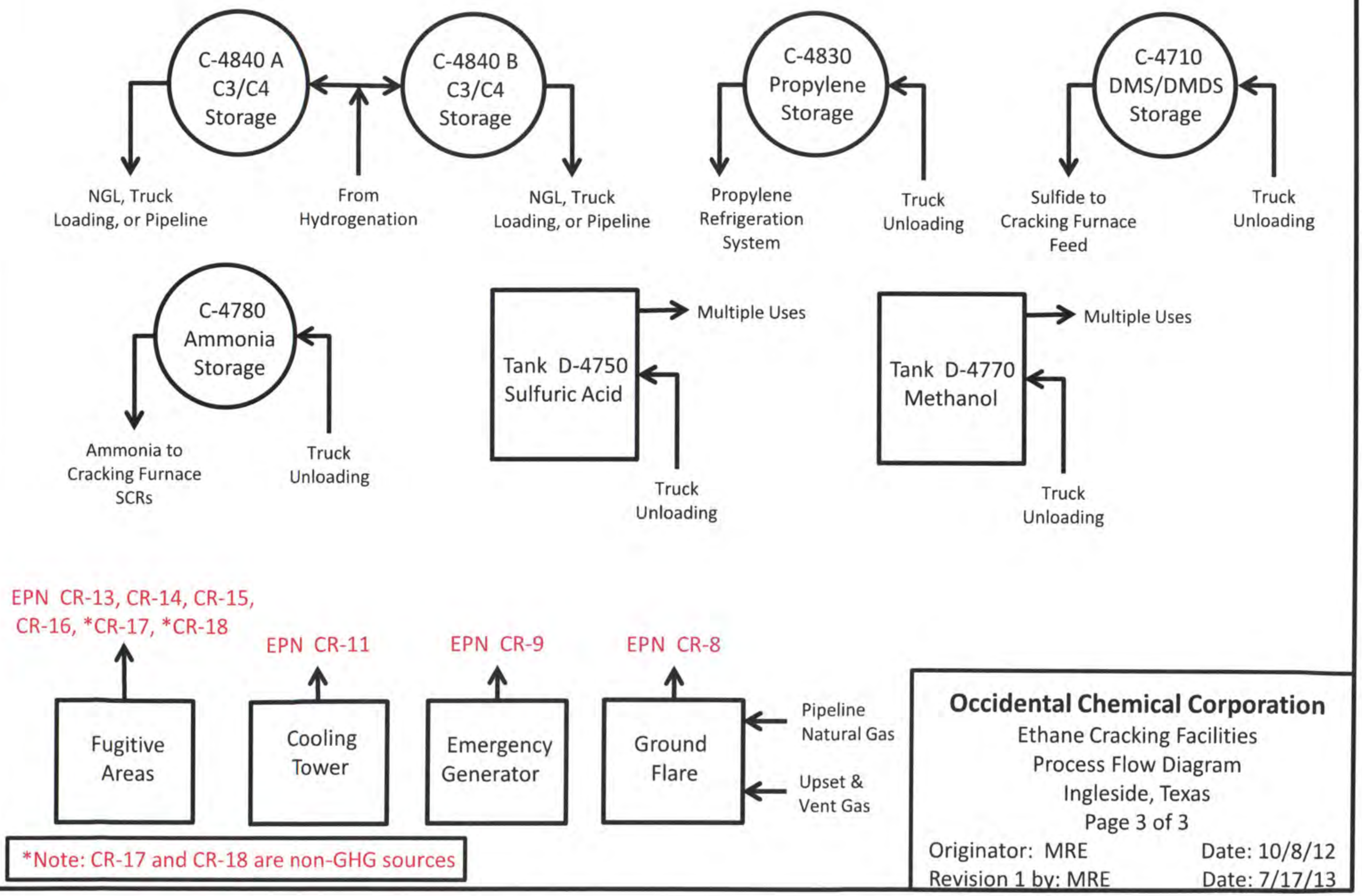
Ethane Cracking Facilities



Occidental Chemical Corporation
Ethane Cracking Facilities
Process Flow Diagram
Ingleside, Texas
Page 2 of 3

Originator: MRE Date: 10/8/12
Revision 1 by: MRE Date: 7/17/13

Ethane Cracking Facilities



Occidental Chemical Corporation
Ethane Cracking Facilities
Process Flow Diagram
Ingleside, Texas
Page 3 of 3

Originator: MRE — Date: 10/8/12
Revision 1 by: MRE — Date: 7/17/13

Table 2
Material Balance

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

List Every Material Involved in Each of the Following Groups	Point Number from Flow Diagram	Process Rates (lb/hr or SCFM) Standard Conditions: 70 °F, 14.7 psia	Measurement	Estimation	Calculation
1. Raw Materials - Input					
Ethane Feed		185,000 lb/hr		X	
2. Fuels - Input					
Natural Gas		61,000 lb/hr		X	
Fuel Gas		28,800 lb/hr		X	
3. Products & Byproducts - Output					
Ethylene		142,800 lb/hr		X	
Propane/Butane Mix		9,700 lb/hr		X	
PyGas (Gasoline)		4,000 lb/hr		X	
Fuel Gas		28,800 lb/hr		X	
4. Solid Wastes - Output					
Coke, Spent Dessiccant, Catalysts and Misc. Waste		280,000 lb/yr		X	
5. Liquid Wastes - Output					
Saturator Blowdown, Spent Caustic, Boiler Blowdown, Cooling Tower Blowdown, Rain and Wash Down Water		37,000 lb/hr		X	
6. Airborne Waste (Solid) - Output					
$PM/PM_{10}/PM_{2.5}$		See Table 1(a)		X	
7. Airborne Waste (Gaseous) - Output					
NO_x, CO, VOC, HAP, SO_2, H_2SO_4, NH_3, and Cl_2		See Table 1(a)		X	

Notes:

1) All information is preliminary and may change based on the vendor information and/or the final engineering design.

APPENDIX C
EMISSION CALCULATIONS

GHG Emissions Summary

EPN	Sources	Annual GHG Emissions (tons/yr)			Global Warming Potential Factors			Annual CO_2e Emissions (tons/yr)			
		CO_2	CH_4	N_2O	CO_2	CH_4	N_2O	CO_2-related CO_2e	CH_4-related CO_2e	N_2O-related CO_2e	Total CO_2e
CR-1	Ethane Cracking Furnace No. 1	58,358.20	7.97	1.59	1	21	310	58,358.20	167.43	494.31	59,019.93
CR-2	Ethane Cracking Furnace No. 2	58,358.20	7.97	1.59	1	21	310	58,358.20	167.43	494.31	59,019.93
CR-3	Ethane Cracking Furnace No. 3	58,358.20	7.97	1.59	1	21	310	58,358.20	167.43	494.31	59,019.93
CR-4	Ethane Cracking Furnace No. 4	58,358.20	7.97	1.59	1	21	310	58,358.20	167.43	494.31	59,019.93
CR-5	Ethane Cracking Furnace No. 5	58,358.20	7.97	1.59	1	21	310	58,358.20	167.43	494.31	59,019.93
CR-1-5-MSS	Ethane Cracking Furnace Nos. 1-5 - MSS Activities	na	na	na	1	21	310	0.00	0.00	0.00	0.00
CR-6	CR Thermal Oxidizer No. 1	53,938.77	2.31	0.45	1	21	310	53,938.77	48.49	140.76	54,128.02
CR-7	CR Thermal Oxidizer No. 2	53,938.77	2.31	0.45	1	21	310	53,938.77	48.49	140.76	54,128.02
CR-8	CR High Pressure Flare	842.24	0.02	0.00	1	21	310	842.24	0.33	0.49	843.07
CR-8-MSS	CR High Pressure Flare - MSS Activities	69,541.37	3.65	0.73	1	21	310	69,541.37	76.65	226.29	69,844.31
CR-9	CR Emergency Generator Diesel Engine	61.44	0.00	0.00	1	21	310	61.44	0.05	0.15	61.65
CR-11	CR Cooling Tower	668.14	0.00	0.00	1	21	310	668.14	0.00	0.00	668.14
CR-12-MSS	C3/C4 Hydrogenation Regen. Vent - MSS Activities	12.93	0.00	0.00	1	21	310	12.93	0.03	0.06	13.02
CR-13	CR Furnace Area Fugitives	0.01	1.35	0.00	1	21	310	0.01	28.39	0.00	28.40
CR-14	CR Charge Gas Area Fugitives	0.00	1.00	0.00	1	21	310	0.00	21.05	0.00	21.05
CR-15	CR Recovery Area Fugitives	0.00	0.54	0.00	1	21	310	0.00	11.32	0.00	11.32
CR-16	CR C3+ Area Fugitives	0.00	0.26	0.00	1	21	310	0.00	5.42	0.00	5.42
CR-19	Hydrogen Vent	0.00	1.44	0.00	1	21	310	0.00	30.24	0.00	30.24
Totals								470,794.69	1,107.59	2,980.06	474,882.33

Occidental Chemical Corporation
January 2014

Ethane Cracking Furnace Nos. 1-5

EPN's CR-1, CR-2, CR-3, CR-4 and CR-5

Estimated Emissions Based on Maximum Natural Gas Firing
(Worst-Case Calculations for Furnace CO2)

Basis:

275 MM Btu/hr, maximum, total natural gas fuel firing rate
116.91 lb/MM Btu, CO2 factor for natural gas from 40 CFR 98, Subpart C, Table C-1 (converted from 53.02 kg/MM Btu for use with Eq. C-1b)
0.002 lb/MM Btu, CH4 factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.001 kg/MM Btu for use with Eq. C-8b)
0.0002 lb/MM Btu, N2O factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.0001 kg/MM Btu for use with Eq. C-8b)
8,760 hr/yr, hours of operation
Emission calculations below represent maximum emissions for each of the five furnaces

Pollutant	Emission Factor (lb/MM Btu)	Hourly Emissions (lb/hr)	Annual Emissions (tons/yr)
CO_2	116.91	32,150.00	140,817.01
CH_4	0.002	0.61	2.66
N_2O	0.0002	0.06	0.27

Calculation methods:

Hourly emissions (lb/hr) = emission factor (lb/MM Btu) x fuel firing rate (MM Btu/hr)
Annual emissions (tons/yr) = hourly emissions (lb/hr) x hours of operation (hr/yr) x 1 ton/2,000 lb

Occidental Chemical Corporation
January 2014

Ethane Cracking Furnace Nos. 1-5

EPN's CR-1, CR-2, CR-3, CR-4 and CR-5

Estimated Emissions Based on Maximum Process-Generated Fuel Gas (Hydrogen) Firing
(Worst-Case Calculations for Furnace CH4 and N2O)

Basis:

275 MM Btu/hr, maximum process-generated fuel gas firing rate
Calculation of CO2 based on carbon balance for fuel gas (see nominal fuel gas speciation below)
0.007 lb/MM Btu, CH4 factor for petroleum fuel from 40 CFR 98, Subpart C, Table C-2
(converted from 0.003 kg/MM Btu for use with Eq. C-8b)
0.001 lb/MM Btu, N2O factor for petroleum fuel from 40 CFR 98, Subpart C, Table C-2
(converted from 0.0006 kg/MM Btu for use with Eq. C-8b)
8,760 hr/yr, hours of operation
Emission calculations below represent maximum emissions for each of the five furnaces

Fuel Gas Component	Molecular Weight (lb/lb mole)	Higher Heating Value (Btu/lb)	Max Firing Rate (lb/hr)	Annual Fuel Firing Rate (MM Btu/yr)	No. of Carbons per Molecule	Annual CO_2 Emissions (tons/yr)
Methane	16.04	23,900	4658.56	975,335	1	55,985.15
Ethane	30.07	22,336	4.76	931	2	61.03
Ethylene	28.10	21,651	108.64	20,605	2	1,490.52
Hydrogen	2.00	60,828	2644.40	1,409,077	0	0.00
Carbon Monoxide	28.01	4,346	119.37	4,545	1	821.50
Totals				2,410,493		58,358.20
Pollutants			**Emission Factor (lb/MM Btu)**	**Total Heating Value (MM Btu/yr)**		**Annual Emissions (tons/yr)**
CH_4			0.007	2,410,493		7.97
N_2O			0.001	2,410,493		1.59

Calculation methods:

Annual CO2 emissions (tons/yr) = fuel gas mass rate (lb/hr) x MW_{CO2} / MW_{VOC} x no. of carbons x 1 ton/2,000 lb x 8,760 hr/yr
Annual fuel gas emissions (tons/yr) = emission factor (lb/MM Btu) x annual fuel firing rate (MM Btu/yr) x 1 ton/2,000 lb

Occidental Chemical Corporation
January 2014

Ethane Cracking Furnace Nos. 1-5 - MSS Activities

EPN's CR-1-MSS, CR-2-MSS, CR-3-MSS, CR-4-MSS and CR-5-MSS

Estimated Emissions Based on Expected Coke Burn-Off

Basis:

Calculation of CO2 based on Equation Y-8 of 40 CFR 98.253 for coke burn-off
Calculation of CH4 based on Equation Y-9 of 40 CFR 98.253 for coke burn-off
(the CO2 estimate times the ration of CO2/CH4 default factors)
Calculation of N2O based on Equation Y-9 of 40 CFR 98.253 for coke burn-off
(the CO2 estimate times the ration of CO2/N2O default factors)
5,000 lb coke removed during each decoke event
0.94 default carbon content of coke per 40 CFR 98.253 Equation Y-8
102.04 kg CO2/MM Btu default CO2 factor for coke combustion from 40 CFR 98 Table C-1
0.011 kg CH4/MM Btu default CH4 factor for coke combustion from 40 CFR 98 Table C-2
0.0016 kg N2O/MM Btu default N2O factor for coke combustion from 40 CFR 98 Table C-2
48 hr/decoke event
36 decoke events/yr
Annual emission calculations below represent maximum emissions for all five furnaces

Pollutant	Coke Burn-Off (lb/decoke)	Coke Molecular Weight (lb/lb mole)	Annual Emissions (tons/yr)	Hourly Emissions (lb/hr)
CO_2	5,000	12.00	310.20	359.03
CH_4	na	na	0.033	0.039
N_2O	na	na	0.005	0.006

Emission comparisons:

Source of CO2 Emissions	Annual Emissions (tons/yr)	Hours of Operation (hr/event)	Hourly Emissions (lb/hr)	Comments
CO_2 from Coke Combustion	310	1,728	359	
CO_2 from Natural Gas	140,817	8,760	32,150	Worst-case hourly emissions
CO_2 from Process Fuel Gas	58,358	8,760	13,324	

Calculation methods:

Annual CO2 emissions (tons/yr) = coke mass rate (lb/event) x MW_{CO2} / MW_C x carbon content x no. of decoke events/yr x 1 ton/2,000 lb
Annual CH4 emissions (tons/yr) = CO2 emission rate (tons/yr) x default coke CH4 factor / default coke CO2 factor
Annual N2O emissions (tons/yr) = CO2 emission rate (tons/yr) x default coke N2O factor / default coke CO2 factor
Hourly emissions (lb/hr) = annual emissions (tons/yr) x 2,000 lb/ton x yr/no. of events (yr/event) x event/no. of hr (event/hr)

Conclusion:

Since hourly decoking CO2 emissions are less than hourly normal CO2 emissions, worst-case annual emissions do not include decoking contributions. The same is true for CH4 and N2O emissions.

Occidental Chemical Corporation
January 2014

CR Thermal Oxidizer Nos. 1 and 2

EPN's CR-6 and CR-7

Basis:

8.00 MM Btu/hr, core natural gas burner fuel firing rate
116.91 lb/MM Btu, CO2 factor for natural gas from 40 CFR 98, Subpart C, Table C-1 (converted from 53.02 kg/MM Btu for use with Eq. C-1b)
Calculation of CO2 based on carbon balance for process waste gas (see nominal process waste gas speciation below)
7.40 lb/hr CO2 contained in waste gas sent to the oxidizers
0.002 lb/MM Btu, CH4 factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.001 kg/MM Btu for use with Eq. C-8b)
0.0002 lb/MM Btu, N2O factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.0001 kg/MM Btu for use with Eq. C-8b)
0.007 lb/MM Btu, CH4 factor for petroleum fuel from 40 CFR 98, Subpart C, Table C-2 (converted from 0.003 kg/MM Btu for use with Eq. C-8b)
0.001 lb/MM Btu, N2O factor for petroleum fuel from 40 CFR 98, Subpart C, Table C-2 (converted from 0.0006 kg/MM Btu for use with Eq. C-8b)
8,760 hr/yr, hours of operation
Emission calculations below represent maximum emissions for each of the two thermal oxidizers

Pollutant	Molecular Weight (lb/lb mole)	Higher Heating Value (Btu/scf)	Higher Heating Value (Btu/lb)	Normal Venting (lb/hr)	Total Heating Value (MM Btu/yr)	No. of Carbons per Molecule	Annual CO_2 Emissions (tons/yr)
Hydrogen	2.00	321.0	60,830	27.73	14,777	0	0.00
Carbon Monoxide	28.00	321.1	4,346	0.72	27	1	4.96
Methane	16.04	1,011.5	23,900	230.30	48,217	1	2,767.68
Acetylene	26.04	1,475.8	21,479	1.13	213	2	16.75
Ethylene	28.06	1,603.0	21,651	442.60	83,944	2	6,081.03
Ethane	30.07	1,772.1	22,336	276.94	54,187	2	3,550.65
MAPD	18.90	1,038.0	20,815	2.91	531	3	89.10
Propylene	42.08	2,338.0	21,058	106.76	19,694	3	1,467.20
Propane	44.09	2,521.6	21,676	26.73	5,076	3	350.62
Butadienes	54.09	2,945.7	20,640	201.50	36,432	4	2,872.38
Butylenes	56.01	3,073.3	20,796	12.63	2,301	4	173.91
Butanes	58.12	3,268.4	21,312	16.69	3,116	4	221.42
C5's	72.15	4,017.0	21,101	815.62	150,764	5	10,895.56
C6-C8 Non-Aromatics	100.20	5,540.6	20,956	652.86	119,849	7	8,791.46
Benzene	78.11	3,749.1	18,190	746.49	118,949	6	11,052.80
Toluene	92.14	4,483.3	18,441	76.39	12,339	7	1,118.61
Xylene/Ethylene Benzene	106.16	5,218.1	18,629	7.78	1,270	8	113.03
Styrene	104.15	5,040.4	18,342	6.92	1,112	8	102.48
C9-204°C	128.30	7,012.2	20,714	9.71	1,762	9	131.31
204°C Plus	130.00	7,109.5	20,727	0.94	170	10	13.91
Totals					674,731		49,809.87
Pollutant				**Emission Factor (lb/MM Btu)**	**Total Heating Value (MM Btu/yr)**	**Hourly Emissions (lb/hr)**	**Annual Emissions (tons/yr)**
CO_2 - natural gas				116.91	70,080		4,096.49
CO_2 - waste gas combustion							49,809.87
CO_2 - process gas						7.40	32.41
CO_2 - total							53,938.77
CH_4 - natural gas				0.002	70,080		0.08
CH_4 - waste gas combustion				0.007	674,731		2.23
CH_4 - total							2.31
N_2O - natural gas				0.0002	70,080		0.01
N_2O - waste gas comb.				0.001	674,731		0.45
N_2O - total							0.45

Calculation methods:

Annual CO2 emissions (tons/yr) = natural gas emission factor (lb/MM Btu) x natural gas fuel firing rate (MM Btu/yr) x hours of operation (hr/yr) x 1 ton/2,000 lb + annual waste gas combustion-related CO2 (tons/yr) + process CO2 gas (lb/hr) x hours of operation (hr/yr) x 1 ton/2,000 lb
Annual CH4 and N2O emissions (tons/yr) = natural gas emission factor (lb/MM Btu) x natural gas fuel firing rate (MM Btu/yr) x hours of operation (hr/yr) x 1 ton/2,000 lb + petroleum fuel gas emission factor (lb/MM Btu) x total heating value of waste as (MM Btu/yr) x 1 ton/2,000 lb

Notes:

MAPD = Methyl Acetylene/Propadiene

Occidental Chemical Corporation
January 2014

CR High Pressure Flare

EPN CR-8

Basis:

80	scfh, natural gas input to a single flare pilot
0.001028	MM Btu/scf default natural gas heating value from 40 CFR 98, Subpart C, Table C-1
116.91	lb/MM Btu, CO2 factor for natural gas from 40 CFR 98, Subpart C, Table C-1 (converted from 53.02 kg/MM Btu for use with Eq. C-1)
0.002	lb/MM Btu, CH4 factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.001 kg/MM Btu for use with Eq. C-8)
0.0002	lb/MM Btu, N2O factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.0001 kg/MM Btu for use with Eq. C-8)
20	number of pilots
8,760	hr/yr, hours of operation

Pollutant	Emission Factor (lb/MM Btu)	Hourly Emissions (lb/hr)	Annual Emissions (tons/yr)
CO_2	116.91	192.29	842.24
CH_4	0.002	0.0036	0.016
N_2O	0.0002	0.00036	0.0016

Calculation methods:

Hourly emissions (lb/hr) = emission factor (lb/MM Btu) x gas input per pilot (scfh) x default heating value (MM Btu/scf) x no. of pilots
Annual emissions (tons/yr) = hourly emissions (lb/hr) x 1 ton/2,000 lb x 8,760 hr/yr

Occidental Chemical Corporation
January 2014

CR High Pressure Flare - MSS Activities

EPN's CR-8-MSS

Basis:

Calculation of CO2 based on carbon balance for process waste gas (see nominal process waste gas speciation below)
0.007 lb/MM Btu, CH4 factor for petroleum fuel from 40 CFR 98, Subpart C, Table C-2 (converted from 0.003 kg/MM Btu for use with Eq. C-8b)
0.001 lb/MM Btu, N2O factor for petroleum fuel from 40 CFR 98, Subpart C, Table C-2 (converted from 0.0006 kg/MM Btu for use with Eq. C-8b)
288 hr/yr, hours of start-up operation
16 hr/yr, hours of shutdown operation
It should be noted that the number of events, gas input mass rates and hours per event are provided for calculation purposes only; these parameters could change, but the annual emission rates will not be exceeded.

Start-up Emissions:

Pollutant	Molecular Weight (lb/lb mole)	Higher Heating Value (Btu/scf)	Higher Heating Value (Btu/lb)	Start-up Venting (lb/hr)	Total Heating Value (MM Btu/yr)	No. of Carbons per Molecule	Annual CO_2 Emissions (tons/yr)
Hydrogen	2.00	321.0	60,830	5,881.81	103,043	0	0.00
Carbon Monoxide	28.00	335.1	4,536	250.80	328	1	56.77
Carbon Dioxide	44.01	0.0	0	262.46	0	1	37.79
Hydrogen Sulfide	26.04	488.3	7,107	15.07	31	0	0.00
Methane	16.04	1,011.5	23,900	9,810.79	67,530	1	3,876.27
Acetylene	26.04	1,475.8	21,479	635.58	3,932	2	309.37
Ethylene	28.06	1,603.0	21,651	78,485.22	489,394	2	35,452.27
Ethane	30.07	1,772.1	22,336	52,649.74	338,684	2	22,192.52
MAPD	40.06	2,200.1	20,815	77.33	464	3	36.70
Propylene	40.08	2,226.9	21,058	1,998.59	12,121	3	948.05
Propane	44.09	2,521.6	21,676	461.78	2,883	3	199.13
Butadienes	54.09	2,945.7	20,640	2,156.44	12,819	4	1,010.63
Butylenes	56.10	3,078.2	20,796	299.09	1,791	4	135.15
Butanes	58.12	3,268.2	21,312	362.56	2,225	4	158.14
C5's	72.15	4,017.0	21,101	657.69	3,997	5	288.85
C6's Non-Aromatics	86.18	4,765.1	20,956	561.88	3,391	6	247.91
C7's Non-Aromatics	100.20	5,513.1	20,853	124.63	748	7	55.18
C8's Non-Aromatics	114.23	6,284.8	20,852	90.64	544	8	40.23
Benzene	78.11	3,748.9	18,190	1,110.23	5,816	6	540.47
Toluene	92.14	4,483.3	18,441	352.22	1,871	7	169.58
Xylene/ EB	106.16	5,218.1	18,629	148.94	799	8	71.13
Styrene	104.15	5,040.4	18,342	33.99	180	8	16.55
C9-204°C	128.30	7,012.2	20,714	151.25	902	9	67.24
204°C Plus	130.00	7,109.5	20,727	23.76	142	10	11.58
Totals					1,053,633		65,921.50
Pollutant				**Emission Factor (lb/MM Btu)**	**Total Heating Value (MM Btu/yr)**	**Hourly Emissions (lb/hr)**	**Annual Start-up Emissions (tons/yr)**
CH_4				0.007	1,053,633		3.48
N_2O				0.001	1,053,633		0.70

Continued on next page.

Occidental Chemical Corporation
January 2014

CR High Pressure Flare - MSS Activities (cont'd)

EPN's CR-8-MSS

Shutdown Emissions:

Pollutant	Molecular Weight (lb/lb mole)	Higher Heating Value (Btu/scf)	Higher Heating Value (Btu/lb)	Shutdown Venting (lb/hr)	Total Heating Value (MM Btu/yr)	No. of Carbons per Molecule	Annual CO_2 Emissions (tons/yr)
Hydrogen	2.00	321.0	60,830	3.82	4	0	0.00
Carbon Monoxide	28.00	335.1	4,536	3.26	0	1	0.04
Carbon Dioxide	44.01	0.0	0	0.00	0	1	0.00
Hydrogen Sulfide	26.04	488.3	7,107	0.00	0	0	0.00
Methane	16.04	1,011.5	23,900	6,150.98	2,352	1	135.01
Acetylene	26.04	1,475.8	21,479	0.00	0	2	0.00
Ethylene	28.06	1,603.0	21,651	46,676.73	16,170	2	1,171.34
Ethane	30.07	1,772.1	22,336	30,482.69	10,894	2	713.82
MAPD	40.06	2,200.1	20,815	58.53	19	3	1.54
Propylene	40.08	2,226.9	21,058	56,379.14	18,996	3	1,485.78
Propane	44.09	2,521.6	21,676	594.93	206	3	14.25
Butadienes	54.09	2,945.7	20,640	1,621.93	536	4	42.23
Butylenes	56.10	3,078.2	20,796	225.08	75	4	5.65
Butanes	58.12	3,268.2	21,312	273.07	93	4	6.62
C5's	72.15	4,017.0	21,101	411.92	139	5	10.05
C6's Non-Aromatics	86.18	4,765.1	20,956	324.98	109	6	7.97
C7's Non-Aromatics	100.20	5,513.1	20,853	65.57	22	7	1.61
C8's Non-Aromatics	114.23	6,284.8	20,852	38.08	13	8	0.94
Benzene	78.11	3,748.9	18,190	611.99	178	6	16.55
Toluene	92.14	4,483.3	18,441	162.16	48	7	4.34
Xylene/ EB	106.16	5,218.1	18,629	48.46	14	8	1.29
Styrene	104.15	5,040.4	18,342	9.85	3	8	0.27
C9-Plus	128.30	7,012.2	20,714	23.22	8	9	0.57
Totals				144,166.39	49,878		3,619.87
Pollutant				**Emission Factor (lb/MM Btu)**	**Total Heating Value (MM Btu/yr)**	**Hourly Emissions (lb/hr)**	**Annual Shutdown Emissions (tons/yr)**
CH_4				0.007	49,878		0.16
N_2O				0.001	49,878		0.03

Total MSS Emissions:

Pollutant					Annual Start-up Emissions (tons/yr)	Annual Shutdown Emissions (tons/yr)	Total Annual Emissions (tons/yr)
CO_2					65,921.50	3,619.87	69,541.37
CH_4					3.48	0.16	3.65
N_2O					0.70	0.03	0.73

Calculation methods:

Annual CO2 emissions (tons/yr) = vent gas (lb/hr) x MW_{CO2} / MW_{VOC} x no. of carbons x 1 ton/2,000 lb x 8,760 hr/yr
Annual CH4 and N2O emissions (tons/yr) = emission factor (lb/MM Btu) x fuel firing rate (MM Btu/hr) x 1 ton/2,000 lb x 8,760 hr/yr

Notes:

MAPD = Methyl Acetylene/Propadiene

Occidental Chemical Corporation
January 2014

CR Emergency Generator Diesel Engine
EPN CR-9

Basis:

105 gal/hr of diesel fired in 2,206 HP engine
0.138 MM Btu/gal diesel heating value
163.08 lb/MM Btu, CO2 factor for diesel from 40 CFR 98, Subpart C, Table C-1 (converted from 73.96 kg/MM Btu)
0.007 lb/MM Btu, CH4 factor for diesel from 40 CFR 98, Subpart C, Table C-2 (converted from 0.003 kg/MM Btu)
0.001 lb/MM Btu, N2O factor for diesel from 40 CFR 98, Subpart C, Table C-2 (converted from 0.0006 kg/MM Btu)
52 hr/yr, hours of operation

Engine	Pollutant	Emission Factor (lb/MM Btu)	Emissions (tons/yr)
CR-9	CO_2	163.08	61.4394
Emergency Generator	CH_4	0.007	0.0025
Diesel Engine	N_2O	0.001	0.0005

Calculation methods:

Annual emissions (tons/yr) = emission factor (lb/MM Btu) x diesel consumption (gal/hr) x heat content (MM Btu/gal) x hours of operation (hr/yr) x 1 ton/2,000 lb

Occidental Chemical Corporation
January 2014

CR Cooling Tower

EPN CR-11

Basis:

961,282 lb/hr make-up water
220 ppmw bicarbonate (HCO3) equivalent concentration
representing make-up water alkalinity
61 lb/lb mole, molecular weight of HCO3
one mole of CO2 released per mole of HCO3
44 lb/lb mole, molecular weight of CO2
8,760 hr/yr, hours of operation

Pollutant	HCO_3 Loading in Make-up Water (lb/hr)	CO_2 Hourly Emissions (lb/hr)	Annual CO_2 Emissions (tons/yr)
CO_2	211.48	152.54	668.14

Calculation methods:

HCO3 loading (lb/hr) = make-up water (lb/hr) x bicarbonate equivalent concentration (ppmw)
Hourly CO2 emissions (lb/hr) = HCO3 loading (lb/hr) x MW CO2 (lb/lb mole) x
1/MW HCO3 (lb/lb mole)
Annual CO2 emissions (tons/yr) = hourly emissions (lb/hr) x 1 ton/2,000 lb x 8,760 hr/yr

Occidental Chemical Corporation
January 2014

C3/C4 Hydrogenation Regeneration Vent - MSS Activities

EPN CR-12-MSS

Basis:

Calculation of CO2 based on Equation Y-8 of 40 CFR 98.253 for coke burn-off
Calculation of CH4 based on Equation Y-9 of 40 CFR 98.253 for coke burn-off
(the CO2 estimate times the ration of CO2/CH4 default factors)
Calculation of N2O based on Equation Y-10 of 40 CFR 98.253 for coke burn-off
(the CO2 estimate times the ration of CO2/N2O default factors)

3,600 lb coke removed during each decoke event
0.94 default carbon content of coke per 40 CFR 98.253 Equation Y-8
102.04 kg CO2/MM Btu default CO2 factor for coke combustion from 40 CFR 98 Table C-1
0.011 kg CH4/MM Btu default CH4 factor for coke combustion from 40 CFR 98 Table C-2
0.0016 kg N2O/MM Btu default N2O factor for coke combustion from 40 CFR 98 Table C-2
48 hr/decoke event
100 hr/yr, hours of operation per year

Pollutant	Coke Burn-Off (lb/decoke)	Coke Molecular Weight (lb/lb mole)	Annual Emissions (tons/yr)
CO_2	3,600	12.00	12.93
CH_4	na	na	0.001
N_2O	na	na	0.000

Calculation methods:

Annual CO2 emissions (tons/yr) = coke mass rate (lb/event) x MW_{CO2} / MW_C x carbon content x hr of decoke events/yr (hr/yr) x decoke event/hr (event/hr) x 1 ton/2,000 lb
Annual CH4 emissions (tons/yr) = CO2 emission rate (tons/yr) x default coke CH4 factor / default coke CO2 factor
Annual N2O emissions (tons/yr) = CO2 emission rate (tons/yr) x default coke N2O factor / default coke CO2 factor

Ethylene Plant Fugitive Emission Totals
CR Furnace Area Fugitives, CR-13

Constituents	Ethane Feed (Comp B): 4010 Pipeline Ethane Feed		Saturated C2 (Comp C): Nos. 1-5 Furnace Feeds; Feed Saturator Vapor		Furnace Outlet (Comp D): Nos. 1-5 Furnace Outlets		Quench Overhead (Comp E): Quench Column Liquid Gasoline		Quench Gasoline (Comp F): Quench Column Liquid Gasoline		Quench Water (Comp G): Feed Saturator Water; Quench Water; Process Water Treatment	
	Weight Fraction	**Emissions (lb/hr)**	**Weight Fraction**	**Emissions (lb/hr)**	**Weight Fraction**	**Emissions (lb/hr)**	**Weight Fraction**	**Emissions (lb/hr)**	**Weight Fraction**	**Emissions (lb/hr)**	**Weight Fraction**	**Emissions (lb/hr)**
	1.0000	**0.0783**	**1.0000**	**0.2038**	**1.0000**	**0.3586**	**1.0000**	**0.0179**	**1.0000**	**0.0336**	**1.0000**	**0.1261**
Hydrogen	0.000000	0.0000	0.000000	0.0000	0.269900	0.0968	0.339000	0.0061	0.000000	0.0000	0.000000	0.0000
Carbon Monoxide	0.000000	0.0000	0.000000	0.0000	0.000800	0.0003	0.001000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Dioxide	0.000100	0.0000	0.000100	0.0000	0.000300	0.0001	0.000300	0.0000	0.000000	0.0000	0.000000	0.0000
Hydrogen Sulfide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000
Methane	0.025000	0.0020	0.015000	0.0031	0.054500	0.0195	0.068400	0.0012	0.000000	0.0000	0.000000	0.0000
Acetylene	0.000000	0.0000	0.000000	0.0000	0.002300	0.0008	0.002800	0.0001	0.000000	0.0000	0.000000	0.0000
Ethylene	0.000000	0.0000	0.002000	0.0004	0.259300	0.0930	0.325800	0.0058	0.000000	0.0000	0.000100	0.0000
Ethane	0.949900	0.0744	0.633900	0.1292	0.161700	0.0580	0.203100	0.0036	0.000000	0.0000	0.000100	0.0000
Methyl Acetylene/Propadiene	0.000000	0.0000	0.000000	0.0000	0.000200	0.0001	0.000200	0.0000	0.000000	0.0000	0.000000	0.0000
Propylene	0.000000	0.0000	0.002000	0.0004	0.004600	0.0016	0.005800	0.0001	0.000000	0.0000	0.000000	0.0000
Propane	0.025000	0.0020	0.015000	0.0031	0.001000	0.0004	0.001200	0.0000	0.000000	0.0000	0.000000	0.0000
Butadienes	0.000000	0.0000	0.000000	0.0000	0.003700	0.0013	0.004700	0.0001	0.000500	0.0000	0.000000	0.0000
Butylenes	0.000000	0.0000	0.000000	0.0000	0.000500	0.0002	0.000600	0.0000	0.000100	0.0000	0.000000	0.0000
Butanes	0.000000	0.0000	0.000000	0.0000	0.000600	0.0002	0.000700	0.0000	0.000000	0.0000	0.000000	0.0000
C5's	0.000000	0.0000	0.000000	0.0000	0.000700	0.0003	0.001100	0.0000	0.135200	0.0045	0.000000	0.0000
C6-C8 Non-Aromatics	0.000000	0.0000	0.000000	0.0000	0.000600	0.0002	0.000900	0.0000	0.212600	0.0071	0.000000	0.0000
Benzene	0.000000	0.0000	0.000000	0.0000	0.001200	0.0004	0.001700	0.0000	0.498500	0.0167	0.000400	0.0001
Toluene	0.000000	0.0000	0.000000	0.0000	0.000200	0.0001	0.000200	0.0000	0.079400	0.0027	0.000100	0.0000
Xylene/ Ethyl Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.008600	0.0003	0.000000	0.0000
Styrene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.016200	0.0005	0.000000	0.0000
C9 - 204 C	0.000000	0.0000	0.000000	0.0000	0.000100	0.0000	0.000100	0.0000	0.030400	0.0010	0.000000	0.0000
204 - 288 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.010100	0.0003	0.000000	0.0000
288 C+	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.008400	0.0003	0.000000	0.0000
Water	0.000000	0.0000	0.332000	0.0677	0.237800	0.0853	0.042300	0.0008	0.000000	0.0000	0.999300	0.1260
Nitrogen	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
DMS/DMDS	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ammonia	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Total		0.0783		0.2038		0.3586		0.0179		0.0336		0.1261

Column Totals, EPN CR-13

Carbon Monoxide		0.0000		0.0000		0.0003		0.0000		0.0000		0.0000
Carbon Dioxide		0.0000		0.0000		0.0001		0.0000		0.0000		0.0000
Hydrogen Sulfide		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Methane		0.0020		0.0031		0.0195		0.0012		0.0000		0.0000
Ethane		0.0744		0.1292		0.0580		0.0036		0.0000		0.0000
Hydrogen, Water and Nitrogen		0.0000		0.0677		0.1820		0.0068		0.0000		0.1260
Ammonia		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Total VOC		0.0020		0.0039		0.0986		0.0062		0.0336		0.0001
Totals		0.0783		0.2038		0.3586		0.0179		0.0336		0.1261

Ethylene Plant Fugitive Emission Totals

CR Furnace Area Fugitives, CR-13 (cont'd)

Constituents	Off-Gas to Fuel (Comp V): Nos. 1-5 Furnace Fuel Systems; Fuel Gas Blend System		Natural Gas (Comp AD): NG Dist System		Dimethyl Sulfide (Comp AE): Dimethyl Sulfide System - Liquid Service (or Dimethyl Disulfide)		Dimethyl Sulfide Vapor (Comp AF): Dimethyl Sulfide System - Vapor Service (or Dimethyl Disulfide)		Wash Oil (Comp AG): Wash Oil - Liquid Service		Wash Oil Vapor (Comp AG): Wash Oil - Vapor Service	
	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)
	1.0000	0.7952	1.0000	0.1521	1.0000	0.0177	1.0000	0.0370	1.0000	0.0177	1.0000	0.0412
Hydrogen	0.819800	0.6519	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Monoxide	0.002700	0.0021	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Dioxide	0.000000	0.0000	0.012000	0.0018	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Hydrogen Sulfide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Methane	0.175000	0.1392	0.945000	0.1437	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Acetylene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethylene	0.002400	0.0019	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethane	0.000100	0.0001	0.032000	0.0049	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Methyl Acetylene/Propadiene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Propylene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Propane	0.000000	0.0000	0.008000	0.0012	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Butadienes	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Butylenes	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Butanes	0.000000	0.0000	0.000500	0.0001	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C5's	0.000000	0.0000	0.000400	0.0001	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C6-C8 Non-Aromatics	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Toluene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Xylene/ Ethyl Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Styrene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C9 - 204 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	1.000000	0.0177	0.007000	0.0003
204 - 288 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
288 C+	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Water	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Nitrogen	0.000000	0.0000	0.002000	0.0003	0.000000	0.0000	0.360000	0.0133	0.000000	0.0000	0.993000	0.0409
DMS/DMDS	0.000000	0.0000	0.000000	0.0000	1.000000	0.0177	0.640000	0.0237	0.000000	0.0000	0.000000	0.0000
Ammonia	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Total		0.7952		0.1521		0.0177		0.0370		0.0177		0.0412

Column Totals, EPN CR-13

Carbon Monoxide		0.0021		0.0000		0.0000		0.0000		0.0000		0.0000
Carbon Dioxide		0.0000		0.0018		0.0000		0.0000		0.0000		0.0000
Hydrogen Sulfide		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Methane		0.1392		0.1437		0.0000		0.0000		0.0000		0.0000
Ethane		0.0001		0.0049		0.0000		0.0000		0.0000		0.0000
Hydrogen, Water and Nitrogen		0.6519		0.0003		0.0000		0.0133		0.0000		0.0409
Ammonia		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Total VOC		0.0019		0.0014		0.0177		0.0237		0.0177		0.0003
Totals		0.7952		0.1521		0.0177		0.0370		0.0177		0.0412

Ethylene Plant Fugitive Emission Totals
CR Furnace Area Fugitives, CR-13 (cont'd)

Constituents	Ammonia (Comp XX): Ammonia Systems		Propylene Refrigeration (Comp AB): Propylene Refrigeration		De-Butanizer Overhead (Comp Y): De-Butanizer Overhead		De-Butanizer Bottoms (Comp W): De-Butanizer Bottoms - Liquid Service	
	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)
	1.0000	**0.0318**	**1.0000**	**0.0280**	**1.0000**	**0.0618**	**1.0000**	**0.0475**
Hydrogen	0.0000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Monoxide	0.0000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Dioxide	0.0000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Hydrogen Sulfide	0.0000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Methane	0.0000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Acetylene	0.0000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethylene	0.0000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethane	0.0000	0.0000	0.000000	0.0000	0.000200	0.0000	0.000000	0.0000
Methyl Acetylene/Propadiene	0.0000	0.0000	0.000000	0.0000	0.018400	0.0011	0.000000	0.0000
Propylene	0.0000	0.0000	0.980000	0.0275	0.377700	0.0233	0.000000	0.0000
Propane	0.0000	0.0000	0.020000	0.0006	0.103000	0.0064	0.000000	0.0000
Butadienes	0.0000	0.0000	0.000000	0.0000	0.371900	0.0230	0.000400	0.0000
Butylenes	0.0000	0.0000	0.000000	0.0000	0.050100	0.0031	0.000100	0.0000
Butanes	0.0000	0.0000	0.000000	0.0000	0.058700	0.0036	0.000100	0.0000
C5's	0.0000	0.0000	0.000000	0.0000	0.019100	0.0012	0.235800	0.0112
C6-C8 Non-Aromatics	0.0000	0.0000	0.000000	0.0000	0.000400	0.0000	0.243600	0.0116
Benzene	0.0000	0.0000	0.000000	0.0000	0.000500	0.0000	0.431300	0.0205
Toluene	0.0000	0.0000	0.000000	0.0000	0.000000	0.0000	0.057400	0.0027
Xylene/ Ethyl Benzene	0.0000	0.0000	0.000000	0.0000	0.000000	0.0000	0.005500	0.0003
Styrene	0.0000	0.0000	0.000000	0.0000	0.000000	0.0000	0.010000	0.0005
C9 - 204 C	0.0000	0.0000	0.000000	0.0000	0.000000	0.0000	0.014600	0.0007
204 - 288 C	0.0000	0.0000	0.000000	0.0000	0.000000	0.0000	0.001200	0.0001
288 C+	0.0000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Water	0.0000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Nitrogen	0.0000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
DMS/DMDS	0.0000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ammonia	1.0000	0.0318	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Total		0.0318		0.0280		0.0618		0.0475

Column Totals, EPN CR-13

Carbon Monoxide		0.0000		0.0000		0.0000		0.0000
Carbon Dioxide		0.0000		0.0000		0.0000		0.0000
Hydrogen Sulfide		0.0000		0.0000		0.0000		0.0000
Methane		0.0000		0.0000		0.0000		0.0000
Ethane		0.0000		0.0000		0.0000		0.0000
Hydrogen, Water and Nitrogen		0.0000		0.0000		0.0000		0.0000
Ammonia		0.0318		0.0000		0.0000		0.0000
Total VOC		0.0000		0.0280		0.0617		0.0475
Totals		0.0318		0.0280		0.0618		0.0475

Ethylene Plant Fugitive Emission Totals
CR Charge Gas Area Fugitives, CR-14

Constituents	Quench Overhead (Comp E): Charge Gas Compression and Chilling - Vapor Service		Charge Gas Liquid (Comp H): Charge Gas Compression and Chilling - Liquid Service		Quench Water (Comp G): Caustic Tower Liquid		De-Butanizer Bottoms (Comp W): Caustic Gasoline Washing; Emergency Relief Header - Liquid Service		Natural Gas (Comp AD): Emergency Relief Header - Vapor Service		Propylene Refrigeration (Comp AB): Propylene Refrigeration		Binary Refrigeration (Comp AC): Binary Refrigeration	
	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)
	1.0000	**0.3033**	**1.0000**	**0.0318**	**1.0000**	**0.0222**	**1.0000**	**0.0780**	**1.0000**	**0.0803**	**1.0000**	**0.3835**	**1.0000**	**0.3890**
Hydrogen	0.339000	0.1028	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.001000	0.0004
Carbon Monoxide	0.001000	0.0003	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Dioxide	0.000300	0.0001	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.012000	0.0010	0.000000	0.0000	0.000000	0.0000
Hydrogen Sulfide	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Methane	0.068400	0.0207	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.945000	0.0758	0.000000	0.0000	0.340000	0.1323
Acetylene	0.002800	0.0008	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethylene	0.325800	0.0988	0.000100	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.659000	0.2563
Ethane	0.203100	0.0616	0.000100	0.0000	0.000100	0.0000	0.000000	0.0000	0.032000	0.0026	0.000000	0.0000	0.000000	0.0000
Methyl Acetylene/Propadiene	0.000200	0.0001	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Propylene	0.005800	0.0018	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.980000	0.3758	0.000000	0.0000
Propane	0.001200	0.0004	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.008000	0.0006	0.020000	0.0077	0.000000	0.0000
Butadienes	0.004700	0.0014	0.000000	0.0000	0.000000	0.0000	0.000400	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Butylenes	0.000600	0.0002	0.000000	0.0000	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Butanes	0.000700	0.0002	0.000000	0.0000	0.000000	0.0000	0.000100	0.0000	0.000500	0.0000	0.000000	0.0000	0.000000	0.0000
C5's	0.001100	0.0003	0.000000	0.0000	0.000000	0.0000	0.235800	0.0184	0.000400	0.0000	0.000000	0.0000	0.000000	0.0000
C6-C8 Non-Aromatics	0.000900	0.0003	0.000100	0.0000	0.000000	0.0000	0.243600	0.0190	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000
Benzene	0.001700	0.0005	0.000300	0.0000	0.000400	0.0000	0.431300	0.0336	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Toluene	0.000200	0.0001	0.000100	0.0000	0.000100	0.0000	0.057400	0.0045	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Xylene/ Ethyl Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.005500	0.0004	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Styrene	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000	0.010000	0.0008	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C9 - 204 C	0.000100	0.0000	0.000400	0.0000	0.000000	0.0000	0.014600	0.0011	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
204 - 288 C	0.000000	0.0000	0.000400	0.0000	0.000000	0.0000	0.001200	0.0001	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
288 C+	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Water	0.042300	0.0128	0.998300	0.0317	0.999300	0.0222	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Nitrogen	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.002000	0.0002	0.000000	0.0000	0.000000	0.0000
DMS/DMDS	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ammonia	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Total		0.3033		0.0318		0.0222		0.0780		0.0803		0.3835		0.3890

Column Totals, EPN CR-14

Carbon Monoxide		0.0003		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Carbon Dioxide		0.0001		0.0000		0.0000		0.0000		0.0010		0.0000		0.0000
Hydrogen Sulfide		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Methane		0.0207		0.0000		0.0000		0.0000		0.0758		0.0000		0.1323
Ethane		0.0616		0.0000		0.0000		0.0000		0.0026		0.0000		0.0000
Hydrogen, Water and Nitrogen		0.1156		0.0317		0.0222		0.0000		0.0002		0.0000		0.0004
Ammonia		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Total VOC		0.1049		0.0001		0.0000		0.0780		0.0007		0.3835		0.2563
Totals		0.3033		0.0318		0.0222		0.0780		0.0803		0.3835		0.3890

Ethylene Plant Fugitive Emission Totals
CR Recovery Area Fugitives, CR-15

Constituents	Quench Overhead (Comp E): Charge Gas Drying - Vapor Service		Charge Gas Liquid (Comp H): Charge Gas Drying; Dryer Regeneration - All Liquid Service		Hydrogen Off-Gas (Comp N): Dryer Regeneration - Vapor Service		De-Methanizer Feed Vapor (Comp L): De-Methanizer Feed System - Vapor Service		De-Methanizer Liquid Feed (Comp M): De-Methanizer Feed System - Liquid Service		De-Methanizer Overhead Liquids (Comp O): De-Methanizer Overhead and Reflux	
	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)
	1.0000	**0.1554**	**1.0000**	**0.0054**	**1.0000**	**0.0739**	**1.0000**	**0.0717**	**1.0000**	**0.0225**	**1.0000**	**0.0598**
Hydrogen	0.339000	0.0527	0.000000	0.0000	0.842500	0.0623	0.358300	0.0257	0.004800	0.0001	0.002500	0.0001
Carbon Monoxide	0.001000	0.0002	0.000000	0.0000	0.002500	0.0002	0.001100	0.0001	0.000300	0.0000	0.001200	0.0001
Carbon Dioxide	0.000300	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Hydrogen Sulfide	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Methane	0.068400	0.0106	0.000000	0.0000	0.152600	0.0113	0.072900	0.0052	0.143700	0.0032	0.936200	0.0560
Acetylene	0.002800	0.0004	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethylene	0.325800	0.0506	0.000100	0.0000	0.002300	0.0002	0.349300	0.0250	0.644900	0.0145	0.057600	0.0034
Ethane	0.203100	0.0316	0.000100	0.0000	0.000100	0.0000	0.217200	0.0156	0.206200	0.0046	0.002500	0.0001
Methyl Acetylene/Propadiene	0.000200	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Propylene	0.005800	0.0009	0.000000	0.0000	0.000000	0.0000	0.001100	0.0001	0.000100	0.0000	0.000000	0.0000
Propane	0.001200	0.0002	0.000000	0.0000	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000
Butadienes	0.004700	0.0007	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Butylenes	0.000600	0.0001	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Butanes	0.000700	0.0001	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C5's	0.001100	0.0002	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C6-C8 Non-Aromatics	0.000900	0.0001	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Benzene	0.001700	0.0003	0.000300	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Toluene	0.000200	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Xylene/ Ethyl Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Styrene	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C9 - 204 C	0.000100	0.0000	0.000400	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
204 - 288 C	0.000000	0.0000	0.000400	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
288 C+	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Water	0.042300	0.0066	0.998300	0.0054	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Nitrogen	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
DMS/DMDS	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ammonia	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Total		0.1554		0.0054		0.0739		0.0717		0.0225		0.0598

Column Totals, EPN CR-15

Carbon Monoxide		0.0002		0.0000		0.0002		0.0001		0.0000		0.0001
Carbon Dioxide		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Hydrogen Sulfide		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Methane		0.0106		0.0000		0.0113		0.0052		0.0032		0.0560
Ethane		0.0316		0.0000		0.0000		0.0156		0.0046		0.0001
Hydrogen, Water and Nitrogen		0.0592		0.0054		0.0623		0.0257		0.0001		0.0001
Ammonia		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Total VOC		0.0537		0.0000		0.0002		0.0251		0.0145		0.0034
Totals		0.1554		0.0054		0.0739		0.0717		0.0225		0.0598

Ethylene Plant Fugitive Emission Totals
CR Recovery Area Fugitives, CR-15 (cont'd)

Constituents	De-Methanizer Bottoms (Comp P): De-Methanizer Bottoms		AC Reactor Feed (Comp J): De-Ethanizer Overhead		De-Ethanizer Reflux (Comp K): De-Ethanizer Reflux		De-Ethanizer Bottoms (Comp I): De-Ethanizer Bottoms		Ethylene Product (Comp Q): Ethylene Fractionator Overhead		Ethylene Side Reboiler (Comp S): Ethylene Fractionator Side Reboiler	
	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)
	1.0000	**0.0575**	**1.0000**	**0.3122**	**1.0000**	**0.0268**	**1.0000**	**0.0498**	**1.0000**	**0.7779**	**1.0000**	**0.0274**
Hydrogen	0.000000	0.0000	0.330600	0.1032	0.004000	0.0001	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Monoxide	0.000000	0.0000	0.001000	0.0003	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Dioxide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Hydrogen Sulfide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Methane	0.000300	0.0000	0.067700	0.0211	0.013600	0.0004	0.000000	0.0000	0.000500	0.0004	0.000000	0.0000
Acetylene	0.000000	0.0000	0.002800	0.0009	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethylene	0.614600	0.0353	0.355200	0.1109	0.458200	0.0123	0.000100	0.0000	0.999000	0.7771	0.591100	0.0162
Ethane	0.383000	0.0220	0.240400	0.0751	0.509500	0.0137	0.000000	0.0000	0.000500	0.0004	0.408000	0.0112
Methyl Acetylene/Propadiene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.013900	0.0007	0.000000	0.0000	0.000000	0.0000
Propylene	0.001900	0.0001	0.002100	0.0007	0.012900	0.0003	0.284400	0.0142	0.000000	0.0000	0.000800	0.0000
Propane	0.000200	0.0000	0.000200	0.0001	0.001700	0.0000	0.091800	0.0046	0.000000	0.0000	0.000100	0.0000
Butadienes	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.280100	0.0140	0.000000	0.0000	0.000000	0.0000
Butylenes	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.037700	0.0019	0.000000	0.0000	0.000000	0.0000
Butanes	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.049900	0.0025	0.000000	0.0000	0.000000	0.0000
C5's	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.066600	0.0033	0.000000	0.0000	0.000000	0.0000
C6-C8 Non-Aromatics	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.054800	0.0027	0.000000	0.0000	0.000000	0.0000
Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.100100	0.0050	0.000000	0.0000	0.000000	0.0000
Toluene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.013300	0.0007	0.000000	0.0000	0.000000	0.0000
Xylene/ Ethyl Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.001300	0.0001	0.000000	0.0000	0.000000	0.0000
Styrene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.002300	0.0001	0.000000	0.0000	0.000000	0.0000
C9 - 204 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.003400	0.0002	0.000000	0.0000	0.000000	0.0000
204 - 288 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000300	0.0000	0.000000	0.0000	0.000000	0.0000
288 C+	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Water	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Nitrogen	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
DMS/DMDS	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ammonia	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Total		0.0575		0.3122		0.0268		0.0498		0.7779		0.0274

Column Totals, EPN CR-15

Carbon Monoxide		0.0000		0.0003		0.0000		0.0000		0.0000		0.0000
Carbon Dioxide		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Hydrogen Sulfide		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Methane		0.0000		0.0211		0.0004		0.0000		0.0004		0.0000
Ethane		0.0220		0.0751		0.0137		0.0000		0.0004		0.0112
Hydrogen, Water and Nitrogen		0.0000		0.1032		0.0001		0.0000		0.0000		0.0000
Ammonia		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Total VOC		0.0354		0.1125		0.0127		0.0498		0.7771		0.0162
Totals		0.0575		0.3122		0.0268		0.0498		0.7779		0.0274

Ethylene Plant Fugitive Emission Totals
CR Recovery Area Fugitives, CR-15 (cont'd)

Constituents	Ethane Recycle (Comp R): Ethylene Fractionator Bottoms; Recycle Ethane Storage		Propylene Refrigeration (Comp AB): Propylene Refrigeration		Binary Refrigeration (Comp AC): Binary Refrigeration	
	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)
	1.0000	**0.0967**	**1.0000**	**0.2191**	**1.0000**	**0.0436**
Hydrogen	0.000000	0.0000	0.000000	0.0000	0.001000	0.0000
Carbon Monoxide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Dioxide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Hydrogen Sulfide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Methane	0.000000	0.0000	0.000000	0.0000	0.340000	0.0148
Acetylene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethylene	0.005000	0.0005	0.000000	0.0000	0.659000	0.0287
Ethane	0.989600	0.0957	0.000000	0.0000	0.000000	0.0000
Methyl Acetylene/Propadiene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Propylene	0.004900	0.0005	0.980000	0.2147	0.000000	0.0000
Propane	0.000500	0.0000	0.020000	0.0044	0.000000	0.0000
Butadienes	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Butylenes	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Butanes	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C5's	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C6-C8 Non-Aromatics	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Toluene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Xylene/ Ethyl Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Styrene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C9 - 204 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
204 - 288 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
288 C+	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Water	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Nitrogen	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
DMS/DMDS	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ammonia	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Total		0.0967		0.2191		0.0436

Column Totals, EPN CR-15

Carbon Monoxide		0.0000		0.0000		0.0000
Carbon Dioxide		0.0000		0.0000		0.0000
Hydrogen Sulfide		0.0000		0.0000		0.0000
Methane		0.0000		0.0000		0.0148
Ethane		0.0957		0.0000		0.0000
Hydrogen, Water and Nitrogen		0.0000		0.0000		0.0000
Ammonia		0.0000		0.0000		0.0000
Total VOC		0.0010		0.2191		0.0287
Totals		0.0967		0.2191		0.0436

Ethylene Plant Fugitive Emission Totals

CR C3+ Area Fugitives, CR-16

Constituents	Hydrogen Off-Gas (Comp N): Hydrogen Compressor Nos. 1 and 2; Hydrogen PSA		PSA Off-Gas (Comp U): Hydrogen PSA Off-Gas Blend		De-Butanizer Bottoms (Comp W): Decommissioning - Liquid Service		Hydro C3-4 (Comp Z): Hydrogenation Reactor - Liquid Service		Hydro C3-4 Vapor (Comp AA): Hydrogenation Reactor - Vapor Service	
	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)
	1.0000	**0.2978**	**1.0000**	**0.0359**	**1.0000**	**0.0081**	**1.0000**	**0.0306**	**1.0000**	**0.1140**
Hydrogen	0.842500	0.2509	0.616300	0.0221	0.000000	0.0000	0.007500	0.0002	0.419200	0.0478
Carbon Monoxide	0.002500	0.0007	0.006000	0.0002	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Dioxide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Hydrogen Sulfide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Methane	0.152600	0.0454	0.371900	0.0134	0.000000	0.0000	0.000100	0.0000	0.000800	0.0001
Acetylene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethylene	0.002300	0.0007	0.005600	0.0002	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethane	0.000100	0.0000	0.000200	0.0000	0.000000	0.0000	0.000200	0.0000	0.000400	0.0000
Methyl Acetylene/Propadiene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Propylene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Propane	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.484700	0.0148	0.429900	0.0490
Butadienes	0.000000	0.0000	0.000000	0.0000	0.000400	0.0000	0.000000	0.0000	0.000000	0.0000
Butylenes	0.000000	0.0000	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000
Butanes	0.000000	0.0000	0.000000	0.0000	0.000100	0.0000	0.486900	0.0149	0.147500	0.0168
C5's	0.000000	0.0000	0.000000	0.0000	0.235800	0.0019	0.019700	0.0006	0.002200	0.0003
C6-C8 Non-Aromatics	0.000000	0.0000	0.000000	0.0000	0.243600	0.0020	0.000400	0.0000	0.000000	0.0000
Benzene	0.000000	0.0000	0.000000	0.0000	0.431300	0.0035	0.000500	0.0000	0.000000	0.0000
Toluene	0.000000	0.0000	0.000000	0.0000	0.057400	0.0005	0.000000	0.0000	0.000000	0.0000
Xylene/ Ethyl Benzene	0.000000	0.0000	0.000000	0.0000	0.005500	0.0000	0.000000	0.0000	0.000000	0.0000
Styrene	0.000000	0.0000	0.000000	0.0000	0.010000	0.0001	0.000000	0.0000	0.000000	0.0000
C9 - 204 C	0.000000	0.0000	0.000000	0.0000	0.014600	0.0001	0.000000	0.0000	0.000000	0.0000
204 - 288 C	0.000000	0.0000	0.000000	0.0000	0.001200	0.0000	0.000000	0.0000	0.000000	0.0000
288 C+	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Water	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Nitrogen	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
DMS/DMDS	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ammonia	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Total		0.2978		0.0359		0.0081		0.0306		0.1140

Column Totals, EPN CR-16

Carbon Monoxide		0.0007		0.0002		0.0000		0.0000		0.0000
Carbon Dioxide		0.0000		0.0000		0.0000		0.0000		0.0000
Hydrogen Sulfide		0.0000		0.0000		0.0000		0.0000		0.0000
Methane		0.0454		0.0134		0.0000		0.0000		0.0001
Ethane		0.0000		0.0000		0.0000		0.0000		0.0000
Hydrogen, Water and Nitrogen		0.2509		0.0221		0.0000		0.0002		0.0478
Ammonia		0.0000		0.0000		0.0000		0.0000		0.0000
Total VOC		0.0007		0.0002		0.0081		0.0304		0.0661
Totals		0.2978		0.0359		0.0081		0.0306		0.1140

Ethylene Plant Fugitive Emission Totals
CR C3+ Area Fugitives, CR-16 (cont'd)

Constituents	Py-Gas Storage Vapor (Comp X): Decommissioning; Spent Caustic and WAO - All Vapor Service		Quench Water (Comp G): Spent NaOH Storage and WAO - Liquid Service		Propylene Refrigeration (Comp AB): Propylene Refrigeration	
	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)
	1.0000	**0.2018**	**1.0000**	**0.0375**	**1.0000**	**0.0280**
Hydrogen	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Monoxide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Dioxide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Hydrogen Sulfide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Methane	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Acetylene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethylene	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000
Ethane	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000
Methyl Acetylene/Propadiene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Propylene	0.000000	0.0000	0.000000	0.0000	0.980000	0.0275
Propane	0.000000	0.0000	0.000000	0.0000	0.020000	0.0006
Butadienes	0.032900	0.0066	0.000000	0.0000	0.000000	0.0000
Butylenes	0.000400	0.0001	0.000000	0.0000	0.000000	0.0000
Butanes	0.000300	0.0001	0.000000	0.0000	0.000000	0.0000
C5's	0.180900	0.0365	0.000000	0.0000	0.000000	0.0000
C6-C8 Non-Aromatics	0.078800	0.0159	0.000000	0.0000	0.000000	0.0000
Benzene	0.110000	0.0222	0.000400	0.0000	0.000000	0.0000
Toluene	0.008200	0.0017	0.000100	0.0000	0.000000	0.0000
Xylene/ Ethyl Benzene	0.000700	0.0001	0.000000	0.0000	0.000000	0.0000
Styrene	0.000300	0.0001	0.000000	0.0000	0.000000	0.0000
C9 - 204 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
204 - 288 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
288 C+	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Water	0.000000	0.0000	0.999300	0.0375	0.000000	0.0000
Nitrogen	0.587500	0.1185	0.000000	0.0000	0.000000	0.0000
DMS/DMDS	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ammonia	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Total		0.2018		0.0375		0.0280

Column Totals, EPN CR-16

Carbon Monoxide		0.0000		0.0000		0.0000
Carbon Dioxide		0.0000		0.0000		0.0000
Hydrogen Sulfide		0.0000		0.0000		0.0000
Methane		0.0000		0.0000		0.0000
Ethane		0.0000		0.0000		0.0000
Hydrogen, Water and Nitrogen		0.1185		0.0375		0.0000
Ammonia		0.0000		0.0000		0.0000
Total VOC		0.0832		0.0000		0.0280
Totals		0.2018		0.0375		0.0280

Occidental Chemical Corporation
January 2014

CR Recovery Area Fugitives - Example Fugitive Calculations

EPN CR-15

Binary Refrigeration (Comp AC)

These fugitive components are associated with the Ethylene Plant. Emissions are controlled using the TCEQ's 28MID program with quarterly monitoring of flanges and connectors.

Basis:

Emission factors are taken from the TCEQ's fugitive guidance document for average SOCMI speciation

Area	Component	Component Count	Emission Factor, lb/hr-comp	Efficiency, %	Fugitive Losses, lb/hr	Fugitive Losses, tons/yr
Equipment in VOC Service	VAL - G/V	40	0.0132	97	0.0158	0.0694
	VAL - G/V exempt		0.0132	0		
	VAL - LL	44	0.0089	97	0.0117	0.0515
	VAL - LL exempt		0.0089	0		
	VAL - HL		0.0005	0		
	PS - LL - MS		0.0439	100		
	PS - LL		0.0439	93		
	PS - HL - MS		0.019	100		
	PS - HL		0.019	0		
	FL - G/V quarterly	120	0.0039	97	0.0140	0.0615
	FL - G/V annual		0.0039	75		
	FL - G/V weekly		0.0039	30		
	FL - G/V exempt		0.0039	0		
	FL - LL quarterly	132	0.0005	97	0.0020	0.0087
	FL - LL annual		0.0005	75		
	FL - LL weekly		0.0005	30		
	FL - LL exempt		0.0005	0		
	FL - HL		0.00007	30		
	PRV		0.2293	97		
	CS - BS		0.5027	100		
	AS - LL/V		0.0439	100		
Total		**336**			**0.0436**	**0.1910**

Calculations Methods:

Hourly Emissions = (component count)(emission factor)(efficiency)

Annual Emissions = (component count)(emission factor)(efficiency)(8,760 hr/yr)(ton/2,000 lb)

Legend:

VAL - G/V	Valves in Gas/Vapor Service
VAL - G/V exempt	Valves in Gas/Vapor Service that are Difficult or Unsafe to Monitor
VAL - LL	Valves in Light Liquid Service
VAL - LL exempt	Valves in Light Liquid Service that are Difficult or Unsafe to Monitor
VAL - HL	Valves in Heavy Liquid Service
PS - LL - MS	Pump Seals in Light Liquid Service w/Mechanical Seal and Barrier Fluid
PS - LL	Pump Seals in Light Liquid Service
PS - HL - MS	Pump Seals in Heavy Liquid Service w/Mechanical Seal and Barrier Fluid
PS - HL	Pump Seals in Heavy Liquid Service
FL - G/V quarterly	Flanges/Connectors in Gas/Vapor Service Subject to Quarterly Monitoring
FL - G/V annual	Flanges/Connectors in Gas/Vapor Service Subject to Annual Monitoring
FL - G/V weekly	Flanges/Connectors in Gas/Vapor Service Subject to Weekly Physical Inspection
FL - G/V exempt	Flanges/Connectors in Gas/Vapor Service that are Difficult or Unsafe to Monitor
FL - LL quarterly	Flanges/Connectors in Light Liquid Service Subject to Quarterly Monitoring
FL - LL annual	Flanges/Connectors in Light Liquid Service Subject to Annual Monitoring
FL - LL weekly	Flanges/Connectors in Light Liquid Subject to Weekly Physical Inspection
FL - LL exempt	Flanges/Connectors in Light Liquid Service that are Difficult or Unsafe to Monitor
FL - HL	Flanges/Connectors in Heavy Liquid Service
PRV	Pressure Relief Valves (w/ Rupture Disks, Vented to a Control Device, or Relieves Thermally)
CS - BS	Compressor/Blower Seals with Barrier Seal
AS - LL/V	Agitator Seals in Light Liquid or Vapor Service w/Barrier Fluid

Ethylene Plant Fugitive Emissions Summary
CR Furnace Area Fugitives, CR-13; Column Totals

Constituents, Column Totals for EPN CR-13	Ethane Feed (Comp B)	Saturated C2 (Comp C)	Furnace Outlet (Comp D)	Quench Overhead (Comp E)	Quench Gasoline (Comp F)	Quench Water (Comp G)	Off-Gas to Fuel (Comp V)	Natural Gas (Comp AD)	Dimethyl Sulfide/Dimethyl Disulfide (Comp AE)	Dimethyl Sulfide/Dimethyl Disulfide Vapor (Comp AF)	Wash Oil (Comp AG)	Wash Oil Vapor (Comp AG)	Ammonia (Comp XX)	Propylene Refrigeration (Comp AB)	De-Butanizer Overhead (Comp Y)	De-Butanizer Bottoms (Comp W)	EPN CR-13 Total	
	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (tons/yr)
Carbon Monoxide	0.0000	0.0000	0.0003	0.0000	0.0000	0.0000	0.0021	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0025	0.0107
Carbon Dioxide	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0018	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0020	0.0086
Hydrogen Sulfide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Methane	0.0020	0.0031	0.0195	0.0012	0.0000	0.0000	0.1392	0.1437	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3086	1.3518
Ethane	0.0744	0.1292	0.0580	0.0036	0.0000	0.0000	0.0001	0.0049	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2702	1.1835
Hydrogen, Water and Nitrogen	0.0000	0.0677	0.1820	0.0068	0.0000	0.1260	0.6519	0.0003	0.0000	0.0133	0.0000	0.0409	0.0000	0.0000	0.0000	0.0000	1.0890	4.7697
Ammonia	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0318	0.0000	0.0000	0.0000	0.0318	0.1393
Total VOC	0.0020	0.0039	0.0986	0.0062	0.0336	0.0001	0.0019	0.0014	0.0177	0.0237	0.0177	0.0003	0.0000	0.0280	0.0617	0.0475	0.3442	1.5078
Totals	0.0783	0.2038	0.3586	0.0179	0.0336	0.1261	0.7952	0.1521	0.0177	0.0370	0.0177	0.0412	0.0318	0.0280	0.0618	0.0475	2.0483	8.9714

Ethylene Plant Fugitive Emissions Summary
CR Charge Gas Area Fugitives, CR-14; Column Totals

Constituents	Quench Overhead (Comp E)	Charge Gas Liquid (Comp H)	Quench Water (Comp G)	De-Butanizer Bottoms (Comp W)	Natural Gas (Comp AD)	Propylene Refrigeration (Comp AB)	Binary Refrigeration (Comp AC)	EPN CR-14 Total	
	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (tons/yr)
Carbon Monoxide	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0003	0.0013
Carbon Dioxide	0.0001	0.0000	0.0000	0.0000	0.0010	0.0000	0.0000	0.0011	0.0046
Hydrogen Sulfide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
Methane	0.0207	0.0000	0.0000	0.0000	0.0758	0.0000	0.1323	0.2288	1.0023
Ethane	0.0616	0.0000	0.0000	0.0000	0.0026	0.0000	0.0000	0.0642	0.2811
Hydrogen, Water and Nitrogen	0.1156	0.0317	0.0222	0.0000	0.0002	0.0000	0.0004	0.1701	0.7451
Ammonia	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total VOC	0.1049	0.0001	0.0000	0.0780	0.0007	0.3835	0.2563	0.8234	3.6066
Totals	0.3033	0.0318	0.0222	0.0780	0.0803	0.3835	0.3890	1.2879	5.6412

Ethylene Plant Fugitive Emissions Summary
CR Recovery Area Fugitives, CR-15; Column Totals

Constituents	Quench Overhead (Comp E)	Charge Gas Liquid (Comp H)	Hydrogen Off-Gas (Comp N)	De-Methanizer Feed Vapor (Comp L)	De-Methanizer Liquid Feed (Comp M)	De-Methanizer Overhead Liquids (Comp O)	De-Methanizer Bottoms (Comp P)	AC Reactor Feed (Comp J)	De-Ethanizer Reflux (Comp K)	De-Ethanizer Bottoms (Comp I)	Ethylene Product (Comp Q)	Ethylene Side Reboiler (Comp S)	Ethane Recycle (Comp R)	Propylene Refrigera-tion (Comp AB)	Binary Refrigera-tion (Comp AC)	EPN CR-15 Total	
	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (tons/yr)
Carbon Monoxide	0.0002	0.0000	0.0002	0.0001	0.0000	0.0001	0.0000	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	0.0036
Carbon Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002
Hydrogen Sulfide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
Methane	0.0106	0.0000	0.0113	0.0052	0.0032	0.0560	0.0000	0.0211	0.0004	0.0000	0.0004	0.0000	0.0000	0.0000	0.0148	0.1231	0.5391
Ethane	0.0316	0.0000	0.0000	0.0156	0.0046	0.0001	0.0220	0.0751	0.0137	0.0000	0.0004	0.0112	0.0957	0.0000	0.0000	0.2700	1.1824
Hydrogen, Water and Nitrogen	0.0592	0.0054	0.0623	0.0257	0.0001	0.0001	0.0000	0.1032	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2562	1.1224
Ammonia	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total VOC	0.0537	0.0000	0.0002	0.0251	0.0145	0.0034	0.0354	0.1125	0.0127	0.0498	0.7771	0.0162	0.0010	0.2191	0.0287	1.3496	5.9112
HAP Summary																	
Butadienes	0.0007	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0140	0.0000	0.0000	0.0000	0.0000	0.0000	0.0147	0.0643
Benzene	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0050	0.0000	0.0000	0.0000	0.0000	0.0000	0.0053	0.0230
Toluene	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0007	0.0000	0.0000	0.0000	0.0000	0.0000	0.0007	0.0030
Xylene/Ethyl Benzene	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0003
Styrene	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0005
Non-Speciated HAP	0.0010	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0198	0.0000	0.0000	0.0000	0.0000	0.0000	0.0208	0.0912
Total HAP	0.0021	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0396	0.0000	0.0000	0.0000	0.0000	0.0000	0.0416	0.1824
Totals (excluding HAP Summary)	0.1554	0.0054	0.0739	0.0717	0.0225	0.0598	0.0575	0.3122	0.0268	0.0498	0.7779	0.0274	0.0967	0.2191	0.0436	1.9998	8.7589

Ethylene Plant Fugitive Emissions Summary
CR C3+ Area Fugitives, CR-16; Column Totals

Constituents	Hydrogen Off-Gas (Comp N)	PSA Off-Gas (Comp U)	De-Butanizer Bottoms (Comp W)	Hydro C3-4 (Comp Z)	Hydro C3-4 Vapor (Comp AA)	Py-Gas Storage Vapor (Comp X)	Quench Water (Comp G)	Propylene Refrigera-tion (Comp AB)	EPN CR-16 Total	
	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (tons/yr)
Carbon Monoxide	0.0007	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0010	0.0042
Carbon Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Methane	0.0454	0.0134	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0589	0.2579
Ethane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0004
Hydrogen, Water and Nitrogen	0.2509	0.0221	0.0000	0.0002	0.0478	0.1185	0.0375	0.0000	0.4771	2.0895
Ammonia	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total VOC	0.0007	0.0002	0.0081	0.0304	0.0661	0.0832	0.0000	0.0280	0.2167	0.9493
Totals	0.2978	0.0359	0.0081	0.0306	0.1140	0.2018	0.0375	0.0280	0.7537	3.3013

Occidental Chemical Corporation
January 2014

CR Hydrogen Vent
EPN CR-19

Basis:

2,880,000 lb/yr hydrogen vent rate (2,000 lb/hr X 24 hr/day X 60 days/yr)
0.1% % methane content of hydrogen
2880.00 lb/yr methane emissions
1.44 tons/yr methane emissions

Engine	Pollutant	Emission Factor (lb/yr)	Emissions (tons/yr)
CR-19 Hydrogen Vent	CH_4	2880	1.44

Calculation methods:

Annual emissions (tons/yr) =Estimated annual vent rate of hydrogen (lb/yr) x methane content of hydrogen (%) x 1 ton/2,000 lb

NOx emissions if vented to high pressure flare - For BACT analysis
50,080 Btu/lb (from "Large Flare - For Modeling.xls)
2,880,000 lb/yr
0.138 lb NOx/MM Btu (from TCEQ permit application)
19,904 lb/yr
9.95 tons/yr

NOx emissions if vented to thermal oxidizers - For BACT analysis
50,080 Btu/lb (from "Large Flare - For Modeling.xls)
2,880,000 lb/yr
0.06 lb NOx/MM Btu
8,654 lb/yr
4.33 tons/yr

CO2 emissions if vented to high pressure flare or thermal oxidizers - For BACT analysis
1.44 tons/yr methane
14 molecular weight methane
44 molecular weight CO2
4.53 tons/yr CO2

Occidental Chemical Corporation
January 2014

Cogeneration Units - Proposed GHG Increased Emissions

EPN's CG-1 and CG-2

(Authorized by Permit Nos. 35335 and PSD-TX-880)

Basis:

215 MM Btu/hr, maximum, total fuel firing rate to provide steam and electrical power for the new NGL facilities
116.91 lb/MM Btu, CO2 factor for natural gas from 40 CFR 98, Subpart C, Table C-1 (converted from 53.02 kg/MM Btu for use with Eq. C-1b)
0.002 lb/MM Btu, CH4 factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.001 kg/MM Btu for use with Eq. C-8b)
0.0002 lb/MM Btu, N2O factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.0001 kg/MM Btu for use with Eq. C-8b)
8,760 hr/yr, hours of operation
Emission calculations below represent maximum emissions for both of the cogeneration units and assume worst-case fuel firing in the heat recover steam generators rather than in the higher efficiency gas turbines

Pollutant	Emission Factor (lb/MM Btu)	Hourly Emissions (lb/hr)	Annual Emissions (tons/yr)
CO_2	116.91	25,135.46	110,093.30
CH_4	0.002	0.47	2.08
N_2O	0.0002	0.05	0.21

Calculation methods:

Hourly emissions (lb/hr) = emission factor (lb/MM Btu) x fuel firing rate (MM Btu/hr)
Annual emissions (tons/yr) = hourly emissions (lb/hr) x hours of operation (hr/yr) x 1 ton/2,000 lb

APPENDIX D
BEST AVAILABLE CONTROL TECHNOLOGY REVIEW

Occidental Chemical Corporation
January 2014

BEST AVAILABLE CONTROL TECHNOLOGY REVIEW

New major stationary sources and major modifications must apply Best Available Control Technology (BACT) for each regulated NSR pollutant subject to PSD review. The review of BACT using the EPA's five-step, top-down BACT approach typically includes the following items for each source category: 1) the identification of available control technologies; 2) the elimination of the technically infeasible alternatives; 3) the ranking of the remaining control technologies; 4) the evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects; and 5) the selection of BACT.

For the sources associated with the proposed Ethylene Plant, the following BACT review will cover the five cracking furnaces, two thermal oxidizers, a high pressure ground flare, an emergency generator engine, a cooling tower, a C3/C4 hydrogenation regenerator vent, fugitive sources identified for four operating areas, and a hydrogen vent.

It should be noted that the existing cogeneration units are not subject to BACT since they are not modified sources. The cogeneration units are included in this application only because they are affected facilities that influence PSD applicability.

EPNs CR-1 through CR-5; Ethane Cracking Furnaces Nos. 1 through 5

Step 1 - The identification of available control technologies. Potential GHG emission control technologies for the cracking furnaces were identified as follows:

a) Low carbon fuels – Use of low carbon fuels such as natural gas or hydrogen based fuels to reduce the amount of GHGs generated in the combustion process.

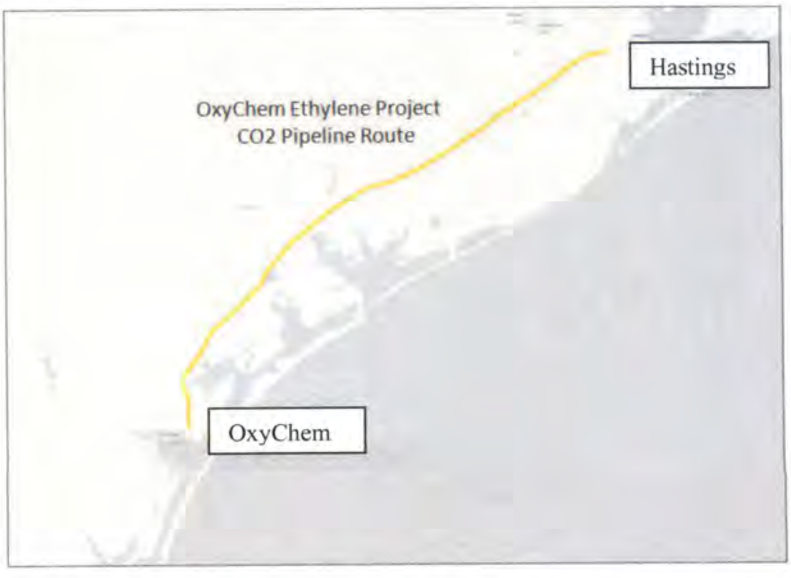
b) Furnace excess air control – Monitoring of oxygen in the flue gas for optimal efficiency.

c) Good operating and maintenance practices – Visual monitoring of flame patterns and periodic cleaning of burner and feed nozzles to assure complete combustion and efficiency. Also includes periodic refractory repair and cleaning of process heating and waste heat recovery systems when required to maximize thermal efficiency.

d) Energy efficient design – Use of waste heat recovery from the furnace flue gas and the furnace process effluent gases, thereby offsetting GHG emissions from other process heating sources. Waste heat recovery would require the installation of heat recovery exchangers on the process outlet gas and the flue gas from the cracking furnaces.

e) Carbon capture and sequestration (CCS) – Capture, compression, transport and geological storage of carbon dioxide from the cracking furnace flue gas exhaust. Carbon dioxide emissions from the cracking furnaces could theoretically be absorbed in a conventional amine solvent. The carbon dioxide could then be concentrated in an amine regenerator vent stream, dried, compressed and routed to oil production facilities using carbon dioxide for enhanced oil recovery (EOR) or stored in geologic formations. The OxyChem Ethylene project evaluated a number of opportunities for carbon dioxide storage or use in EOR. A search of the National Carbon Sequestration Database and Geographic Information System (NATCARB) identified five sites that were evaluated for potential storage or transportation of CO_2: 1) the NRG (Thompsons, TX), 2) University of Texas (~10 miles off-shore, Gulf of Mexico), 3) Hunton (Freeport, TX), 4) the Conoco Phillips project (Sweeny, TX), and 5) the Denbury Hastings CO_2 pipeline near Pearland, TX. The first four sites were not chosen because these sites are currently in the planning or development stages or have been cancelled. Therefore, the nearest currently viable option for sending the captured CO_2 is the Denbury Hastings CO_2 pipeline. Transporting the CO_2 from the Ingleside site to the Hastings field would require a 180 mile pipeline shown on the graphic below.

Mapped Pipeline Route from the proposed OxyChem Ethylene Plant (Ingleside, TX) to Hastings (Pearland, TX)



Step 2 - The elimination of the technically infeasible alternatives. All options identified in Step 1 are considered technically feasible. The use of low carbon fuels, furnace excess air control, good operating and maintenance practices, and waste heat recovery are common to process furnaces in similar industries and have been incorporated into the design of the proposed cracking furnaces for this project. Recovering carbon dioxide in the flue gas from the cracking furnaces is considered technically feasible and will be evaluated in the following steps, however CCS has not been commercially demonstrated for similar ethane cracking processes.

Step 3 - The ranking of the remaining control technologies. The technologies identified in Step 1 that were not eliminated in Step 2 have been ranked based on the ability to reduce GHG emissions from the ethane cracking furnaces.

1. Implementing CCS would reduce GHG emissions from the cracking furnaces by up to 262,612 tons per year (utilizing a hydrogen rich fuel), based on a 90% capture efficiency, and would be the most effective control method for the ethane cracking furnaces.

2. Waste heat recovery can reduce GHG emissions from the furnace by reducing the furnace firing rate and steam demand for the Ethylene Plant. Possible GHG emissions from the furnaces and cogeneration facility can be reduced by approximately 543,270 tons per year due to reduced steam and firing rate demands with the installation of waste heat recovery on the furnaces. Therefore, this is considered the second most effective control technology for the ethylene furnaces.

3. The use of the hydrogen rich vent gas from the ethylene recovery section in lieu of natural gas for fuel in the cracking furnaces reduces the amount of carbon dioxide generated in the cracking furnaces. It is estimated that the carbon dioxide emissions from the cracking furnaces is reduced by about 41% or 412,294 tons per year using this alternative low carbon fuel source. This is considered the third most effective control technology for this application.

4. Excess air control using stack gas oxygen monitors and good operating and maintenance practices are considered good engineering practice and have been included with the proposed furnace design. Implementing these design elements and operational parameter monitoring is effective at minimizing formation of CO_2 in the ethane cracking furnaces, but the effects are not directly quantifiable.

Step 4 - The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects.

The capture, compression and sequestration of the carbon dioxide in the cracking furnace flue gas would reduce the carbon dioxide emissions from the cracking furnaces by up to 262,612 tons per year, based on a 90% capture efficiency, but would require an additional 446 MMBtu/hr of thermal energy to strip the carbon dioxide from the capture solvent. The current steam production of OxyChem facility, including the additional steam produced from waste heat boilers, cannot meet this increased demand without curtailing existing production units as demonstrated in the table below.

Table 1. Ingleside Steam Balance

Steam Generation (Existing Cogeneration)	
Heat Recovery Steam Generator No. 1	1,000 Mlb/hr
Heat Recovery Steam Generator No. 2	1,000 Mlb/hr
Total Production	**2,000 Mlb/hr**
Steam Consumers (Net Consumption)	
Steam Turbine Generator	1,000 Mlb/hr
Existing Process Consumers	750 Mlb/hr
Ethylene Unit (Net Consumption)	120 Mlb/hr
Potential Amine Regenerator for CCS	400 Mlb/hr
Total Consumption including CCS	**2,270 Mlb/hr**
Site Steam Totals	
Site Steam Deficiency	**-270 Mlb/hr**

Therefore, implementation of CCS would require the installation of a new natural gas fired steam boiler that would be a source of additional CO_2 emissions. It is estimated that the increased CO_2 emissions from the new boiler would be 228,158 ton/yr. A summary of the basis for avoided CO_2 emissions is provided in the tables on the following pages.

Table 2: Emissions Assuming Natural Gas Fired Boiler for New Amine Regenerator

Assume maximum firing for maximum CO_2 capture

Max CO_2 emissions from Furnaces (100% load)	13,324	lb/hr per furnace
Number of Furnaces	5	Furnaces
CO_2 Capture (assuming 90% recovery)	262,612	ton/year
Total CO_2 capture	59,957	lb/hr

Use gas processing data on amine absorber-strippers from Campbell Gas Processing Books
From J.M. Campbell & Co Gas Processing Handbook (Table 4.10))

Energy Required per lb of CO_2 for Regeneration	72000	Btu/hr per gpm of DEA
Solvent Specific Gravity	1.1	
Factor per lb Solvent	130.8	Btu/lb of solvent
Solvent Concentration (Aqueous DEA)	25%	
Factor per lb of DEA	523	Btu/lb of DEA
Moles CO_2/Mole DEA	0.2	
Energy Required per lb of CO_2 absorbed	6242.9	Btu/lb CO_2
Additional Steam Energy Required for Amine Regenerator	374.3	MMBtu/hr
Boiler Efficiency	84%	
Fuel Required	445.6	MMBtu/hr
CO_2 Factor	116.9	lb/MMBtu/hr
CO_2 Produced	52,091	lb/hr
CO_2 Produced from boilers for regenerator	228,158	ton/year

Consequently, the net overall reduction in CO_2 emissions from the ethane furnaces from CCS would be 34,454 tons/year (262,612 – 228,158 tons/year). If this additional amount of CO_2 generated was considered in the cost analysis, the total cost would be $1,013/ton. However, the cost effectiveness analysis for a CCS system designed to control the ethane cracking furnaces conservatively did not include the increase in GHG emissions from the new boiler.

The estimated annualized capital and operating and maintenance (O&M) costs for the recovery and compression equipment for the OxyChem ethane cracking furnaces was originally estimated to be $28,536,835 per year (utilizing a capital recovery factor of 6.14% and equipment life of 30 years). However, after a review of similar recently submitted ethylene plant CCS system designs and associated costs that were approved by the EPA Region VI, OxyChem is conservatively adjusting the annualized cost to be $26,530,710 per year. A summary of the costs are included in Table 3.

Table 3 - Economic Analysis for Carbon Capture and Compression

Cost Type	Units	OxyChem's Original Estimate ($ Millions)	Updated Cost Estimate ($ millions)
Carbon Capture Plants - Capital and Operating Expense Estimation			
CO_2 Compressor and Intercoolers	$ (millions)	220.5	27.5
Amine Absorber Systems, CO_2 Purification System, Blower, Piping, Boiler, and Ducting	$ (millions)		213.6
Total Capture and Compression Costs	**$ (millions)**	**220.5**	**241.1**
Utility Plant - Capital and Operating Expense Estimation			
Fuel, Utilities, Amine	$ (millions) / yr	15	11.7
Total Expense Estimation - 90% Capture [1]			
Operating Expense	$ / Ton CO_2 Avoided	$57	$45
Capital Expense [2]	$ / Ton CO_2 Avoided	$52	$56

[1] Calculations –
Operating Expenses / Total CO_2 Captured;
Total Capital Expenses * Capital Recovery Factor / Total CO2 Captured
[2] Based on a capital recovery factor of 6.14% with an expected equipment life of 30 years and an interest rate of 4.5%.

The estimated annualized capital and operating and maintenance (O&M) costs for CO_2 transport was originally estimated to be $29,289,359 per year (utilizing a capital recovery factor of 6.14% and equipment life of 30 years). This included 8 pumping stations that would be required for the 180 mile pipeline. However, utilizing the 2013 National Energy Technology Laboratory, Estimating Carbon Dioxide Transport and Storage Costs 2013 documentation that has been utilized in recently submitted ethylene plant CCS system designs and associated costs that were approved by the EPA Region VI, OxyChem is conservatively adjusting the annualized cost to be about $8,385,233 per year.

According to a recent Environmental Appeals Board petition for another GHG permit, it would be inappropriate to combine CCS implementation costs from two separate sources (i.e. furnaces and thermal oxidizers), as BACT determination is on a source by source basis. Since the ethane cracking furnaces are being evaluated separately from the thermal oxidizers for BACT, all CCS costs have also been evaluated separately. Per the GHG guidance, "EPA has generally recommended that permit applicants and permitting authorities conduct a separate BACT analysis **for each unit**"

A summary of the costs are included in Table 4 and a summary of the carbon compression and pipeline analysis is included in Table 5.

Table 4 - Economic Analysis for CO_2 Transport

Cost Type	OxyChem's Original Estimate [4]	DOE/NETL Calculation[1]		
	Cost ($ millions)	Units	Cost Equation	Cost ($millions)
Pipeline Materials	229.5	$, Diameter (inches), Length (miles)	$70,350 + $2.01 × L × (330.5 × D^2 + 686.7 × D + 26,960)	15.6
Pipeline Labor		$, Diameter (inches), Length (miles)	$371,850 + $2.01 × L × (343.2 × D^2 + 2,074 × D + 170,013)	70.9
Pipeline Miscellaneous [2]		$, Diameter (inches), Length (miles)	$147,250 + $1.55 × L × (8,417 × D + 7,234)	16.3
Pipeline Right of Way		$, Diameter (inches), Length (miles)	$51,200 + $1.28 × L × (577 × D + 29,788)	7.7
Pipeline Control System		$	$111,907	0.1
CO_2 Surge Tank		$	$1,244,724	1.2
Total Materials and Labor Estimation	**229.5**	**$**	--	**111.8**
O&M Expense Estimation (Total for life of equipment)	353.1	$ / mile / year	$8,454	45.7
Total Expense Estimation	582.6	$	-	157.5
Amortized Cost[5]	25.9	$/yr	-	8.4
Total Cost ($/ Ton CO_2)	**$98.5**	**$31.9**		

[1] National Energy Technology Laboratory, Estimating Carbon Dioxide Transport and Storage Costs, United States Department of Energy, Page 12, DOE/NETL-2013/1614.

[2] Per NETL doc: Miscellaneous costs are inclusive of surveying, engineering, supervision, contingencies, allowances for funds used during construction, administration and overheads, and regulatory filing fees
[3] Calculations –
Operating Expenses / Total CO_2 Captured or avoided;
Total Capital Expenses * Capital Recovery Factor / Total CO_2 Captured
[4] OxyChem Original Estimate based on 8 pumping stations for 180 miles of 6 inch diameter pipeline, $0.03/kW for annual pipeline pump electrical requirements and 75% efficiency, and pipeline annual operating expenses of 4% of installed costs.
[5] A capital charge rate of 6.14% was assumed with an expected equipment life of 30 years and an interest rate of 4.5% (per NETL).

Table 5 - Economic Analysis for CCS

Cost Type	Units	Estimated Cost ($ millions)
Carbon Capture Plants - Capital and Operating Expense Estimation		
CO_2 Compressor and Intercoolers	$ (millions)	27.5
Amine Absorber Systems, CO_2 Purification System, Blower, Piping, Boiler, and Ducting	$ (millions)	213.6
Pipeline Material and Costs	$ (millions)	111.8
Utility Plant - Capital and Operating Expense Estimation		
Fuel, Utilities, Amine	$ (millions) / yr	11.7
Piping Annual O&M	$ (millions) / yr	1.52
Total CO_2 CCS Cost Estimation at 90% Capture [1]		
Total	$ / Ton CO_2 Avoided	$132.96

[1] A capital charge rate of 6.14% was assumed with an expected equipment life of 30 years and an interest rate of 4.5% (per NETL).

An estimated annual revenue from CCS would be $5,250,000 based on $20 per ton for use in enhanced oil recovery. Based on the amount of CO_2 that could be captured, OxyChem would not qualify for the additional tax credit. The average cost effectiveness for CCS is estimated to be $113/ton of CO_2 emission reduction based on annualized cost estimates, as shown in Table 6 below.

Table 6 - CCS Cost Effectiveness including Offsets (Sale of CO_2)

CCS Technology for CO_2 Emissions	Tons of CO2 Avoided per Year[1]	Cost - 90% Capture ($/ton of CO_2 Avoided)	Total Annual Cost[2] (Million $ per year)
Capture and Compression	262,612	$101	$26.53
Transport	262,612	$31.93	$8.39
Total CCS Cost (without offsets)	**262,612**	**$132.96**	**$34.92**
Sale to EOR	262,612	($20.00)	($5.25)
Total CCS Cost (with offsets)	**262,612**	**$112.96**	**$29.66**

[1] This represents 90% Capture of the total CO_2 emissions from the ethane cracking furnaces.
[2] Total Annual Cost represents an amortized cost for the capital expenditure and operating and maintenance costs. A capital recovery rate of 6% was assumed with an expected equipment life of 30 years and interest rate of 4.5%.

These costs are comparable to similar facilities which have been permitted recently and considered to be cost prohibitive by EPA. Therefore, this option is rejected as a control option for GHG emissions.

Waste Heat Recovery - The ethane cracking furnace design includes energy efficiencies such as the use of heat exchangers on the process and flue gas outlet of the cracking furnaces to recover waste heat. The waste heat recovery will recover 119.87 MMBtu/hr per furnace that can be utilized by the Ethylene Plant. This will reduce the amount of steam required by the cogeneration and thereby avoid 350,343 tons per year CO_2 emissions from the combustion of natural gas to generate steam (assuming 84% boiler efficiency and 116.91 lbs CO_2/MMBtu). In addition, the waste heat recovery will be used to preheat the ethane feed mix at an average of 64.44 MMBtu/hr per furnace. This will also reduce the amount of steam required by the cogeneration unit and thereby avoid an additional 192,927 tons per year of CO_2 emissions from the burning of natural gas to generate steam (assuming 84% boiler efficiency and 116.91 lbs CO_2/MMBtu). Therefore, the total CO_2 avoided due to the waste heat recovery is estimated at 543,270 tons per year CO_2 or 0.72 lbs CO_2/lb of Ethylene.

The use of the hydrogen rich vent gas for furnace fuel is considered part of the furnace operation for reducing CO_2 formation. Similarly, energy efficient design, good operating and maintenance practices, and stack gas oxygen monitors for controlling furnace excess air are considered good engineering practice and have been included with the proposed design.

Step 5 - The selection of BACT. BACT for the ethane cracking furnaces will include the following:

a) Low carbon fuels – Use of low carbon fuels such as the proposed hydrogen rich vent gas from the ethylene recovery section, instead of only natural gas for fuel in the cracking furnaces, will reduce the amount of carbon dioxide generated in the combustion process.

b) Energy efficient design – Use of waste heat recovery from the furnace flue gas in the form of heat exchangers on the furnace process outlets; and boiler feed water economizers in the furnace stacks, offsets GHG emissions from other process heating sources. The stack gas temperatures will be maintained at less than 340°F during normal operation, which is consistent with other recently issued permits for similar processes.

c) Furnace excess air control – Monitoring of oxygen in the stack gas and controlling excess air based on a limit of 10% oxygen is for optimal efficiency.

d) Good operating and maintenance practices – Visual monitoring of flame patterns and periodic cleaning of burner and feed nozzles to assure complete combustion and efficiency. Also includes periodic refractory repair and cleaning of process heating and waste heat recovery systems when required to maximize thermal efficiency.

The following table on the next page lists the proposed compliance monitoring methodology selected as BACT for the ethane cracking furnaces:

Table 7: Furnace Operating and Maintenance Practices

Furnace Operating and Maintenance Practices					
Operating/ Maintenance Practice	**Frequency**	**Method of Ensuring Compliance**	**Recordkeeping Method**	**Indicators**	**Corrective Actions**
Stack oxygen concentration monitoring	Continuous	Maintain records, planned maintenance and calibrations	Electronic	Oxygen concentration >10%	Operating parameter adjustment
Stack temperature monitoring	Continuous	Maintain records, planned maintenance, and calibrations	Electronic	Stack temperature > 340 °F	Operating parameter adjustment
Visual inspection of burners during operation	Weekly	Established operator work requirement	Electronic and paper	Abnormal flame pattern	Online cleaning or repair
Visual inspection of burners during furnace shutdown	2 to 3 times per year	Planned maintenance schedule	Maintenance records	Damaged burner or refractory	Repair or replace equipment
TLE Performance	Continuous	Maintain records	Electronic	High process fluid exit temperature (>850°F)	TLE cleaning

EPNs CR-1-MSS through CR-5-MSS; Ethane Cracking Furnaces Nos. 1 through 5 - MSS Activities

Carbon deposits or coke gradually build up on the tube walls of the furnaces during normal operations. This coke build up interferes with heat transfer through the tubes, which increases furnace temperatures and reduces thermal efficiency. The furnace deposits must periodically be removed or decoked. This decoking is accomplished with the introduction of steam and air at high temperatures to convert the deposits to gaseous carbon dioxide. The exhaust gas is discharged through the furnace with the flue gas. The carbon dioxide emissions from this decoking maintenance activity are included in the emissions from the cracking furnaces. This section will address BACT for carbon dioxide that is generated by removing the coke deposits.

Step 1 - The identification of available control technologies. Potential GHG emission control technologies for decoking the cracking furnaces were identified as the follows:

a) Mechanical cleaning – Use shot blast or hydro-lancing to mechanically remove coke from the tubes. The coke would then be disposed of in a solid waste landfill.

b) Reduced air – Limit the air feed to reduce carbon dioxide formation.

c) Low coking design and operation – Proper furnace coil design and using anti-coking agents during normal operation will tend to reduce coke formation and minimize carbon dioxide formation.

d) Good operating practices – Periodic visual inspections of the furnace and monitoring of the furnace stack temperature to determine when decoking is needed.

Step 2 - The elimination of the technically infeasible alternatives. The reduction in air is not technically feasible. Limiting air could result in an incomplete decoke, which would lead to an increase in the frequency of decoke events. Because coke buildup acts as an insulator, its presence decreases the efficiency of the furnace, resulting in an increase in CO_2. Therefore, reduced air feed is eliminated as control technology. All other options are considered technically feasible.

Step 3 - The ranking of the remaining control technologies. The technologies identified in Step 1 that were not eliminated in Step 2 have been ranked based on the ability to reduce GHG emissions from the ethane cracking furnaces.

1. Physical removal of the coke would provide the most effective control of carbon dioxide emissions. It is estimated that up to 100% or 310 tons/yr of carbon dioxide production could be eliminated by mechanical cleaning and would be the most effective control method for the ethane cracking furnaces.

2. GHG reductions from coil design and use of anti-coking agents is difficult to quantify. However, it is estimated that these activities will extend the furnace run life by 25% and increase furnace run time between decoking activities, resulting in a reduction in carbon dioxide emissions equivalent to about 160 tons per year. This is considered the second most effective control technology for this application.

3. Visual inspections and furnace stack temperature monitoring have been included with the proposed furnace design. Implementing these elements is effective in avoiding unnecessary CO_2 in the ethane cracking furnaces, but the effects are not directly quantifiable.

Step 4 - The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects.

Mechanical Cleaning - The cracking furnaces have vertical tube coils of varying diameters. Mechanical cleaning of the coils would require the cutting and physical removal of the furnace coils and bends during each decoke. The coils would then have to be re-welded after cleaning. The costs and potential safety issues with the re-welding of materials are excessive for the minimal reduction in GHG emissions. The operation would also generate additional PM emissions from the decoking, which is a highly regulated pollutant. Mechanical cleaning is rejected as a control option for GHG emissions from decoking.

Low coking design and operation - Minimizing coke formation through the proper furnace coil design for the feedstock and the use of anti-coking agents will increase furnace run time between decoking and improve furnace efficiency, thereby reducing operating costs. These design features are included in the proposed furnace design.

Good operating practices - Visual inspections and furnace stack temperature monitoring have been included with the proposed furnace design.

Step 5 - The selection of BACT. The use of a proper coil design for the ethane cracking furnaces and using anti-coking agents as needed in the furnace feed to maximize the furnace run time between decokes is considered BACT for minimizing coke formation. The amount of anti-coking agent will be highly dependent on the furnace condition and operation, therefore, a frequency or amount of anti-coking agent addition cannot be quantified.

Good operating practices are also selected as BACT for minimizing coke formation include periodic visual inspections of the furnace firebox and cleaning the convection section when the furnace stack temperatures exceed 340°F. The total number of furnace decokes is expected to be 36 per year. This frequency was the basis for estimating GHG emissions, however, the actual number of decoke events required per year can vary and the need for decoking will be based on temperature monitoring, as described above.

EPNs CR-6 and CR-7; CR Thermal Oxidizer Nos. 1 and 2

Non-condensable vent streams from the ethane cracking process, storage and loading area are generally combusted to destroy VOC before the inert gases are released to the atmosphere. This control can be accomplished in elevated flares, enclosed flares and vapor combustors (thermal oxidizers). The destruction efficiency and the potential GHG control technologies vary depending on the type of VOC control device selected.

Thermal oxidizers were selected as the primary control technology because they can achieve a higher destruction efficiency of VOCs than flares, and provide for heat recovery. Waste heat recovery on the two thermal oxidizers included in the proposed design is an energy efficiency improvement by using waste heat to generate steam; and thereby lessening fuel firing in other steam generating sources. Therefore, use of a thermal oxidizer with waste heat recovery for control of low pressure vents is considered BACT relative to the use of a flare.

Step 1 - The identification of available control technologies. The following BACT analysis was used to identify the best method for controlling GHG emissions from the selected thermal oxidizers are identified as follows.

a) Thermal Efficient Combustor design – Design achieves good fuel and air mixing with sufficient temperatures to ensure complete combustion and to maximize thermal efficiency.

b) Low carbon fuels – Use of low carbon fuels to reduce the amount of carbon dioxide generated by burner or supplemental fuel combustion process.

c) Oxidizer air/fuel control – Monitoring of oxygen in the flue gas and firebox temperature for optimal efficiency.

c) Flame monitoring and periodic tune-up – Visual monitoring of flame patterns and cleaning of burner and feed nozzles to assure complete combustion and efficiency. Also, includes periodic refractory repair and cleaning of waste heat recovery systems when required to maximize thermal efficiency.

d) Waste heat recovery – Use of thermal oxidizers with high firebox temperatures and waste heat recovery from the oxidizer exhaust to preheat the combustion air or produce steam for use at the site, thereby offsetting GHG emissions from other fuel combustion sources.

e) Combustion CO_2 capture and storage – Capture, compression, transport and geological storage or use of CO_2 in the thermal oxidizer flue gas exhaust. CO_2 emissions from the thermal oxidizer flue gas could theoretically be absorbed in a conventional amine solvent. The CO_2 could then be concentrated in an amine regenerator vent stream, compressed and routed to oil production facilities using CO_2 for EOR or stored in geologic formations. OxyChem previously noted that the measured route to EOR (180 miles) is closer than other potential geologic storage sites. The nearest location for EOR would be the Hastings CO_2 flood near Pearland, Texas.

Step 2 - The elimination of the technically infeasible alternatives. All options identified above are considered technically feasible. Carbon capture and sequestration (CCS) of the post-controlled vent gas from the thermal oxidizers is considered technically feasible, but not demonstrated commercially on a similar, VOC control device system.

Step 3 - The ranking of the remaining control technologies. The technologies identified in Step 1 that were not eliminated in Step 2 have been ranked based on the ability to reduce GHG emissions from the thermal oxidizer.

1. Implementing carbon capture and compression would reduce GHG emissions from the thermal oxidizers by 97,090 tons/yr based on 90% capture of carbon dioxide and would be the most effective control method for the thermal oxidizers.

2. Waste heat recovery can reduce GHG emissions from the cogeneration units by reducing steam demand for the proposed Ethylene Plant. It is estimated that GHG emissions from the cogeneration facilities will be reduced by about 18,200 tons/yr as a result of installing waste heat recovery on thermal oxidizers. This reduction is based on the more efficient cogeneration operation of raising gas turbine loads to maintain power output. This approach is considered the next most effective control technology.

3. Combustor design, oxidizer air/fuel with temperature control, stack gas oxygen monitors, use of pipeline natural gas for burner and supplemental fuel, and flame monitoring are considered good engineering practice and have been included with the proposed design. Evaluating their effectiveness and a subsequent evaluation of each technology is difficult to quantify, but they are all considered effective for minimizing GHG emissions from the thermal oxidizers.

Step 4 - The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects.

The capture, compression and sequestration of the CO_2 in the flue gas from the thermal oxidizers would reduce the GHG emissions from the thermal oxidizers by 97,090 tons/yr based on 90% capture efficiency, but would require an additional 165 MMBtu/hr of fuel to strip the CO_2 from the solvent. A new natural gas fired boiler would be needed to supply this additional steam demand and was included in the cost analysis for CCS. This approach would also create additional GHG emissions. It is estimated that the increased GHG emissions from the new boiler for CCS would be 84,353 tons/yr.

Table 8 - Emissions Assuming Natural Gas Fired Boiler for new Amine Regenerator

Assume maximum firing for maximum CO_2 capture		
Max CO_2 emissions from Thermal Oxidizers (100% load)	12,315	lb/hr per thermal oxidizer
CO_2 Capture (assuming 90% recovery) - 2 Thermal Oxidizers	97,090	ton/year
Total CO_2 capture	22,167	lb/hr
Use gas processing data on amine absorber-strippers from Campbell Gas Processing Books		
From J.M. Campbell & Co Gas Processing Handbook (Table 4.10))		
Energy Required per lb of CO_2 for Regeneration	72000	Btu/hr per gpm of DEA
Solvent Specific Gravity	1.1	
Factor per lb Solvent	130.8	Btu/lb of solvent
Solvent Concentration (Aqueous DEA)	25%	
Factor per lb of DEA	523	Btu/lb of DEA
Moles CO_2/Mole DEA	0.2	
Energy Required per lb of CO_2 absorbed	6242.9	Btu/lb CO2
Additional Steam Energy Required for Amine Regenerator	138.4	MMBtu/hr
Boiler Efficiency	84%	
Fuel Required	164.7	MMBtu/hr
CO_2 Factor	116.9	lb/MMBtu/hr
CO_2 Produced	19,259	lb/hr
CO_2 Produced from boilers for regenerator	84,353	ton/year

Consequently, the net overall reduction in CO_2 emissions from the thermal oxidizers from CCS would be 12,737 tons/year. (97,090 – 84,353 tons/year). If this additional amount of CO_2 generated was considered in the cost analysis, the total cost would be $1,428/ton. However, the cost effectiveness analysis for a CCS system designed to control the thermal oxidizers conservatively does not include the increase in GHG emissions from the new boiler.

The estimated annualized capital and operating and maintenance (O&M) costs for the recovery and compression equipment for the OxyChem thermal oxidizers was originally estimated to be $12,397,681 per year (utilizing a capital recovery factor of 6.14% and equipment life of 30 years). However, after a review of similar recently submitted ethylene plant CCS system designs and associated costs that were approved by the EPA Region VI, OxyChem is conservatively adjusting the annualized cost to be about $9,808,791 per year. A summary of the costs are included in Table 9.

Table 9 - Economic Analysis for Carbon Capture and Compression

Cost Type	Units	OxyChem's Original Estimate ($ Millions)	Updated Cost Estimate ($ millions)
Carbon Capture Plants - Capital and Operating Expense Estimation			
CO_2 Compressor and Intercoolers	$ (millions)	120.5	10.2
Amine Absorber Systems, CO_2 Purification System, Blower, Piping, Boiler, and Ducting	$ (millions)		79.0
Total Capture and Compression Costs	**$ (millions)**	**120.5**	**89.1**
Utility Plant - Capital and Operating Expense Estimation			
Fuel, Utilities, Amine	$ (millions) / yr	15	4.3
Total Expense Estimation - 90% Capture [1]			
Operating Expense	$ / Ton CO_2 Avoided	$51	$45
Capital Expense [2]	$ / Ton CO_2 Avoided	$76	$56

[1] Calculations –
Operating Expenses / Total CO_2 Captured;
Total Capital Expenses * Capital Recovery Factor / Total CO2 Captured
[2] Based on a capital recovery factor of 6.14% with an expected equipment life of 30 years and an interest rate of 4.5%.

The estimated annualized capital and operating and maintenance (O&M) costs for CO_2 transport was originally estimated to be $29,289,359 per year (utilizing a capital recovery factor of 6.14% and equipment life of 30 years). This included 8 pumping stations that would be required for the 180 mile pipeline. However, utilizing the 2013 National Energy Technology Laboratory, Estimating Carbon Dioxide Transport and Storage Costs 2013 documentation that has been utilized in recently submitted ethylene plant CCS system designs and associated costs that were approved by the EPA Region VI, OxyChem is conservatively adjusting the annualized cost to be about $8,385,233 per year. Additionally, significant potential corrosion issues and material selection requirements would be created by the sulfur dioxide in the flue gas.

According to a recent Environmental Appeals Board petition for another GHG permit, it would be inappropriate to combine CCS implementation costs from two separate sources (i.e. furnaces and thermal oxidizers), as BACT determination is on a source by source basis. Since the thermal oxidizers are being evaluated separately from the ethane cracking furnaces for BACT, all CCS costs have also been evaluated separately. Per the GHG guidance, "EPA has generally recommended that permit applicants and permitting authorities conduct a separate BACT analysis **for each unit**"

A summary of the costs are included in Table 4 in a previous section and a summary of the carbon compression and pipeline analysis is included in Table 10.

Table 10 - Economic Analysis for CCS

Cost Type	Units	Estimated Cost ($ millions)
Carbon Capture Plants - Capital and Operating Expense Estimation		
CO_2 Compressor and Intercoolers	$ (millions)	10.2
Amine Absorber Systems, CO_2 Purification System, Blower, Piping, Boiler, and Ducting	$ (millions)	79.0
Pipeline Material and Costs	$ (millions)	111.8
Utility Plant - Capital and Operating Expense Estimation		
Fuel, Utilities, Amine	$ (millions) / yr	4.3
Piping Annual O&M	$ (millions) / yr	1.52
Total CO_2 CCS Cost Estimation at 90% Capture [1]		
Total	$ / Ton CO_2 Avoided	$187.39

[1] A capital charge rate of 6.14% was assumed with an expected equipment life of 30 years and an interest rate of 4.5% (per NETL).

An estimated annual revenue from the sale of CO_2 would be $1,940,000 based on $20 per ton for use in EOR. Based on the amount of CO_2 that could be captured, OxyChem would not qualify for the additional tax credit. The average cost effectiveness for CCS is estimated to be $167/ton of CO_2 emission reduction based on annualized cost estimates, as shown in Table 11 below.

Table 11 - CCS Cost Effectiveness including Offsets (Sale of CO_2)

CCS Technology for CO_2 Emissions	Tons of CO2 Avoided per Year[1]	Cost - 90% Capture ($/ton of CO_2 Avoided)	Total Annual Cost[2] (Million $ per year)
Capture and Compression	97,091	$101	$9.81
Transport	97,091	$86.36	$8.39
Total CCS Cost (without offsets)	**97,091**	**$187.39**	**$18.19**
Sale to EOR	97,091	($20.00)	($1.94)
Total CCS Cost (with offsets)	**97,091**	**$167.39**	**$16.25**

[1] This represents 90% Capture of the total CO_2 emissions from the thermal oxidizers.
[2] Total Annual Cost represents an amortized cost for the capital expenditure and operating and maintenance costs. A capital charge rate of 6.14% was assumed with an expected equipment life of 30 years and interest rate of 4.5%.

These costs compare to similar facilities which have been permitted recently and considered to be cost prohibitive by EPA. Therefore, this option is rejected as a control option for GHG emissions.

Combustor design, oxidizer air/fuel with temperature control, stack gas oxygen monitors and flame monitoring are considered good engineering practice and have been included with the proposed design. Evaluating their effectiveness and a subsequent evaluation of each technology was not considered necessary for this BACT determination.

Step 5 - The selection of BACT. Implementing the following design and operating practices is considered BACT for minimizing GHG emissions from the proposed thermal oxidizers in this project:

a) Waste heat recovery – The thermal oxidizers will operate with high firebox temperatures and waste heat recovery from the oxidizer exhaust to preheat the combustion air and produce steam for use at the site. Heat recovery will be ensured by monitoring waste heat with a target stack temperature of approximately 550 °F. As a result, GHG emissions will be minimized from other fuel combustion sources.

b) Thermal Efficient Combustor design – Thermal efficient design achieves good fuel and air mixing with sufficient temperatures to ensure complete combustion and to maximize thermal efficiency. The firebox will be lined with refractory to minimize heat losses to the atmosphere. The firebox temperature will be monitored and maintained at a temperature of 1,300 °F or more to assure complete combustion and improve energy recovery.

c) Use of pipeline natural gas for burner and supplemental fuel will minimize GHG emissions and therefore is considered part of good operation practices.

d) Oxidizer air/fuel control – Monitoring of oxygen in the flue gas and firebox temperature for optimal efficiency will minimize GHG emissions from the thermal oxidizers. An oxygen analyzer in each stack will be provided to assure the proper amount of air is used in the combustion process. Vent gas feed, supplemental natural gas fuel and combustion air flow will be metered into each thermal oxidizer.

e) Flame monitoring and periodic tune-up – Visual monitoring of flame patterns and cleaning of burner and feed nozzles when needed to assure complete combustion and efficiency. Periodic refractory repair and cleaning of waste heat recovery systems when required will maximize thermal efficiency.

Table 12: Thermal Oxidizer Operating and Maintenance Practices

Furnace Operating and Maintenance Practices					
Operating/ Maintenance Practice	**Frequency**	**Method of Ensuring Compliance**	**Recordkeeping Method**	**Indicators**	**Corrective Actions**
Stack oxygen concentration monitoring	Continuous	Maintain records, planned maintenance and calibrations	Electronic	Oxygen concentration >10% averaged daily	Operating parameter adjustment
Thermal Oxidizer firebox temperature monitoring	Continuous	Maintain records, planned maintenance, and calibrations	Electronic	Firebox temperature > 1300 °F on an hourly basis	Operating parameter adjustment
Waste Heat Recovery exhaust temperature monitoring	Continuous	Maintain records, planned maintenance, and calibrations	Electronic	Stack temperature < 550 °F on an hourly basis	Operating parameter adjustment
Thermal Oxidizer Feed Flow monitoring on natural gas, waste gas and combustion air flows.	Continuous	Maintain records, planned maintenance, and calibrations	Electronic	-	-

EPN CR-8; CR High Pressure Flare

The high pressure flare is used to safely combust of large volumes of non-condensable flammable hydrocarbon vapor streams during start-up and shutdown, emergency conditions and decommissioning of large volumes of hydrocarbons for maintenance. Under normal operation, the only GHG emissions associated with the flare are from the natural gas pilot burners. This BACT analysis considers potential control technologies for combusting natural gas in the flare pilots.

Step 1 - The identification of available control technologies. The only viable control technologies for reducing GHG emissions from the flare are minimizing the size and number of the pilots. Potential GHG emission control technologies for the emergency flare are identified as follows:

a) Low carbon fuels – Use of low carbon fuels to reduce the amount of carbon dioxide generated in the pilot fuel combustion process.

b) Pilot reliability and sizing – The use of energy efficient (low BTU) pilots to minimize natural gas consumption.

c) Pilot flame monitoring – Monitoring of the pilots with temperature monitors.

Step 2 - The elimination of the technically infeasible alternatives. All options identified above are considered technically feasible.

Step 3 - The ranking of the remaining control technologies. The technologies identified in Step 1 that were not eliminated in Step 2 have been ranked based on the ability to reduce GHG emissions from the high pressure flare.

1. Modern high efficiency pilots can reduce natural gas consumption by about 30% over larger traditional pilots. This approach will reduce GHG emissions by about 253 tons/yr. This option is considered the most effective technology.

2. Use of pipeline natural gas for pilot fuel will assure reliable flare operation while minimizing GHG emission compared to other carbon rich fuels. This option is considered the second most effective control technology.

3. Pilot flame monitoring is considered good operational practices which have been included with the proposed design.

Step 4 - The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects. High efficiency pilots reduce natural gas consumption as well as GHG emissions and do not cost more than larger traditional pilots. Therefore, they are included in the proposed design. Use of pipeline natural gas for pilot fuel, pilot flame monitoring, and burner preventative maintenance are considered good operational practices for safety as well as environmental compliance and has been included with the proposed design.

Step 5 - The selection of BACT. The use of high efficiency pilots with good operational practices including use of pipeline natural gas for pilot fuel and pilot flame monitoring will be included for safety and performance. Total pilot duty for all stages will be minimized, and therefore GHG emissions will be minimized.

Each pilot will be monitored with a thermocouple. Both electronic and flame front generator systems will be provided for lighting the pilots.

EPN CR-8-MSS; CR High Pressure Flare - MSS Activities

As mentioned above, the high pressure flare is used to safely combust of large volumes of non-condensable flammable hydrocarbon vapor streams during start-up and shutdown, emergency conditions and decommissioning of equipment for maintenance.

Step 1 - The identification of available control technologies. This BACT analysis considers potential GHG emission control technologies for planned MSS activities controlled by the high pressure flare that are identified as follows:

a) Staged flare design – the installation of a staged flare design with good combustion practices to minimize assist gas during low load operation will reduce GHG emissions from the flare when in operation.

b) Low carbon assist gas – The use of a low carbon fuel for assist gas will reduce GHG emissions from the flare when assist gas is required at low planned MSS loads.

c) Waste heat recovery – Use of waste heat recovery from the planned MSS flare exhaust to produce steam for use at the site, thereby offsetting GHG emissions from other fuel combustion sources.

d) Combustion CO_2 capture and storage – Capture, compression, transport and geological storage or use of CO_2 in the planned MSS flare exhaust.

Step 2 - The elimination of the technically infeasible alternatives. Waste heat recovery and CO_2 capture and storage would require an enclosed combustion system. This is not technically feasible for safety reasons since the flare also controls instantaneous high flows from the emergency relief system. Staged flare design and low carbon assist gases are technically feasible.

Step 3 - The ranking of the remaining control technologies. The technologies identified in Step 1 that were not eliminated in Step 2 have been ranked based on the ability to reduce GHG emissions from the high pressure flare.

1. A staged flare design minimizes the use of supplemental assist gas required for complete combustion over a large operating range of planned MSS for the flare. This is considered the most effective control technology.

2. The use of a low carbon assist gas such as natural gas will further reduce the GHG emissions when assist gas is required at very low planned MSS loads. This approach is considered the next most effective technology for GHG emission control for this application.

Step 4 - The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects. Both control options are considered cost-effective with minimal energy and environmental effects. Therefore, both technologies will be utilized in the design and operation of the high pressure flare.

Step 5 - The selection of BACT. The use of a staged flare with good combustion practices provides the most reliable and effective control of VOC emissions with the least amount of supplemental assist fuel, which also minimizes cost and GHG emissions. Natural gas is also considered the most reliable and economical assist gas. Both of these options are considered BACT for this source.

EPN CR-9; CR Emergency Generator Diesel Engine

The diesel-fired emergency generator engine is included in this application for the Ethylene Plant because the engine generates GHG emissions during its scheduled testing. Use of this engine for emergency conditions will not be authorized by this permit since these emergency events are not subject to permitting requirements.

Step 1 - The identification of available control technologies. A natural gas-fired or electrically driven engine could be considered as alternatives to a diesel engine; however, its availability of natural gas and/or electricity during emergency events is not as certain as a diesel-fuel, and so, these alternatives are not considered as practical technologies for this service.

Potential GHG emission control technologies considered in the BACT analysis for this engine are identified as follows:

a) EPA Tier 2 (40 CFR 89.112 Table 1) level of emission limitations for combustion products.

b) Change oil and filter every 500 hours of operation or annually, whichever comes first.

c) Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first.

d) Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

Step 2 - The elimination of the technically infeasible alternatives. All options identified above are considered technically feasible.

Step 3 - The ranking of the remaining control technologies. The ranking of the identified control technologies for emergency diesel engines mentioned in Step 1are difficult to determine relative to effectiveness of emissions control, but all are expected to be relevant for maintaining clean operations. These are based on the 40 CFR Part 63, Subpart ZZZZ (RICE MACT) requirements, and therefore are meant to minimize emissions.

Step 4 - The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects. All of the available control technologies identified are considered cost-effective and have minimal negative energy and environmental impacts.

Step 5 - The selection of BACT. All of the identified control technologies in Step 1 are considered as appropriate measures of BACT and will be utilized for minimizing GHG emissions from the diesel emergency generator engine.

EPN CR-11; CR Cooling Tower

The cooling requirements for the proposed Ethylene Plant will be provided by evaporative cooling systems. To prevent scale formation, acid is injected into the circulation water system to reduce the alkalinity and pH. In the process, bicarbonate ion is converted into CO_2 which de-gasses in the cooling tower. CO_2 is discharged to the atmosphere through the mechanical draft cooling tower fan stacks.

Step 1 - The identification of available control technologies. Potential GHG emission control technologies for the cooling tower are identified as follows:

a) Low cycles of concentration – The tower could be operated at sufficiently low cycles of concentration so as to not require any acid addition.

b) Acid and blowdown control – Monitoring of circulating water pH and conductivity to control the acid addition and blowdown to control water chemistry.

c) Pretreatment of make-up water – Use a reverse osmosis system to remove bicarbonates in the make-up water.

d) Once-through seawater cooling – Use of once through seawater for process cooling rather than an evaporative cooling system.

e) Air cooling – Use of air coolers rather than an evaporative cooling water system for process cooling.

Step 2 - The elimination of the technically infeasible alternatives. All options identified above are considered technically feasible.

Step 3 - The ranking of the remaining control technologies. The technologies identified in Step 1 that were not eliminated in Step 2 have been ranked based on the ability to reduce GHG emissions from the cooling tower.

1. The use of once through seawater cooling tower would eliminate 100% of CO_2 emission from the cooling tower with minimal increase in power or thermal combustion related GHG emissions. This approach is considered the most effective control for GHG emissions.

2. The use of air cooling would also eliminate 100% of the CO_2 emissions from the cooling tower; however it would significantly increase the power and thermal energy requirements for the Ethylene plant due to higher operating temperatures and pressures in the refrigeration and distillation column condensers. This approach is considered the second highest effective control technology for cooling towers. However, this technology would result in increased GHG emissions from the cogeneration facilities.

3. Pretreatment of the make-up water in a reverse osmosis system could remove most of the bicarbonates from the cooling tower make-up and potentially eliminate the CO_2 emissions from the cooling tower. This approach is considered the third most effective control technology for the cooling towers. However, this pretreatment would result in increased GHG emissions from the cogeneration facilities for the additional power requirements for the reverse osmosis systems, which require high water pressure to operate effectively.

4. Operation of the cooling tower with an increased wastewater blowdown rate to eliminate the needed acid addition and thereby bicarbonate concentration (aka low cycles of concentration), could reduce the CO_2 emissions by 80-90%. There is still some dissolved CO_2 in the make-up water that would be stripped out even if no acid were added. This approach is considered the next most effective control technology.

5. The effect on GHG emissions of using pH and specific conductivity monitoring to control the acid injection and blowdown is difficult to assess, but it is considered potentially effective means of reducing GHG emissions.

Step 4 - The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects.

Once through seawater cooling – The use of once through seawater cooling might be considered detrimental to fish and wildlife. The use of sea water can also lead to increased fouling of heat exchangers. Therefore, due to minimal reduction in GHG emissions, this technology is not selected as a control option for GHG emission on the basis of these negative consequences.

Air Cooling - The use of air cooling would eliminate the cooling tower GHG emissions, but would increase the emissions from the cogeneration facilities. It is difficult to assess quantities, but air cooling for these facilities would generally be expected to increase energy consumption by 5 - 10 %. This approach would generate 8,000 to 16,000 tons per year of increased GHG emissions from the cogeneration facilities. The increased emission would certainly be significantly more than the 668 tons per year that would be eliminated from the cooling tower. Therefore, air cooling is rejected on the basis of overall energy consumption and the resulting increase in GHG emissions.

Pretreatment of water makeup - Pretreatment of the make-up water in a reverse osmosis system would require increasing the water pressure by several hundred psig. The additional power requirements would add about 4 MMBtu/hr of natural gas firing at the cogeneration facilities, increasing the GHG emissions by 2,048 tons per year. These GHG emissions more than off-sets the elimination of the 668 tons per year of GHG emissions from the cooling tower. Therefore, pretreatment of the make-up water by reverse osmosis is rejected due to the overall potential increase in GHG emissions.

Low Cycles of Concentration- The blowdown rate from the cooling tower would need to be increased from 300 gallons per minute to at least 800 - 1200 gallons per minute to prevent scaling in the cooling water system without any acid addition. There is no other use for this water and it would have to be discharged as wastewater. This approach is considered extremely wasteful of fresh water, especially considering the minimal reduction in GHG emissions that would be realized, and therefore, this approach is rejected as a reasonable control option.

Acid and Blowdown Control - The use of pH and specific conductance monitoring of the cooling tower water have been used in industry to control scaling and/or corrosion in the cooling tower system. Implementation of the pH and conductivity monitors can also provided some control of GHG emissions by maintaining consistent alkalinity in the cooling tower water. These monitors are considered cost-effective with minimal energy and environmental impacts.

Step 5 - The selection of BACT. OxyChem considers the following as BACT for the proposed cooling tower: install pH and conductivity analyzers on the cooling water supply to control acid addition and blowdown.

Laboratory instruments will be used to periodically check the accuracy of these devices and provide information when the on-line analyzers are out of service for an extended period of time due to maintenance. This approach will minimize the GHG emissions associated with the cooling tower and are considered BACT.

EPN CR-12; C3/C4 Hydrogenation Reactor Regeneration Vent – MSS Activities

The unsaturated C3's and C4's are hydrogenated to propane and butane over a fixed bed catalyst in the C3/C4 Hydrogenation Reactor. Over time, carbon will deposit over the catalyst surface. Periodically the carbon deposits must be removed to maintain catalyst activity and reactor conversion. This is accomplished with the introduction of high temperature steam and air to convert the carbon deposits to gaseous carbon dioxide. The exhaust gas is discharged to the atmosphere during this operation. Eventually the catalyst can no longer be successfully regenerated and must be replaced.

Step 1 - The identification of available control technologies. Potential GHG emission control technologies for the C3/C4 Hydrogenation Reactor Regeneration Vent were identified as the follows:

a) Catalyst disposal – Dispose of catalyst and replace with new catalyst instead of regenerating the catalyst.

b) Reduced air – Limit the air feed to reduce carbon dioxide formation.

c) Low coking design and operation – Proper reactor design and operation will tend to reduce coke formation and minimize carbon dioxide formation.

Step 2 - The elimination of the technically infeasible alternatives. All of the identified alternatives are technically feasible.

Step 3 - The ranking of the remaining control technologies. The technologies identified in Step 1 that were not eliminated in Step 2 have been ranked based on the ability to reduce GHG emissions from the C3/C4 Hydrogenation Reactor Regeneration Vent.

1. Disposing of the catalyst by landfill would eliminate 100% of the GHG emissions (13 tons per year) from this source. This is the most effective control technology for GHG emissions from this source.

2. Reducing the air would result in some of the carbon being converted to carbon monoxide instead of carbon dioxide. It is estimated that potentially as much as 50% of the carbon could be converted to carbon monoxide instead of carbon dioxide which would reduce carbon dioxide emissions by 6.5 tons per year. This is considered the second most effective control technology.

3. Low coking design and operation is difficult to quantify, but is considered an effective means of minimizing GHG emissions. Assuming run life is extended by 25%, the

reduction in carbon dioxide emissions is equivalent to about 3 tons per year.

Step 4 - The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects.

Catalyst Disposal - Disposing of the catalyst instead of regeneration would generate additional solid waste and represent a significant cost burden for replacement catalyst. The replacement cost for the C3/C4 hydrogenation catalyst is \$1,500,000 for catalyst and \$400,000 for labor and is typically replaced every 5 years, if regenerated on a regular basis. It is anticipated there will be up to 2 to 3 regeneration events per year. Therefore, the total cost for replacing the catalyst rather than regenerating would be \$3,800,000 per year. This equates to \$294,000 per ton of GHG avoided. This does not include the disposal costs associated with removing the catalyst. Therefore, this control technology is not considered cost effective and is eliminated a possible control technology.

Reduced Air - Limiting the air feed would increase carbon monoxide while reducing CO_2. Carbon monoxide is a criteria pollutant with higher toxicity than CO_2. As mentioned earlier in the furnace decoking BACT section, limiting air could also result in incomplete catalyst regeneration. Carbon deposits reduce catalyst activity and reactor conversion which would lead to an increase in the frequency of regeneration events. This alternative is rejected as a control option for GHG emissions, since this could result in an increase in GHG emissions.

Low coking design and operation - Minimizing coke formation through the proper reactor design and operation to increase reactor run time between regeneration is considered cost effective and will have minimal energy and environmental effects.

Step 5- The selection of BACT. A proper reactor design with good operating practices will minimize coke formation and is considered BACT for C3/C4 Hydrogenation Reactor Regeneration Vent – MSS Activities. The reactor will be fed a C3/C4 distillate and a purified hydrogen stream to minimize contaminants and catalyst fouling. The reactor will be loaded with hydrogenation catalyst per catalyst supplier recommendations. Reactor temperatures, pressures and hydrogen concentrations will be maintained within recommended levels.

EPNs CR-13, 14, 17 and 16; Ethylene Plant Fugitive Emissions

Fugitive leakage from process equipment piping components associated with the proposed project includes methane and CO_2. The controlled emissions associated with the fugitive components have been estimated to be 3 tons/yr of methane and 0.1 Ton/yr of CO_2.

Step 1- The identification of available control technologies.

Potential GHG emission control technologies for the fugitive emissions are identified as follows:

a) Leakless Technology

b) Administration of a monitored leak detection and repair (LDAR) program for fugitive emissions.

c) Remote Sensing

d) Audio/Visual/Olfactory (AVO) Monitoring

Step 2 - The elimination of the technically infeasible alternatives. All of the identified alternatives are technically feasible.

Step 3 - The ranking of the remaining control technologies. The technologies identified in Step 1 that were not eliminated in Step 2 have been ranked based on the ability to reduce GHG emissions from fugitive emission sources.

1. The use of leakless technology such as barrier sealing systems for pumps and compressors, rupture discs for relief devices and bellows sealed valves is capable of 100% control for each source and each technology is considered the most effective control technology.

2. LDAR programs are typically used to control VOC emissions and can achieve up to 97% control of VOC emissions. Although not specifically designed for GHG emissions, they can be used to control methane emissions. Monitors typically used for Method 21 instrument monitoring cannot detect CO2 leaks. However, they can be utilized to determine methane leaks. It is assumed that the same control factors can be applied to methane emission sources. Therefore, this is the second most effective control technology.

3. Remote sensing using infrared imaging has proven effective for identification of leaks. The process has been the subject of EPA rulemaking for an alternative monitoring method to Method 21. Although effectiveness is likely comparable to that of EPA method 21, it has not been quantified. Therefore, this is the third most effective control technology.

4. AVO means of identifying leaks owes its effectiveness to the frequency of observation opportunities. These opportunities arise as technicians make inspection rounds. This

method cannot generally identify leaks at a low leak rate as instrumented readings can identify; however low leak rates have lower potential impacts than larger leaks.

Step 4 - The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects.

Leakless Technology - Leakless components, such as bellows valves, commonly only available in the smaller sizes, significantly more expensive, and are typically used in highly toxic or hazardous material service. Consequently, their overall effectiveness is limited. The marginal additional level of control that is achieved over an LDAR program from the use of leakless technology is minimal and not considered cost effective for VOC or GHG control. Additionally, this technology has not been adopted as LAER or BACT, or even in MACT standards. Therefore, this technology is considered impractical for control of GHG emissions.

LDAR instrument monitoring program- The TCEQ's most aggressive BACT-styled fugitive monitoring and maintenance program, 28MID with quarterly monitoring of flanges, is currently considered BACT for controlling fugitive VOC emissions at the existing site. It is more aggressive than the 28LAER program due to the quarterly flange monitoring. As part of this 28MID approach all pumps and compressor seals in light liquid service are vented to control or are designed with non-leaker technology. This LDAR program will be implemented to monitor via instrumented Method 21 monitored for piping components (valves, pumps, connectors, and compressors) that are in greater than 10% methane service.

Step 5 - The selection of BACT. The implementation of an instrumented monitoring system for components in methane service is considered BACT. In addition, OxyChem will install barrier seal systems on pumps and compressors in VOC services (which will have a significant amount of methane), and where technically feasible, install rupture discs beneath relief valves in VOC service (which will have a significant amount of methane) that discharge to the atmosphere. Implementing these design practices in addition to the proposed LDAR program is considered beyond BACT for fugitive emission sources for the proposed new Ethylene Plant.

The CO_2e emissions estimated from equipment leaks in new and modified piping and equipment amount to 66.19 tpy, or less than 0.02% of the total CO_2e emissions from the project. Tracking emissions against a numeric limit is considered infeasible due to the insignificant quantity of emissions expected and the unpredictability of component leaks. OxyChem proposes to follow the monitoring, recordkeeping, and repair practices of TCEQ 28MID LDAR program fugitive monitoring program to ensure the minimization of GHG emissions from LDAR components for components containing greater than 10% CH_4.

EPN CR-19 Hydrogen Vent

During periods in which the amount of fuel gas produced is greater than the fuel demand of the furnaces, excess fuel must be diverted from the fuel gas system. This is considered an intermittent stream and is estimated to emit up to 1.44 ton per year of methane or 30.24 tons per year CO_2e.

Step 1- The identification of available control technologies. Potential GHG emission control technologies for the hydrogen vent were identified as the follows:

a. Vent hydrogen to the atmosphere – Hydrogen can be vented to the atmosphere at a safe location to remove excess fuel from the fuel gas system.

b. Hydrogen venting to the Thermal Oxidizers – The hydrogen vent can be routed to the thermal oxidizers to combust the stream and generate steam from the heat of combustion.

c. Reduce heater firing efficiency – Furnace firing efficiency can be reduced by adding excess air to the furnaces which causes an increase in fuel consumption per unit of production.

d. Hydrogen venting to the flares – The hydrogen vent can be routed to the flare systems to combust the stream.

Step 2 - The elimination of the technically infeasible alternatives. Reducing heater firing efficiency is not technically feasible and has been eliminated as an alternative. Reducing the firing efficiency of the heaters would require changes to the heater design. These design changes would affect the firing efficiency of the heater for 100% of the operating time while the need to burn additional fuel is only needed for an estimated 60 days per year. The remaining alternatives are considered to be technically feasible.

Step 3 - The ranking of the remaining control technologies. The technologies identified in Step 1 that were not eliminated in Step 2 have been ranked based on the ability to reduce GHG emissions from the hydrogen vent.

1. Venting hydrogen to the thermal oxidizers accomplishes the objective of removing fuel from the fuel gas system and generates steam from the heat of combustion. Venting hydrogen to the thermal oxidizers will increase emissions of CO_2 by 4.53 tons/yr and NO_x by 4.33 tons/yr while reducing methane emissions by at least 99.9%. This option would be the most effective technology of reducing GHG emissions as it would make use of the heat energy.

2. Hydrogen venting to the high pressure flare system would reduce methane emissions by 99% through combustion, but would increase CO_2 emissions by 4.53 tons/yr and NO_x emissions by 9.95 tons/yr. Additionally, there would be no heat recovery associated with this control option. This option would be the second most effective technology of reducing GHG emissions.

3. Venting the hydrogen to the atmosphere accomplishes the objective of removing fuel from the fuel gas system with low impact to the operating equipment and environment. Venting hydrogen to the atmosphere will emit 1.44 tons per year of methane and zero tons of NOx. This option has the lowest impact to the environment relative to criteria pollutants with minimal increase in GHG emissions relative to the project total emissions.

Step 4 - The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects.

Venting hydrogen to the thermal oxidizers - Venting hydrogen to the thermal oxidizers will increase emissions of CO_2 by 4.53 tons/yr and NOx by 4.33 tons/yr and will reduce methane emissions to less than 0.01 tons per year or 0.03 tons of CO_2e. This option does allow for energy recovery in the form of steam production which would provide some economic return. However, the currently designed thermal oxidizers associated with the Ethylene Plant do not have the current capacity to accept this stream and be able to control the normal Ethylene Plant vent streams. Therefore, two additional thermal oxidizers would be required to control the capacity of the hydrogen vent stream. Each thermal oxidizer is estimated to cost $5,000,000 in capital costs, based on recent vendor estimates to control 1.44 tons of methane emissions. This equates to nearly $7,000,000 per ton of methane removed, not including operating or piping costs to the thermal oxidizers. Therefore, this control technology is not considered cost effective and is eliminated as a potential control technology.

Venting fuel gas to the flare system - Venting fuel gas to the flare system would increase CO_2 emissions by 4.53 tons/yr and NO_x emissions by 9.95 tons/yr while reducing methane emissions to 0.01 tons per year or 0.3 tons of CO_2e. There is no economic or energy advantage to this option. NOx is a heavy regulated criteria pollutant. Therefore, this option would create more pollution than it would eliminate (i.e. 9.95 tons of NOx and 4.53 tons per year CO2, while reducing 1.44 tons per year of methane). Therefore, this option will have highly negative environmental impact and is eliminated as a potential control technology.

Venting hydrogen to the atmosphere - Venting hydrogen to the atmosphere will emit 1.44 tons per year of methane and zero tons per year NOx. This option will have the lowest environmental impact.

Step 5 - The selection of BACT. Venting hydrogen to the atmosphere is considered BACT. The amount of fuel gas generated by the process is based on engineering evaluation of the proposed plant design, and the calculated fuel gas balance for this unit is very close to being in balance with no excess fuel gas. With the potential that there will be excess fuel gas generation, the design must anticipate this possibility and provide a means of handing the excess.