GHG PSD PERMIT APPLICATION

DCP Midstream, LP
Jefferson County NGL Fractionation Plant

Prepared for:

DCP Midstream, LP
Houston, Texas

FOR SPIRIT ENVIRONMENTAL, LLC

Stuart Doss

Stuart Doss

Brad Herrin

Brad Herrin

12.117.00

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17350 State Highway 249
Suite 249
Houston, Texas 77064

SPIRIT ENVIRONMENTAL

281- 664-2490 (main)
281- 664-2491 (fax)
www.spiritenvironmental.com

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1.0 INTRODUCTION

DCP Midstream, LP (“DCP”) is submitting this air permit application to the United States Environmental Protection Agency (“USEPA”) Region 6, proposing to construct a Natural Gas Liquids (“NGL”) Fractionation facility. The facility will be located in Jefferson County, Texas approximately 2 miles south of Beaumont, Texas. The facility will be referred to as the “Jefferson County NGL Fractionation Plant.” This document represents a request by DCP for USEPA Region 6 to issue a Greenhouse Gas (“GHG”) Prevention of Significant Deterioration (“PSD”) air permit to construct the proposed facility.

The two digit standard industrial classification (“SIC”) codes for the Jefferson County NGL Fractionation Plant and the existing DCP West Beaumont Gas Plant are both 13 and both facilities are under common control of DCP. However, they are not located within 1/4-mile of each other and are not operationally dependent. Because these two facilities are not located within 1/4 mile of each other and are not operationally dependent, they are not considered adjacent for purposes of New Source Review (“NSR”) permitting. Therefore, the two facilities and will be considered separate stationary sources.

The Jefferson County NGL Fractionation Plant has the potential to emit more than 100,000 tons per year (“tpy”) of carbon dioxide equivalent (“CO_2e”); therefore, the facility is considered a new major stationary source of GHGs. Because the Jefferson County NGL Fractionation Plant project will be a new major stationary source, it requires a GHG PSD air construction permit from USEPA Region 6. The Jefferson County NGL Fractionation Plant does not have the potential to emit more than 100 tpy of carbon monoxide (“CO”), 40 tpy of nitrogen oxides (“NO_X”), 40 tpy of volatile organic compounds (“VOC”), 40 tpy of sulfur dioxide (“SO_2”), 15 tpy particulate matter equal to or less than 10 microns in diameter (“PM_{10}”), 10 tpy particulate matter equal to or less than 2.5 microns in diameter (“$PM_{2.5}$”), 10 tpy hydrogen sulfide (“H_2S”), or 10 tpy total reduced sulfur compounds (“TRS”); therefore, these non-GHG pollutants do not exceed the PSD significant emission thresholds and will not require PSD review. Because the new site will not exceed the significant emission thresholds for non-GHG pollutants, a minor source air construction permit application will be submitted to the Texas Commission on Environmental Quality ("TCEQ") to authorize emissions of these pollutants. Specific PSD applicability for the proposed facility is discussed in Section 4.0 of this application.

1.1 APPLICATION OVERVIEW

The purpose of this document is to provide all technical and administrative information necessary for the USEPA Region 6 to issue a GHG PSD air construction permit to DCP for the construction of the proposed Jefferson County NGL Fractionation Plant. The facility will consist of two process trains with a nominal capacity of approximately 75,000 barrels per day ("bpd") each of Y-grade NGL feedstock. Actual throughput of Y-grade NGL feedstock for each train is dependent on the composition of the feedstock and the sales specifications for the five purity products and will vary over time. Therefore, each process train is capable of higher feedstock throughput than the nominal capacity, without exceeding the limitations represented in this permit application. The facility will separate Y-grade NGL feedstock into the purity products ethane, propane, normal butane, isobutane, and natural gasoline using a fractionation process. The feedstock will be supplied to the facility via a pipeline. The fractionated NGL products will be transported to DCP customers via pipeline.

The remainder of this application includes the information necessary to evaluate the GHG air emissions associated with the proposed Jefferson County NGL Fractionation Plant. Section 1.2 addresses the facility location, Section 1.3 provides a summary of required permit forms and tables, and Section 1.4 provides information regarding correspondence with the applicant. Section 2.0 contains a Process Description, Section 3.0 provides GHG Emissions Estimates for the proposed Jefferson County NGL Fractionation Plant, Section 4.0 addresses Regulatory Applicability associated with GHG emissions, and Section 5.0 addresses Best Available Control Technology ("BACT") associated with GHG emissions. Section 6.0 contains attachments to the application, including permit forms and tables (Attachment A), detailed GHG emission estimates (Attachment B), supporting documentation (Attachment C), and supporting BACT information (Attachment D).

1.2 SITE AND UNIT LOCATION

Figure 1-1 provides the location of the proposed site relative to the immediate surrounding area. This figure illustrates the property boundary of the proposed Jefferson County NGL Fractionation Plant and an outline of the process area within the proposed property boundary.

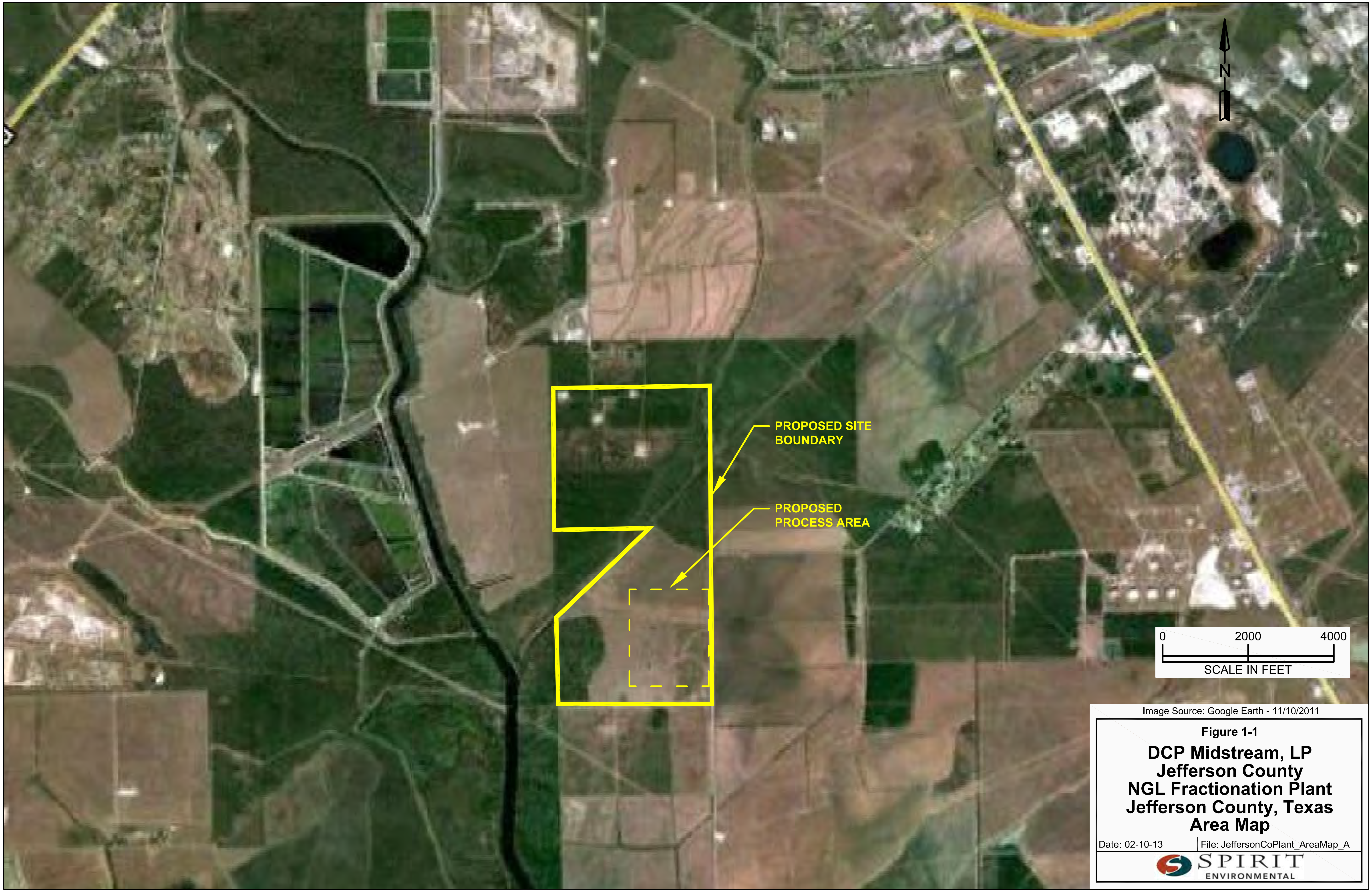

Image Source: Google Earth - 11/10/2011

Figure 1-1

DCP Midstream, LP
Jefferson County
NGL Fractionation Plant
Jefferson County, Texas
Area Map

Date: 02-10-13 File: JeffersonCoPlant_AreaMap_A

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1.3 PERMIT FORMS AND INFORMATION

DCP understands that the USEPA Region 6 does not currently have forms for PSD air permit applications and has requested that the permit applicant use the appropriate TCEQ forms. Therefore, DCP has included the appropriate TCEQ permit forms and tables in this application. Section 6, Attachment A includes Form PI-1 Permit Application, Table 1(a) Emission Point Summary, Table 4 Combustion Units, Table 6 Boilers and Heaters, Table 8 Flare Systems, and Table 29 Reciprocating Engines.

1.4 CORRESPONDENCE WITH APPLICANT

Please direct all email/mail correspondence and telephone requests regarding review of the permit application to:

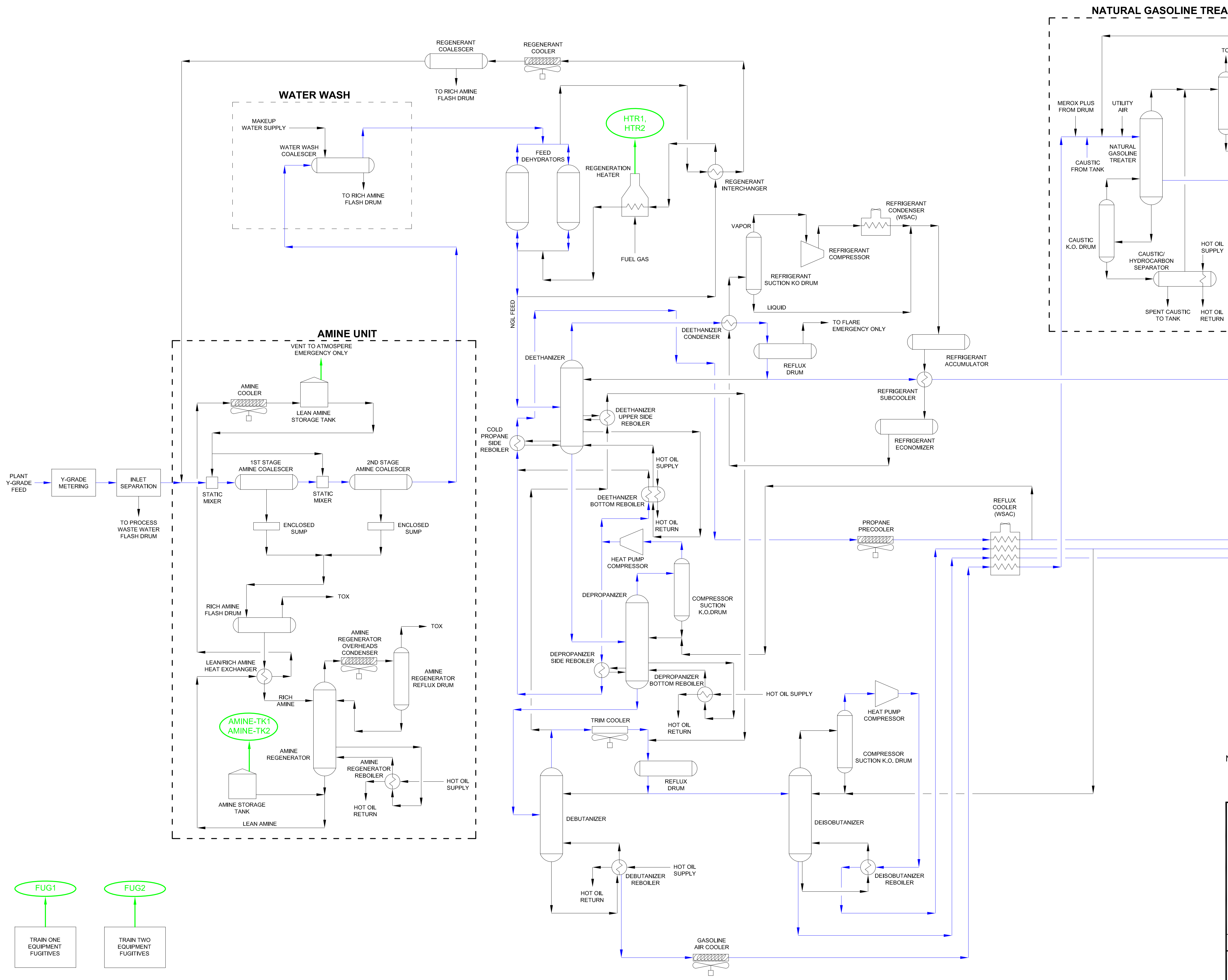
Ms. Lynn Ward
Senior Environmental Specialist
DCP Midstream, LP
662 South Shelby
Carthage, TX 75633
LCWard@DCPMidstream.com
(903) 694-4114

Please send a copy of all email/mail correspondence to:

Mr. Brad Herrin
Spirit Environmental, LLC
17350 SH 249, Ste. 249
Houston, TX 77064
BHerrin@SpiritEnv.com
(281) 664-2820

2.0 PROCESS DESCRIPTION

DCP is seeking to authorize the construction of a two-train NGL fractionation plant to separate a Y-grade NGL feed into liquid products (ethane, propane, normal butane, isobutane, and natural gasoline). The facility will be designed with a nominal capacity of approximately 75,000 bpd per train and includes amine treating, natural gasoline treating, molecular sieve dehydration, hot oil as the primary heat source, refrigerant propylene and wet surface air coolers/condensers (“WSAC”) for cooling and condensation, a thermal oxidizer (“TO”) for control of waste gas streams, and an emergency flare. Compression for the propylene refrigeration and process heat pumps will be accomplished using compressors powered by electric motors. The hot oil for the process is heated using a natural gas-fired heater for each train. Heat exchangers will be incorporated throughout the process to take advantage of heating and cooling efficiencies. All of the reboilers described in Sections 2.1 through 2.5 are not fired heaters, but instead heat exchangers which use heat from either within the process (from another process stream) and/or from hot oil heated by the natural gas-fired heaters described in Section 2.7. The feed to the NGL facility will be supplied from existing and proposed pipelines and underground storage. The product sales will also consist of pipeline delivery or delivery to underground storage. Figures 2-1 and 2-2 provide process flow diagrams for the Jefferson County NGL Fractionation Plant.



LEGEND

TOX - THERMAL OXIDIZER

→ - MAIN PROCESS LINE

NOTE: THIS PROCESS FLOW DIAGRAM REPRESENTS ONE TRAIN AT THE PROPOSED NGL FRACTIONATION PLANT. THE PLANT WILL CONSIST OF TWO SIMILAR TRAINS. EMISSION POINTS INCLUDED ON THIS DIAGRAM REPRESENT BOTH TRAINS.

Figure 2-1

DCP Midstream, LP
Jefferson County NGL
Fractionation Plant
Process Flow Diagram

Date: 02-26-2013	File: JeffersonCoPlant_PFD_A

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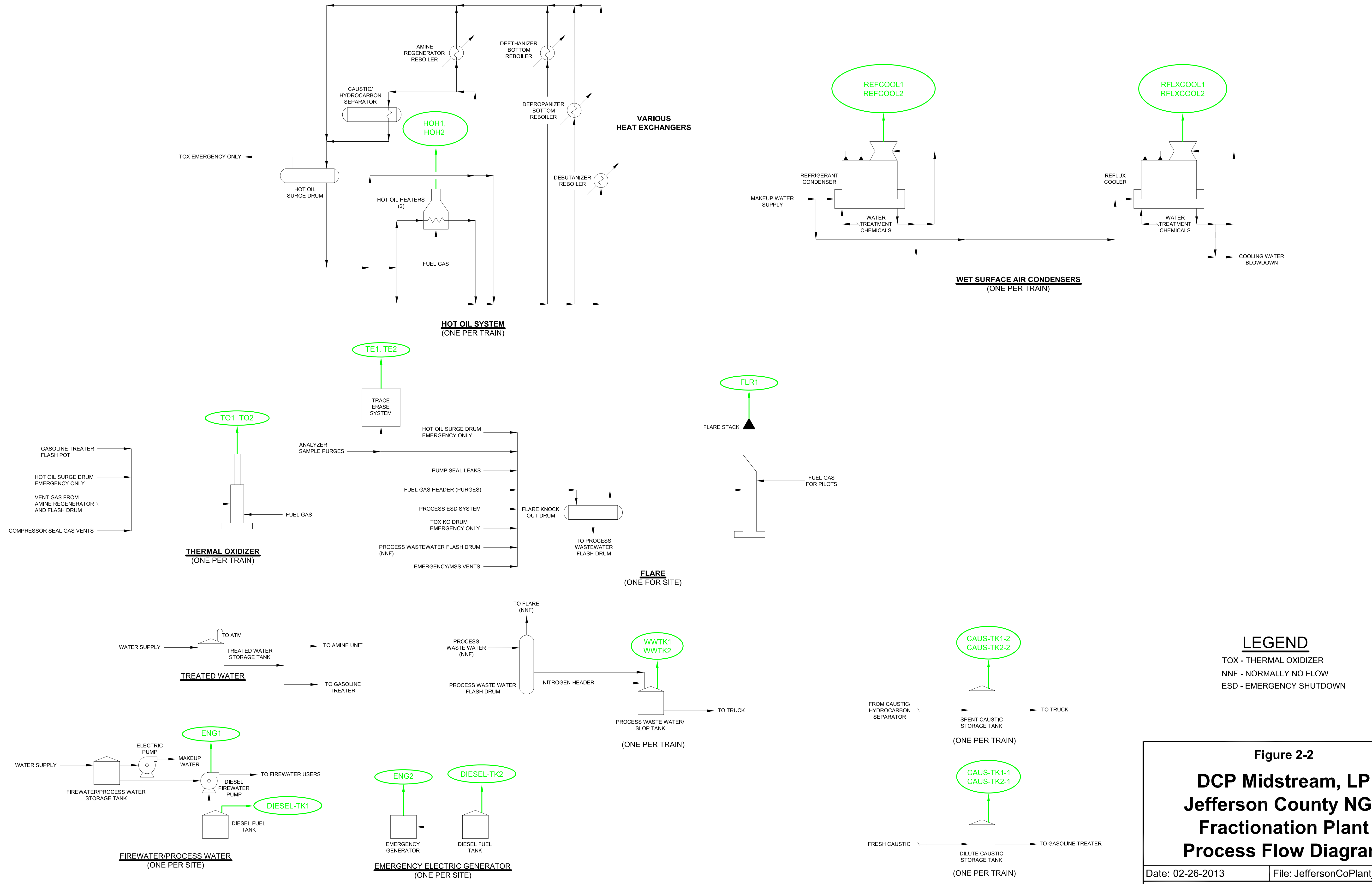

LEGEND

TOX - THERMAL OXIDIZER
NNF - NORMALLY NO FLOW
ESD - EMERGENCY SHUTDOWN

Figure 2-2

DCP Midstream, LP
Jefferson County NGL Fractionation Plant
Process Flow Diagram

Date: 02-26-2013	File: JeffersonCoPlant_PFD_A

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2.1 INLET SEPARATION/AMINE TREATING

The Y-grade NGL feed stock will be metered prior to entering the facility. After metering, the Y-grade NGL feed stock will go through inlet separation/filtration prior to treating for carbon dioxide (“CO_2”) removal in the liquid-to-liquid amine static mixers and coalescers. Particulates and free water will be removed in inlet separation/filtration. Free water is routed to the process waste water flash drum, which vents to the flare. Process waste water from the process waste water flash drum is routed to the process waste water/slop storage tank and loaded out to trucks for off-site disposal as necessary.

After filtering and separation, the NGL feed is contacted with fresh amine in two separate stages of static mixing and separation to remove CO_2 from the NGL feed. The CO_2 will be removed by the amine solvent as the CO_2 molecules react with the amine molecules, becoming “rich” amine. The denser amine phase settles by gravity to a sump vessel below each coalescer. The rich amine from each sump vessel flows to the rich amine flash drum and filters to remove any dissolved, entrained, or solid contaminants. The treated NGL from the second amine coalescer is routed to a water wash coalescer where any amine solution that is carried over is removed and routed to the rich amine flash drum. Light hydrocarbons that flash in the rich amine flash drum are routed to the TO. The rich amine is then warmed using the lean/rich amine heat exchanger prior to entering the amine regenerator, where the amine is regenerated using heat provided by the hot oil system to vaporize the CO_2 and purify the amine. The amine that exits the bottom of the amine regenerator is now “lean,” as the CO_2 has been removed.

Heat for the amine regenerator is provided by a heat exchanger using hot oil from the plant hot oil system. The overhead vapor from the amine regenerator is routed through a condenser to the amine regenerator reflux drum, where condensed liquid consisting of mostly water is collected and pumped back to the amine regenerator as reflux. The overhead gas stream, consisting of mostly CO_2 with some minor amount of sulfur compounds and hydrocarbons, is routed to the TO for destruction of the hydrocarbons.

The lean amine from the bottom of the amine regenerator is cooled by routing back through the lean/rich amine heat exchanger and an additional cooler prior to entering the lean amine storage tank. The cooled lean amine is pumped from the lean amine storage tank back to the two amine static mixers and coalescers, where the process of CO_2 removal from the Y-grade NGL begins again. An amine storage tank provides fresh amine to the process to replace any amine lost through the regeneration process. Following removal of the CO_2 and free water, the NGL feed from the water wash coalescer is routed to the Dehydration section of the process.

2.2 DEHYDRATION UNIT

After amine treating, the NGL will be routed through one bed of a two-bed molecular sieve dehydration unit to remove any equilibrium water. Each molecular sieve tower is packed with a desiccant that removes water by a process called adsorption. During adsorption, water molecules are adsorbed to the desiccant due to the greater attraction of the water molecule. When the bed is saturated with water, hot dry gas is passed through the bed in order to vaporize the water and regenerate the molecular sieve. The hot dry gas needed to regenerate the bed is a slip stream of the dry Y-grade feed that is vaporized by a natural gas-fired heater before it enters the dehydrator bed. The vaporized NGL, which now contains water vapor, is cooled in the regenerant interchanger where heat is transferred from the hot, wet stream to the dry Y-grade slip stream. Final cooling and condensation of water occurs in the regenerant cooler. The stream from the regenerant cooler is routed to the regenerant coalescer where the liquid water is separated and routed to the rich amine flash drum. The remaining Y-grade from the regenerant coalescer is recycled to the inlet of the first amine static mixer and coalescer in the amine treating section of the process, where it combines with the NGL feed. Any free water in the feed from the recycled regenerant stream is removed by the amine coalescers downstream of each amine static mixer.

Under normal operating conditions, one of the two dehydrator towers will be in adsorption while the other is in regeneration. After the NGL leaves the molecular sieve tower where the water has been removed, the NGL is sent to the Fractionation section of the process for separation into purity products.

2.3 FRACTIONATION

The NGL feed is sent from the dehydrators to the deethanizer column. The deethanizer condenser uses propylene refrigerant to cool and condense the overhead vapors. The condensed liquid is collected in the deethanizer reflux accumulator. A portion of the liquid is sent back to the deethanizer as reflux with the remainder exiting the reflux accumulator as the ethane product. The ethane product is used to cool propylene refrigerant in the refrigerant subcooler before the ethane is sent through the metering section of the plant and out to the ethane pipeline.

The deethanizer has two side reboiler, process-to-process, heat exchangers. The deethanizer upper side reboiler is heat integrated with the debutanizer overhead vapor. The lower side (cold propane) reboiler is heat integrated with a combined heat pump stream from the deethanizer bottom reboiler and the depropanizer side reboiler. The deethanizer bottom reboiler uses a combination of hot oil from the hot oil system and hot propane vapor from the depropanizer heat pump compressor discharge stream as a heat source. The bottoms product from the deethanizer is sent as feed to the depropanizer.

The depropanizer overhead vapors are routed to the depropanizer heat pump compressor suction knock out (“KO”) drum. Condensate from the suction KO drum is pumped back to the depropanizer as reflux. Vapors from the suction KO drum are compressed by the electric powered depropanizer heat pump compressor. The discharge stream of the depropanizer heat pump compressor is split and routed to the depropanizer side reboiler and the deethanizer bottom reboiler where heat from compression is used in these process-to-process heat exchangers. The heat pump propane streams from the depropanizer side reboiler and the deethanizer bottom reboiler are then rejoined and additional heat is recovered in the cold propane side reboiler. The stream from the cold propane side reboiler is condensed in the propane precooler (fin fan cooler) and the reflux cooler WSAC. A portion of the liquid is sent back to the depropanizer as reflux, and the remainder exits the reflux cooler WSAC as propane product. This propane product is sent through the metering section of the plant and out to the propane pipeline. The depropanizer bottom reboiler uses hot oil from the hot oil system as a heat source. The bottoms product from the depropanizer is sent as feed to the debutanizer.

The debutanizer overhead vapor is fully condensed in the deethanizer upper side reboiler, which provides heat to the deethanizer. During times of abnormal operation, such as startup/shutdown, when the reboiler duty requirements are low, trim cooling, which can contribute up to 50% of the normal duty, can be provided by the debutanizer trim cooler (fin fan cooler). The condensed liquid is collected in the debutanizer reflux accumulator. A portion of the liquid is sent back to the debutanizer as reflux, and the remainder is sent as feed to the deisobutanizer. The debutanizer reboiler uses hot oil from the hot oil system as a heat source. A natural gasoline stream from the debutanizer reboiler is sent to the natural gasoline air cooler (fin fan cooler) and then to the reflux cooler WSAC to be further cooled. The natural gasoline stream from the reflux cooler WSAC is routed to the Natural Gasoline Treating section.

Feed from the debutanizer reflux accumulator enters the deisobutanizer for separation into normal butane and isobutane. The deisobutanizer overhead vapors are routed to the deisobutanizer heat pump compressor suction KO drum. Condensate from the suction KO drum is pumped back to the deisobutanizer as reflux. Isobutane vapors from the suction KO drum are compressed by the electric powered deisobutanizer heat pump compressor. The outlet stream of the deisobutanizer heat pump compressor is routed through the deisobutanizer reboiler (process-to-process heat exchanger) where heat from compression is recovered and the heat pump stream is condensed. The heat pump stream from the deisobutanizer reboiler is routed to the reflux cooler WSAC to subcool the liquid. A portion of the condensed subcooled liquid is sent back to the deisobutanizer as reflux with the remainder exiting the reflux accumulator as the isobutane product. The isobutane product is sent through the metering section of the plant and out to the isobutane pipeline.

The bottoms product from the deisobutanizer is normal butane, which is cooled in the reflux cooler WSAC. The normal butane product from the reflux cooler WSAC is sent through the metering section of the plant and out to the normal butane pipeline.

2.4 NATURAL GASOLINE TREATING

The natural gasoline leaving the reflux cooler WSAC is treated to convert trace amounts of thiophenes and mercaptans into disulfides. Caustic solution (from the caustic storage tank), Merox plus (from drums), heated water, and air are injected into the natural gasoline stream upstream of the natural gasoline treater. The combined stream is introduced into the top of the natural gasoline treater where the liquid flows down through the treater and the spent air is discharged from the top of the natural gasoline treater. The spent air is routed to the natural gasoline treater flash pot. The spent caustic is separated from the natural gasoline at the bottom of the natural gasoline treater. After leaving the natural gasoline treater, the natural gasoline product is filtered to remove any fines and then sent through the metering section of the plant and out to the natural gasoline pipeline.

The spent caustic from the natural gasoline treater is routed to the natural gasoline treater caustic KO drum. The lighter natural gasoline liquid from the top of the KO drum is routed back to the bottom of the natural gasoline treater. The heavier (aqueous) liquid from the bottom of the KO drum is routed to the caustic/hydrocarbon separator. Any dissolved or entrained hydrocarbons are removed in the caustic/hydrocarbon separator by heating the liquid using a heating coil with the heat provided by the hot oil system. Vapor from the caustic/hydrocarbon separator is routed to the natural gasoline treater flash pot. The vent from the natural gasoline treater flash pot is routed to the TO for control. Liquid from the natural gasoline treater flash pot is routed back to the natural gasoline treater. Liquid from the caustic/hydrocarbon separator is routed to the spent caustic storage tank. Spent caustic from the spent caustic storage tank is trucked off-site for disposal as required.

2.5 PROPYLENE REFRIGERATION

The Propylene Refrigeration System is a closed-loop system that supplies cold propylene liquid refrigerant to the deethanizer condenser. Propylene refrigerant vapor is compressed by a compressor powered by an electric motor. Hot compressed propylene vapor passes through the refrigerant condenser WSAC where it is cooled and condensed to a liquid. The condensed propylene is mixed with liquid pumped from the refrigerant suction KO drum. The combined propylene stream flows to the refrigerant accumulator after which it is further cooled in the refrigerant subcooler by the cold ethane product. The refrigerant subcooler is a process-to-process heat exchanger that recovers energy from the ethane product stream, thereby reducing compression requirements. The liquid propylene is then sent to the refrigerant economizer. Liquid propylene from the economizer is used in the deethanizer condenser to condense the overhead vapor (ethane) from the top of the deethanizer tower. The resulting propylene vapor from the deethanizer condenser is recycled back to the refrigerant compressor via the refrigerant suction KO drum. Liquid from the refrigerant suction KO drum is sent to the refrigerant accumulator.

2.6 WET SURFACE AIR COOLERS/CONDENSERS

The WSACs are used to cool and/or condense propylene refrigerant, propane, isobutane, normal butane, and natural gasoline. These cooler/condensers operate by having warm process fluids flow through tubes which are sprayed with water. Air is drawn down across the tubes by a fan, creating a cooling effect by evaporating the water. The water not evaporated is collected in a basin and pumped back to the top of the tower to begin the process again. The evaporated water and air are discharged from the top of the condenser by a fan to the atmosphere. These devices operate under the same principle as a water cooling tower; however, by using direct cooling of the process fluids, they can be cooled to lower temperatures.

2.7 HOT OIL SYSTEM

As shown in Figure 2-2, the hot oil system is a closed-loop system that supplies hot oil to various heat exchangers. The hot oil surge drum is a nitrogen-blanketed vessel that collects all the hot oil returns. The hot oil pumps are used to pump hot oil to the hot oil heater. The hot oil heater is natural gas-fired. Heat exchangers for the deethanizer reboiler, depropanizer reboiler, debutanizer reboiler, amine regenerator reboiler, and the caustic/hydrocarbon separator heating coil all utilize hot oil as the heat source.

2.8 FUEL GAS SYSTEM

Sweet natural gas is supplied to the facility for the gas-fired equipment. The natural gas coming into the plant is depressured from pipeline transmission pressure to fuel gas distribution pressure at the fuel gas KO drum. The natural gas from the KO drum flows into a fuel gas header.

2.9 FLARE

The Flare System collects relief valve discharges, other emergency vents, intermittent vents, and maintenance, startup, and shutdown ("MSS") vents. Vapor is sent to the flare KO drum and liquids are separated and pumped from the flare KO drum to the process waste water flash drum (which vents to the flare). During normal operations there is no other flow to the process waste water flash drum. Liquids from the process waste water flash drum are pumped to the process water/slop storage tank and then trucked off-site for disposal as required. The flare is equipped with natural gas-fired continuous pilots, several continuous natural gas purges on the flare header, and a flare stack blower ensuring a smokeless design. The presence of pilot flames is continuously monitored by a thermocouple or the equivalent. The flare is designed as an emergency flare. Emissions associated with minor intermittent vents and MSS will also be routed to the flare.

2.10 THERMAL OXIDIZER

Each train will be equipped with a TO that includes a gas-fired burner rated at 5 million British thermal units per hour ("MMBtu/hr") that will be used to combust three waste gas streams from the process during normal operation. The first waste stream consists of flash gas from the rich amine flash drum and acid gas from the amine regeneration system. This stream is comprised of primarily CO_2 with some sulfur species and VOCs. The second waste stream is the vent from the natural gasoline treater flash pot containing small amounts of various mercaptans, sulfur compounds, and hydrocarbons. The third stream is composed of various seal gas vents from compressors within the process which contain various hydrocarbons. The TO will operate with a destruction efficiency of 99.9% for VOC and sulfur compounds. The combustion chamber will maintain a sufficient temperature (actual temperature to be based on source testing) and a residence time of 0.5 seconds or greater to ensure 99.9% destruction efficiency.

2.11 PRODUCT DELIVERY

All products from the Jefferson County NGL Fractionation Plant will be delivered off-site via pipeline. Each product will go through a filtering and metering skid prior to entering the product pipeline. Each product will be quality checked prior to entering the respective metering skid and will be sent to an off-site purity product storage facility or to sales via pipeline.

3.0 EMISSION RATE ESTIMATES

This section of the application provides detailed GHG emission rate estimates for each source associated with the Jefferson County NGL Fractionation Plant. Sections 3.3 through 3.9 contain detailed normal operation emission rate estimates, while emission rates due to MSS activities are provided in section 3.10. Figures 2-1 and 2-2 in Section 2.0 are process flow diagrams that illustrate the location within the process of each emission point. Figure 3-1 is a facility plot plan that provides the proposed physical location of each emission point within the Jefferson County NGL Fractionation Plant. Please note this application addresses emission rates of CO_2, methane (“CH_4”), and nitrous oxide (“N_2O”) only. Some sources, such as the WSACs and the storage tanks, do not emit GHGs; therefore, these sources are not included in these emission rate estimates. Emission rates of all GHG pollutants from each source for both normal and MSS operations are summarized at the end of each subsection. Detailed GHG emission estimate calculations are provided in Section 6.0, Attachment B. Emission rates of other regulated NSR pollutants are addressed in the minor NSR permit application to be submitted to the TCEQ.

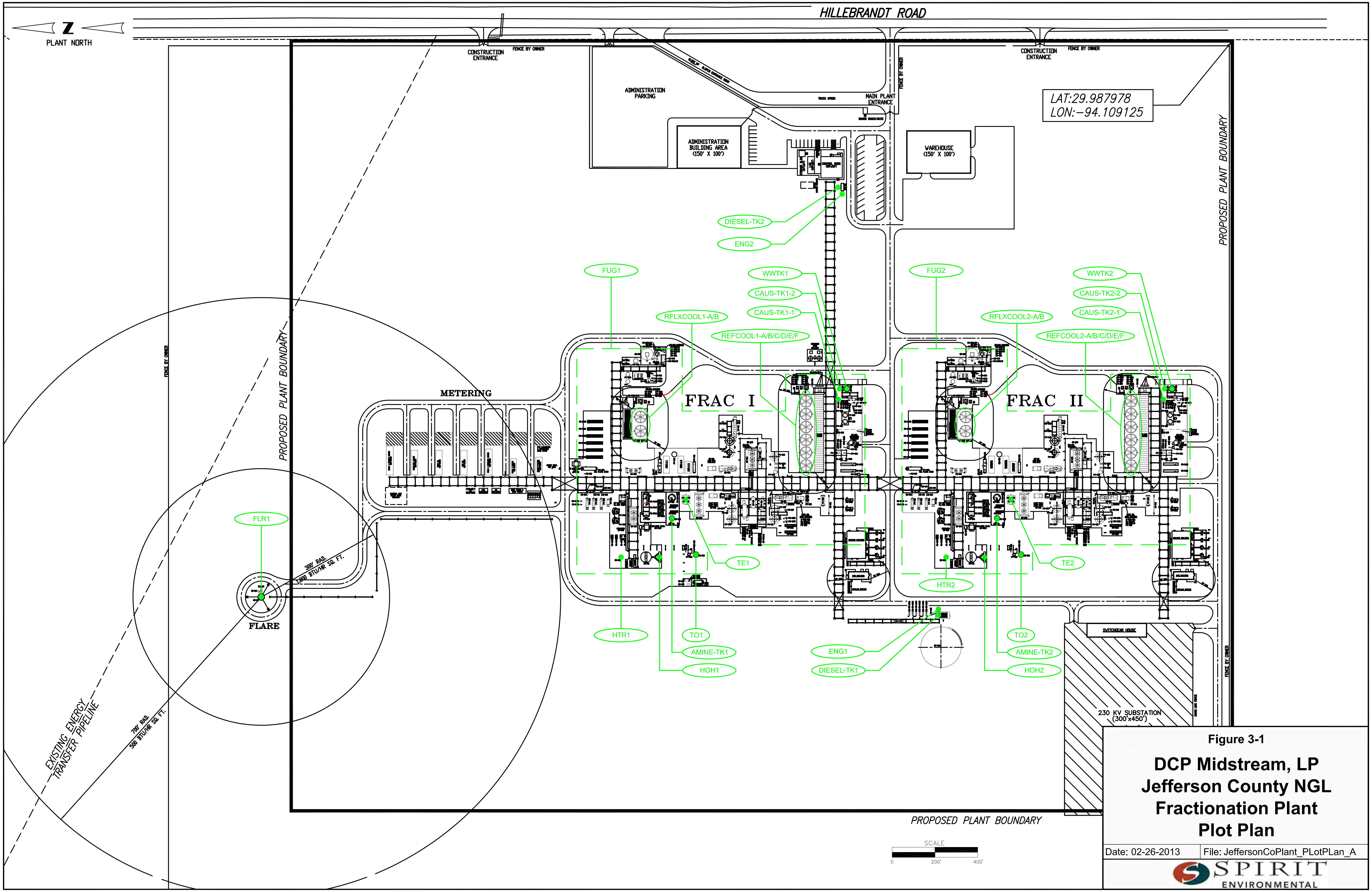

Figure 3-1

DCP Midstream, LP
Jefferson County NGL
Fractionation Plant
Plot Plan

Date: 02-26-2013	File: JeffersonCoPlant_PLotPLan_A

SPIRIT ENVIRONMENTAL

3.1 COMBUSTION EMISSION FACTOR SELECTION

3.1.1 COMBUSTION OF NATURAL GAS

Two sets of published emission factors are available for use in estimating the GHG emission rates from combustion sources fired using natural gas: the set published in 40 Code of Federal Regulations (“CFR”) Part 98, Subpart C, Tables C-1 and C-2 [the Mandatory Reporting Rule (“MRR”)] and the set published in AP-42 (Chapter 1 for the heaters, flare, and TOs; Chapter 3 for the engines). To maintain consistency across all reporting and recordkeeping requirements and programs, the combustion emission rates are estimated using factors from the MRR only. The MRR emission factors for natural gas combustion use a default high heating value (“HHV”) of 1,028 British thermal units per standard cubic foot (“Btu/scf”).

The emission factors for natural gas are converted from kilograms per million British thermal units (“kg/MMBtu”) to pounds per million standard cubic foot (“lb/MMscf”) as follows (using CO_2 as an example):

$$\left(\frac{53.02\text{ kg }CO_2}{\text{MMBtu}}\right)\times\left(\frac{2.2046\text{ lb }CO_2}{\text{kg }CO_2}\right)\times\left(\frac{1\text{ MMBtu}}{10^6\text{ Btu}}\right)\times\left(\frac{1{,}028\text{ Btu}}{\text{scf}}\right)\times\left(\frac{10^6\text{ scf}}{1\text{ MMscf}}\right)=120{,}161\ \frac{\text{lb }CO_2}{\text{MMscf}}$$

3.1.2 COMBUSTION OF WASTE GAS

GHG emissions for the combustion of waste gas are estimated using the methodology in 40 CFR Part 98, Subpart W. CO_2 emissions are estimated assuming all carbon in the waste gas streams is converted into CO_2 during combustion. CH_4 emissions are estimated using the destruction removal efficiency (“DRE”) of the specific control device, to account for the amount of CH_4 in the waste gas stream that is not destroyed. N_2O emissions are estimated using the emission factor 1.0×10^{-4} kg/MMBtu and a waste gas heating value of 1.235×10^{-3} MMBtu/scf from Equation W-40 in 40 CFR Part 98, Subpart W.

3.2 CARBON DIOXIDE EQUIVALENT

The CO_2e emission rates for each source are estimated by multiplying the individual GHG emission rate by the appropriate global warming potential ("GWP") as specified in 40 CFR Part 98, Subpart A, Table A-1. Table 3.2-1 presents the GWP of each GHG.

Table 3.2-1
GWP of Selected GHGs

CO_2	CH_4	N_2O
1	21	310

For example, the hourly CO_2e emission rate from one hot oil heater (See Section 3.3) is estimated as follows:

$$\left(\frac{21{,}366.09 \text{ lb } CO_2}{\text{hr}}\right) \times (1) + \left(\frac{0.40 \text{ lb } CH_4}{\text{hr}}\right) \times (21) + \left(\frac{0.04 \text{ lb } N_2O}{\text{hr}}\right) \times (310) = 21{,}386.89 \ \frac{\text{lb}}{\text{hr}} CO_2e$$

3.3 HOT OIL HEATERS

The hot oil system at the Jefferson County NGL Fractionation Plant will use one heater per train to heat an oil medium to deliver heat to the rest of the plant. Each hot oil heater is fired using natural gas delivered via pipeline. Combustion of this fuel within the hot oil heater results in GHG emissions.

3.3.1 CO_2, CH_4, AND N_2O EMISSION RATE ESTIMATES

The CO_2, CH_4, and N_2O emission factors are from the MRR, as discussed in Section 3.1. The emission factor for each GHG is presented in Table 3.3-1.

The E_{MAX} of CO_2, CH_4, and N_2O from each hot oil heater using the maximum hourly firing rate of 179 MMBtu/hr is estimated as follows (using CO_2 as an example):

$$E_{MAX}\left(\frac{\text{lb}}{\text{hr}}\right) = F \div HV \times HR$$
$$= \left(\frac{120{,}161\ \text{lb}\ CO_2}{\text{MMscf}}\right) \times \left(\frac{\text{scf}}{1{,}006.68\ \text{Btu}}\right) \times \left(\frac{179\ \text{MMBtu}}{\text{hr}}\right)$$
$$= 21{,}366.09\ \frac{\text{lb}}{\text{hr}}\ CO_2$$

Where F = Emission Factor (lb CO_2/MMscf)
HV = Heating Value of Natural Gas (Btu/scf)
HR = Maximum Heater Firing Rate (MMBtu/hr)

The E_{ANN} of each compound from each hot oil heater is based on 8,760 operating hours per year at an average firing rate of 150 MMBtu/hr. The emission rates are estimated as follows (using CO_2 as an example):

$$E_{ANN}\ (\text{tpy}) = F \div HV \times HR \times \left(\frac{8{,}760\ \text{hrs}}{\text{yr}}\right) \times \left(\frac{1\ \text{ton}}{2{,}000\ \text{lbs}}\right)$$
$$= \left(\frac{120{,}161\ \text{lb}\ CO_2}{\text{MMscf}}\right) \times \left(\frac{\text{scf}}{1006.68\ \text{Btu}}\right) \times \left(\frac{150\ \text{MMBtu}}{\text{hr}}\right) \times \left(\frac{8{,}760\ \text{hrs}}{\text{yr}}\right) \times \left(\frac{1\ \text{ton}}{2{,}000\ \text{lbs}}\right)$$
$$= 78{,}421.92\ \text{tpy}\ CO_2$$

Where F = Emission Factor (lb CO_2/MMscf)
HV = Heating Value of Natural Gas (Btu/scf)
HR = Average Heater Firing Rate (MMBtu/hr)

The emission rate of each GHG per hot oil heater is summarized in Table 3.3-1.

Table 3.3-1
Hot Oil Heater GHG Emission Rates

Pollutant	Emission Factor (lb/MMscf)	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	120,161	21,366.09	78,421.92
CH_4	2.27	0.40	1.48
N_2O	0.23	0.04	0.15

3.3.2 CO_2e EMISSION RATE ESTIMATES

The total CO_2e emission rate for each hot oil heater is estimated by multiplying the speciated emission rates in Table 3.3-1 by the appropriate GWP in Table 3.2-1. Table 3.3-2 summarizes the CO_2e emission rates for each hot oil heater at the Jefferson County NGL Fractionation Plant.

Table 3.3-2
GHG Emission Rates for All Hot Oil Heaters

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
HOH1	CO_2e	21,386.89	78,499.50
HOH2	CO_2e	21,386.89	78,499.50
Total	**CO_2e**	**42,773.78**	**156,999.00**

3.4 MOLECULAR SIEVE DEHYDRATOR REGENERATION HEATERS

The system used to dehydrate the inlet feed stock at the Jefferson County NGL Fractionation Plant will use one regeneration heater per train to regenerate the molecular sieve dehydrator beds. The regeneration heaters are fired using natural gas delivered via pipeline. Combustion of this fuel within the regeneration heaters results in emissions of GHG.

3.4.1 CO_2, CH_4, AND N_2O EMISSION RATE ESTIMATES

The CO_2, CH_4, and N_2O emission factors are from the MRR, as discussed in Section 3.1. The emission factor for each GHG is presented in Table 3.4-1.

The E_{MAX} of CO_2, CH_4, and N_2O from each regeneration heater is estimated as follows (using the maximum firing rate and CO_2 as an example):

$$E_{MAX}\left(\frac{\text{lb}}{\text{hr}}\right) = F \div HV \times HR$$

$$= \left(\frac{120{,}161 \text{ lb } CO_2}{\text{MMscf}}\right) \times \left(\frac{\text{scf}}{1{,}006.68 \text{ Btu}}\right) \times \left(\frac{36 \text{ MMBtu}}{\text{hr}}\right)$$

$$= 4{,}297.09 \ \frac{\text{lb}}{\text{hr}} \ CO_2$$

Where F = Emission Factor (lb CO_2/MMscf)
HV = Heating Value of Natural Gas (Btu/scf)
HR = Maximum Heater Firing Rate (MMBtu/hr)

The E_{ANN} of each compound from each regeneration heater is based on 6,000 operating hours per year at the maximum firing rate plus 2,760 operating hours per year in standby mode at the pilot firing rate. The emission rates are estimated as follows (using the maximum firing rate and CO_2 as an example):

$$E_{ANN}\ (\text{tpy}) = F \div HV \times HR \times \left(\frac{6{,}000 \text{ hrs}}{\text{yr}}\right) \times \left(\frac{1 \text{ ton}}{2{,}000 \text{ lbs}}\right)$$

$$= \left(\frac{120{,}161 \text{ lb } CO_2}{\text{MMscf}}\right) \times \left(\frac{\text{scf}}{1{,}006.68 \text{ Btu}}\right) \times \left(\frac{36 \text{ MMBtu}}{\text{hr}}\right) \times \left(\frac{6{,}000 \text{ hrs}}{\text{yr}}\right) \times \left(\frac{1 \text{ ton}}{2{,}000 \text{ lbs}}\right)$$

$$= 12{,}891.27 \text{ tpy } CO_2$$

Where F = Emission Factor (lb CO_2/MMscf)
HV = Heating Value of Natural Gas (Btu/scf)
HR = Maximum Heater Firing Rate (MMBtu/hr)

The emission rates in standby mode are estimated using the same methods shown above at the pilot firing rate. The emission rate of each GHG per regeneration heater is summarized in Table 3.4-1.

Table 3.4-1
Regeneration Heater GHG Emission Rates

Pollutant	Emission Factor (lb/MMscf)	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	120,161	4,297.09	12,958,76
CH_4	2.27	0.08	0.24
N_2O	0.23	0.008	0.02

3.4.2 CO_2e EMISSION RATE ESTIMATES

The total CO_2e emission rate for each regeneration heater is estimated by multiplying the speciated emission rates in Table 3.4-1 by the appropriate GWP in Table 3.2-1.

Table 3.4-2 summarizes the CO_2e emission rates for each regeneration heater at the Jefferson County NGL Fractionation Plant.

Table 3.4-2
GHG Emission Rates for All Regeneration Heaters

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
HTR1	CO_2e	4,301.25	12,970.05
HTR2	CO_2e	4,301.25	12,970.05
Total	**CO_2e**	**8,602.5**	**25,940.10**

3.5 PROCESS FLARE ROUTINE EMISSIONS

During routine operations, the flare is used to combust intermittent waste gases from analyzer sample purges and pump seal leaks. No flow is normally expected to the process waste water flash drum; therefore, no waste gases are expected from this potential source during routine operations. These routine emission sources are routed to the flare rather than the TO, because they are not expected to be stable in quantity and flow rate which would allow them to be properly controlled by the TO. Emission estimates for these waste gas streams are based on worst-case assumptions for the hourly flow rate of waste gas from sample purges and the hourly leak rate of pump seals. Although these maximum hourly emission rates do not occur on a continuous basis, annual emissions for these waste gases are conservatively estimated assuming the maximum hourly emission rate occurs 8,760 hours per year. Emission estimates for these waste gases are provided in Section 6.0, Attachment B. The flare also combusts a small amount of pilot gas used to maintain flame presence and sweep gas used to maintain flare header pressure.

The flare is also used to control waste gases from MSS activities. The MSS emissions are discussed in detail in Section 3.10.

3.5.1 NATURAL GAS FUEL COMBUSTION EMISSIONS

The flare combusts 280 standard cubic feet per hour (“scf/hr”) of pilot gas and 3,066 scf/hr of sweep gas. The CO_2 emission factor is based on the MRR, as discussed in Section 3.1. The emission factor for each GHG is presented in Table 3.5-1.

The E_{MAX} of CO_2, CH_4, and N_2O from the flare due to the combustion of pilot gas and sweep gas are estimated as follows (using CO_2 as an example):

$$\begin{aligned} E_{MAX}\left(\frac{\text{lb}}{\text{hr}}\right) &= Q \times EF \times \left(\frac{1\ \text{MMscf}}{10^6\ \text{scf}}\right) \\ &= \left(\frac{3{,}346\ \text{scf}}{\text{hr}}\right) \times \left(\frac{120{,}161\ \text{lb CO}_2}{\text{MMscf}}\right) \times \left(\frac{1\ \text{MMscf}}{10^6\ \text{scf}}\right) \\ &= 402.06\ \frac{\text{lb}}{\text{hr}}\text{CO}_2 \end{aligned}$$

Where Q = Volumetric Fuel Flow Rate (scf/hr)
EF = CO_2 Emission Factor

The E_{ANN} of CO_2, CH_4, and N_2O from combustion of the pilot and sweep gas is estimated as follows (using CO_2 as an example):

$$\begin{aligned}E_{ANN}\ (\text{tpy}) &= Q \times EF \times \left(\frac{1\ \text{MMscf}}{10^6\ \text{scf}}\right) \times \left(\frac{8{,}760\ \text{hr}}{\text{yr}}\right) \times \left(\frac{1\ \text{ton}}{2{,}000\ \text{lbs}}\right)\\ &= \left(\frac{3{,}346\ \text{scf}}{\text{hr}}\right) \times \left(\frac{120{,}161\ \text{lb}\ CO_2}{\text{MMscf}}\right) \times \left(\frac{1\ \text{MMscf}}{10^6\ \text{scf}}\right) \times \left(\frac{8{,}760\ \text{hr}}{\text{yr}}\right) \times \left(\frac{1\ \text{ton}}{2{,}000\ \text{lbs}}\right)\\ &= 1{,}761.02\ \text{tpy}\ CO_2\end{aligned}$$

Where Q = Volumetric Fuel Flow Rate (scf/hr)
EF = CO_2 Emission Factor

Table 3.5-1 summarizes the GHG emission rates for the flare from fuel gas combustion.

Table 3.5-1
Flare GHG Emission Rates for Fuel Gas Combustion

Pollutant	Emission Factor (lb/MMscf)	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	120,161	402.06	1,761.02
CH_4	2.27	8.0E-03	0.03
N_2O	0.23	8.0E-04	3.4E-03

The total CO_2e emission rate for the flare from burning fuel gas is estimated by multiplying the speciated emission rates in Table 3.5-1 by the appropriate GWP in Table 3.2-1. Table 3.5-2 summarizes the CO_2e emission rates for the flare from burning fuel gas.

Table 3.5-2
Flare GHG Emission Rates from Fuel Gas

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
FLR1	CO_2e	402.48	1,762.76

3.5.2 WASTE GAS COMBUSTION EMISSIONS

COMBUSTION OF CARBON CONTAINING COMPOUNDS IN INTERMITTENT WASTE GASES – CO_2 EMISSION RATE

The majority of the CO_2 emitted from the flare due to combustion of the intermittent waste gas streams is the result of conversion of carbon containing compounds into CO_2 during combustion. However, the sample purge stream that is routed to the flare also contains a minor amount of CO_2 that passes through the flare unchanged, along with the CO_2 created from combustion of carbon containing compounds in the flare. The “pass-through” CO_2 emissions are added to the total combustion related CO_2 to estimate the total CO_2 emissions

The E_{MAX} of CO_2 from combustion of carbon containing compounds in the intermittent waste gas streams is estimated assuming all carbon in the compound is converted into CO_2 as follows (using n-hexane from the Feed to Deethanizer Analyzer sample purge stream as an example):

$$
\begin{aligned}
E_{MAX}\left(\frac{\text{lb}}{\text{hr}}\right) &= M \times MW_{C6} \times S \times MW_{CO2} \\
&= \left(\frac{0.06\ \text{lb n-C}_6}{\text{hr}}\right) \times \left(\frac{\text{lb-mol n-C}_6}{86.10\ \text{lb n-C}_6}\right) \times \left(\frac{6\ \text{lb-mol CO}_2}{\text{lb-mol n-C}_6}\right) \times \left(\frac{44.01\ \text{lb CO}_2}{\text{lb-mol CO}_2}\right) \\
&= 0.18\ \frac{\text{lb}}{\text{hr}}\text{CO}_2
\end{aligned}
$$

Where M = Mass Flow Rate of n-Hexane to the Flare (lb/hr)
MW_{C6} = Molecular Weight of n-Hexane
S = Number of CO_2 molecules generated per molecules of n-Hexane
MW_{CO2} = Molecular Weight of CO_2

The E_{MAX} of CO_2 from combustion of all carbon containing compounds in the intermittent waste gas streams, calculated as shown above for each compound in the waste gas, plus the small amount of CO_2 already in the streams is 46.65 lb/hr.

The E_{ANN} of CO_2 from combustion of carbon containing compounds in the intermittent waste gas streams is estimated assuming all carbon in the compound is converted into CO_2 as follows (using n-hexane from the Feed to Deethanizer Analyzer sample purge stream as an example):

$$\begin{aligned}
E_{ANN}\ (\text{tpy}) &= M \times MW_{C6} \times S \times MW_{CO2} \times \left(\frac{8{,}760\ \text{hrs}}{\text{yr}}\right) \times \left(\frac{1\ \text{ton}}{2{,}000\ \text{lb}}\right) \\
&= \left(\frac{0.06\ \text{lb n-}C_6}{\text{hr}}\right) \times \left(\frac{\text{lb-mol n-}C_6}{86.10\ \text{lb n-}C_6}\right) \times \left(\frac{6\ \text{lb-mol } CO_2}{\text{lb-mol n-}C_6}\right) \times \\
&\quad \left(\frac{44.01\ \text{lb } CO_2}{\text{lb-mol } CO_2}\right) \times \left(\frac{8{,}760\ \text{hrs}}{\text{yr}}\right) \times \left(\frac{1\ \text{ton}}{2{,}000\ \text{lb}}\right) \\
&= 0.81\ \text{tpy } CO_2
\end{aligned}$$

Where M = Mass Flow Rate of n-Hexane to the Flare (lb / hr)
MW_{C6} = Molecular Weight of n-Hexane
S = Number of CO_2 molecules generated per molecule of n-Hexane
MW_{CO2} = Molecular Weight of CO_2

The E_{ANN} of CO_2 from combustion of carbon containing compounds in the intermittent waste gas streams, calculated as shown above for each compound in the waste gas, plus the small amount of CO_2 already in the streams is 204.49 tpy.

COMBUSTION OF INTERMITTENT WASTE GAS – CH_4 EMISSION RATE

The flare has a DRE of 98%. The E_{MAX} of CH_4 from uncombusted CH_4 in the intermittent waste gas streams is estimated as follows (using CH_4 from the Feed to Deethanizer Analyzer sample purge stream as an example):

$$\begin{aligned}
E_{MAX}\left(\frac{\text{lb}}{\text{hr}}\right) &= ER \times (100\% - DRE\%) \\
&= \left(0.008\ \frac{\text{lb } CH_4}{\text{hr}}\right) \times (100\% - 98\%) \\
&= 0.00016\ \frac{\text{lb}}{\text{hr}} CH_4
\end{aligned}$$

Where ER = Methane Emission Rate in Waste Gas (lb/hr)
DRE = Flare Destruction Efficiency

The total uncombusted CH_4 in all waste gas streams is 0.001 lb/hr.

The maximum E_{ANN} of CH_4 from uncombusted CH_4 in the waste gas streams is estimated as follows (using CH_4 from the Feed to Deethanizer Analyzer sample purge stream as an example):

$$E_{ANN}\ (tpy) = ER \times (100\% - DRE\%) \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lb}\right)$$

$$= \left(0.008\ \frac{lb\ CH_4}{hr}\right) \times (100\% - 98\%) \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton\ CH_4}{2{,}000\ lb\ CH_4}\right)$$

$$= 6.9 \times 10^{-5}\ tpy\ CH_4$$

Where ER = Methane Emission Rate in Waste Gas (lb/hr)
DRE = Flare Destruction Efficiency

The total uncombusted CH_4 in all waste gas streams is 0.003 tpy.

COMBUSTION OF INTERMITTENT WASTE GAS – N_2O EMISSION RATE

The N_2O emission rate from the flare due to combustion of intermittent waste gas streams is estimated using Equation W-40, 40 CFR Part 98, Subpart W. Equation W-40 uses a waste gas heating value of 1.235×10^{-3} MMBtu/scf, an emission factor of 1×10^{-4} kg N_2O/MMBtu, and the total molar flow rate of waste gas sent to the flare. The molar flow rate for compounds in the various analyzer sample purge streams was provided by the engineering company; therefore, the example used to show the method for estimating the molar flow rate is for pump seal leaks.

The maximum hourly molar flow rate of intermittent waste gas is estimated as follows (using propane from the propane injection pump seal leak as an example):

$$\text{Mo}\left(\frac{\text{lb-mol}}{\text{hr}}\right) = \text{M} \div \text{MW}$$

$$= \left(\frac{0.11464 \text{ lb propane}}{\text{hr}}\right) \times \left(\frac{1 \text{ lb-mol propane}}{44.10 \text{ lb propane}}\right)$$

$$= 0.0026 \ \frac{\text{lb-mol propane}}{\text{hr}}$$

Where Mo = Molar Flow Rate of propane (lb-mol/hr)
M = Mass emission rate of propane
MW = Molecular Weight of propane

The total maximum hourly molar flow rate of intermittent waste gas, calculated as shown above for each compound in the waste gas, is 0.32 lb-mol/hr.

The total maximum hourly N_2O emission rate due to combustion of all compounds in intermittent waste gas is estimated as follows:

$$E_{MAX}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Mo} \times \text{EF} \times \text{HV} \times \text{V}$$

$$= \left(\frac{0.32 \text{ lb-mol}}{\text{hr}}\right) \times \left(\frac{0.0002 \text{ lb } N_2O}{\text{MMBtu}}\right) \times \left(\frac{0.001235 \text{ MMBtu}}{\text{scf}}\right) \times \left(\frac{379.5 \text{ scf}}{\text{lb-mol}}\right)$$

$$= 3.0 \text{ x } 10^{-5} \ \frac{\text{lb}}{\text{hr}} N_2O$$

Where Mo = Molar Flow Rate (lb-mol/hr)
EF = N_2O Emission Factor
HV = Heating Value of Waste Gas (MMBtu/scf)
V = Standard Molar Volume of Gas (scf/lb-mol)

The total annual N_2O emission rate due to combustion of all compounds in intermittent waste gas is estimated as follows:

$$
\begin{aligned}
E_{ANN}\ (tpy) &= Mo \times EF \times HV \times V \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lbs}\right) \\
&= \left(\frac{0.32\ lb\text{-}mol}{hr}\right) \times \left(\frac{0.0002\ lb\ N_2O}{MMBtu}\right) \times \left(\frac{0.001235\ MMBtu}{scf}\right) \times \\
&\quad \left(\frac{379.5\ scf}{lb\text{-}mol}\right) \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton\ N_2O}{2{,}000\ lbs\ N_2O}\right) \\
&= 1.3 \times 10^{-4}\ tpy\ N_2O
\end{aligned}
$$

Where Mo = Molar Flow Rate (lb-mol/hr)
EF = N_2O Emission Factor
HV = Heating Value of Waste Gas (MMBtu/scf)
V = Standard Molar Volume of Gas (scf/lb-mol)

Table 3.5-3 summarizes the GHG emission rates for the flare from intermittent waste gas combustion.

Table 3.5-3
Flare GHG Emission Rates for Intermittent Waste Gas Combustion

Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	46.65	204.49
CH_4	1.0E-03	3.0E-03
N_2O	3.0E-05	1.3E-04

The total CO_2e emission rate for the flare from burning intermittent waste gas is estimated by multiplying the speciated emission rates in Table 3.5-3 by the appropriate GWP in Table 3.2-1. Table 3.5-4 summarizes CO_2e emission rate for the flare from burning intermittent waste gas.

Table 3.5-4
Flare GHG Emission Rates for Intermittent Waste Gas Combustion

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
FLR1	CO_2e	46.68	204.59

Table 3.5-5 summarizes the total CO_2e emission rate for the flare from combusting both fuel gas and intermittent waste gas.

Table 3.5-5
Flare GHG Emission Rates

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
FLR1 – Fuel Gas	CO_2e	402.48	1,762.76
FLR1 – Waste Gas	CO_2e	46.68	204.59
Total	**CO_2e**	**449.16**	**1,967.35**

3.6 THERMAL OXIDIZERS

The TOs are used to control emissions from the amine unit rich amine flash drum and regeneration vents, natural gasoline treater flash pot vent, and compressor seal gas vents from each train. Normal operation TO emissions consist of the combustion of natural gas fuel and combustion of waste gas from the vents being controlled by the TO.

3.6.1 NATURAL GAS FUEL COMBUSTION EMISSIONS

The TO uses a burner fueled by natural gas to maintain a flame within the firebox to properly combust waste gases it is used to control. Combustion of the fuel gas results in GHG emissions. The factors used to estimate emissions of CO_2, CH_4, and N_2O are from the MRR, as discussed in Section 3.1. The emission factor for each GHG is presented in Table 3.6-1.

The TO fuel gas heat input is 5 MMBtu/hr. The E_{MAX} of CO_2, CH_4, and N_2O from combustion of natural gas are estimated as follows (using CO_2 as an example):

$$E_{MAX}\left(\frac{lb}{hr}\right) = F \div HV \times HR$$

$$= \left(\frac{120{,}161\ lb\ CO_2}{MMscf}\right) \times \left(\frac{scf}{1{,}006.68\ Btu}\right) \times \left(\frac{5\ MMBtu}{hr}\right)$$

$$= 596.82\ \frac{lb}{hr}\ CO_2$$

Where F = Emission Factor (lb CO_2/MMscf)
HV = Heating Value of Natural Gas (Btu/scf)
HR = Maximum TO Burner Firing Rate (MMBtu/hr)

The E_{ANN} from each TO is based on 8,760 hours per year operation. The E_{ANN} of CO_2, CH_4, and N_2O from combustion of natural gas are estimated as follows (using CO_2 as an example):

$$E_{ANN}\ (tpy) = F \div HV \times HR \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lbs}\right)$$

$$= \left(\frac{120{,}161\ lb\ CO_2}{MMscf}\right) \times \left(\frac{scf}{1006.68\ Btu}\right) \times \left(\frac{5\ MMBtu}{hr}\right) \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lbs}\right)$$

$$= 2{,}614.06\ tpy\ CO_2$$

Where F = Emission Factor (lb CO_2/MMscf)
HV = Heating Value of Natural Gas (Btu/scf)
HR = Maximum TO Burner Firing Rate (MMBtu/hr)

Table 3.6-1 summarizes the GHG emission rates for each TO from fuel gas combustion.

Table 3.6-1
TO GHG Emission Rates from Fuel Gas Combustion

Pollutant	Emission Factor (lb/MMscf)	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	120,161	596.82	2,614.06
CH_4	2.27	0.01	0.05
N_2O	0.23	0.001	0.005

The total CO_2e emission rate for each TO from burning fuel gas is estimated by multiplying the speciated emission rates in Table 3.6-1 by the appropriate GWP in Table 3.2-1. Table 3.6-2 summarizes the CO_2e emission rates for the TOs from burning fuel gas.

Table 3.6-2
TO GHG Emission Rates for Fuel Gas Combustion

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
TO1	CO_2e	597.34	2,616.65
TO2	CO_2e	597.34	2,616.65
Total	**CO_2e**	**1,194.68**	**5,233.30**

3.6.2 WASTE GAS COMBUSTION EMISSIONS

Emissions of GHGs from waste gas streams routed to the TO are the result of combustion of carbon compounds in the waste gas stream, the portion of CH_4 in the waste gas stream that is not destroyed, and CO_2 in the waste gas stream that passes through the TO unchanged. The composition of the waste gas streams routed to the TO was provided by the company engineering the plant, using process modeling software. Information on waste gas stream compositions is provided in the detailed emission estimates in Section 6.0, Attachment B.

COMBUSTION OF CARBON CONTAINING COMPOUNDS IN WASTE GAS - CO_2 EMISSION RATE

The E_{MAX} of CO_2 from combustion of carbon containing compounds in the waste gas streams is estimated as follows (using n-hexane from the combined amine unit vents as an example):

$$E_{MAX}\left(\frac{\text{lb}}{\text{hr}}\right) = M \times MW_{C6} \times S \times MW_{CO2}$$

$$= \left(\frac{0.05\text{ lb n-C}_6}{\text{hr}}\right) \times \left(\frac{\text{lb-mol n-C}_6}{86.10\text{ lb n-C}_6}\right) \times \left(\frac{6\text{ lb-mol CO}_2}{\text{lb-mol n-C}_6}\right) \times \left(\frac{44.01\text{ lb CO}_2}{\text{lb-mol CO}_2}\right)$$

$$= 0.15\ \frac{\text{lb}}{\text{hr}}\text{CO}_2$$

Where M = Mass Flow Rate of n-Hexane to the Thermal Oxidizer (lb/hr)
MW_{C6} = Molecular Weight of n-Hexane
S = Number of CO_2 molecules generated per molecule of n-Hexane
MW_{CO2} = Molecular Weight of CO_2

The maximum hourly emission rate of CO_2 from combustion of all carbon containing compounds in the waste gas streams is 481.92 lb/hr.

The E_{ANN} of CO_2 from combustion of all carbon containing compounds in the waste gas streams is estimated as follows (using n-hexane from the combined amine unit vents as an example):

$$
\begin{aligned}
E_{ANN}\ (\text{tpy}) &= M \times MW_{C6} \times S \times MW_{CO2} \times \left(\frac{8{,}760\ \text{hrs}}{\text{yr}}\right) \times \left(\frac{1\ \text{ton}}{2{,}000\ \text{lb}}\right) \\
&= \left(\frac{0.05\ \text{lb n-}C_6}{\text{hr}}\right) \times \left(\frac{\text{lb-mol n-}C_6}{86.10\ \text{lb n-}C_6}\right) \times \left(\frac{6\ \text{lb-mol } CO_2}{\text{lb-mol n-}C_6}\right) \times \left(\frac{44.01\ \text{lb } CO_2}{\text{lb-mol } CO_2}\right) \times \left(\frac{8{,}760\ \text{hrs}}{\text{yr}}\right) \times \left(\frac{1\ \text{ton}}{2{,}000\ \text{lb}}\right) \\
&= 0.67\ \text{tpy } CO_2
\end{aligned}
$$

Where M = Mass Flow Rate of n-Hexane to the Thermal Oxidizer (lb/hr)
MW_{C6} = Molecular Weight of n-Hexane
S = Number of CO_2 molecules generated per molecule of n-Hexane
MW_{CO2} = Molecular Weight of CO_2

The E_{ANN} of CO_2 from combustion of carbon containing compounds in the waste gas streams is 2,109.07 tpy.

CO_2 IN WASTE GAS

The total CO_2 in the waste gas streams that passes through the TO unchanged is 935.36 lb/hr and 4,096.86 tpy. These numbers were provided by the company engineering the plant and do not require additional calculations. See detailed emission estimates in Section 6.0, Attachment B.

COMBUSTION OF WASTE GAS – CH_4 EMISSION RATE

The TOs have a DRE of 99.9%. The E_{MAX} of CH_4 from uncombusted CH_4 in the waste gas streams is estimated as follows (using CH_4 from the combined amine unit vents as an example):

$$
\begin{aligned}
E_{MAX}\left(\frac{\text{lb}}{\text{hr}}\right) &= ER \times (100\% - DRE\%) \\
&= \left(4.63\ \frac{\text{lb } CH_4}{\text{hr}}\right) \times (100\% - 99.9\%) \\
&= 0.005\ \frac{\text{lb}}{\text{hr}} CH_4
\end{aligned}
$$

Where ER = Methane Emission Rate in Waste Gas (lb/hr)
DRE = TO Destruction Efficiency

The total uncombusted CH_4 in all waste gas streams is 0.005 lb/hr.

The maximum E_{ANN} of CH_4 from uncombusted CH_4 in the waste gas streams is estimated as follows (using CH_4 from the combined amine unit vents as an example):

$$
\begin{aligned}
E_{ANN}\ (\text{tpy}) &= ER \times (100\% - DRE\%) \times \left(\frac{8{,}760\ \text{hrs}}{\text{yr}}\right) \times \left(\frac{1\ \text{ton}}{2{,}000\ \text{lb}}\right) \\
&= \left(4.63\ \frac{\text{lb } CH_4}{\text{hr}}\right) \times (100\% - 99.9\%) \times \left(\frac{8{,}760\ \text{hrs}}{\text{yr}}\right) \times \left(\frac{1\ \text{ton } CH_4}{2{,}000\ \text{lb } CH_4}\right) \\
&= 0.02\ \text{tpy } CH_4
\end{aligned}
$$

Where ER = Methane Emission Rate in Waste Gas (lb/hr)
DRE = TO Destruction Efficiency

The total uncombusted CH_4 in all waste gas streams is 0.02 tpy.

COMBUSTION OF WASTE GAS – N_2O EMISSION RATE

The N_2O emission rate from the TO due to combustion of waste gas is calculated using Equation W-40, 40 CFR Part 98, Subpart W. Equation W-40 uses a waste gas heating value of 1.235×10^{-3} MMBtu/scf and an emission factor of 1×10^{-4} kg N_2O/MMBtu.

The maximum hourly molar flow rate of waste gas is estimated as follows (using n-hexane from the combined amine unit vents as an example):

$$
\begin{aligned}
Mo \left(\frac{\text{lb-mol}}{\text{hr}}\right) &= M \div MW \\
&= \left(\frac{4.63\ \text{lb n-}C_6}{\text{hr}}\right) \times \left(\frac{1\ \text{lb-mol n-}C_6}{86.10\ \text{lb n-}C_6}\right) \\
&= 0.05\ \frac{\text{lb-mol n-}C_6}{\text{hr}}
\end{aligned}
$$

Where Mo = Molar Flow Rate of n-Hexane (lb-mol/hr)
M = Mass Emission Rate of n-Hexane
MW = Molecular Weight of n-Hexane

The total maximum hourly molar flow rate of waste gas from all sources combined is 5.05 lb-mol/hr.

The total maximum hourly N_2O emission rate due to combustion of all compounds in waste gas is estimated as follows:

$$E_{MAX}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Mo} \times \text{EF} \div \text{HV} \times \text{V}$$
$$= \left(\frac{5.05 \text{ lb-mol}}{\text{hr}}\right) \times \left(\frac{0.0002 \text{ lb } N_2O}{\text{MMBtu}}\right) \times \left(\frac{0.001235 \text{ MMBtu}}{\text{scf}}\right) \times \left(\frac{379.5 \text{ scf}}{\text{lb-mol}}\right)$$
$$= 4.7 \text{ x } 10^{-4} \ \frac{\text{lb } N_2O}{\text{hr}}$$

Where Mo = Molar Flow Rate (lb-mol/hr)
EF = N_2O Emission Factor
HV = Heating Value of Waste Gas (MMBtu/scf)
V = Standard Molar Volume of Gas (scf/lb-mol)

The total annual N_2O emission rate due to combustion of all compounds in waste gas is estimated as follows:

$$E_{ANN}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Mo} \times \text{EF} \div \text{HV} \times \text{V} \times \left(\frac{8{,}760 \text{ hrs}}{\text{yr}}\right) \times \left(\frac{1 \text{ ton}}{2{,}000 \text{ lbs}}\right)$$
$$= \left(\frac{5.05 \text{ lb-mol}}{\text{hr}}\right) \times \left(\frac{0.0002 \text{ lb } N_2O}{\text{MMBtu}}\right) \times \left(\frac{0.001235 \text{ MMBtu}}{\text{scf}}\right) \times$$
$$\left(\frac{379.5 \text{ scf}}{\text{lb-mol}}\right) \times \left(\frac{8{,}760 \text{ hrs}}{\text{yr}}\right) \times \left(\frac{1 \text{ ton } N_2O}{2{,}000 \text{ lbs } N_2O}\right)$$
$$= 2.1 \text{ x } 10^{-3} \ \text{tpy } N_2O$$

Where Mo = Molar Flow Rate (lb-mol/hr)
EF = N_2O Emission Factor
HV = Heating Value of Waste Gas (MMBtu/scf)
V = Standard Molar Volume of Gas (scf/lb-mol)

Table 3.6-3 summarizes the GHG emission rates for each TO from waste gas combustion.

Table 3.6-3
TO GHG Emission Rates for Waste Gas Combustion

Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	1,417.28	6,205.93
CH_4	5.0E-03	0.02
N_2O	4.7E-04	2.1E-03

The total CO_2e emission rate for each TO from combusting waste gas is estimated by multiplying the speciated emission rates in Table 3.6-3 by the appropriate GWP in Table 3.2-1. Table 3.6-4 summarizes the speciated GHG and CO_2e emission rates for the TOs from combusting waste gas.

Table 3.6-4
TO GHG Emission Rates for Waste Gas Combustion

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
TO1	CO_2e	1,417.53	6,207.02
TO2	CO_2e	1,417.53	6,207.02
Total	**CO_2e**	**2,835.06**	**12,414.04**

Table 3.6-5 summarizes the total CO_2e emission rate for the TOs from combusting both fuel gas and waste gas.

Table 3.6-5
TO GHG Emission Rates

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
TO1 – Fuel Gas	*CO_2e*	*597.34*	*2,616.65*
TO1 – Waste Gas	*CO_2e*	*1,417.53*	*6,207.02*
TO1 - Total	CO_2e	2,014.87	8,823.67
TO2 - Total	CO_2e	2,014.87	8,823.67
Total	**CO_2e**	**4,029.74**	**17,647.34**

3.7 FIREWATER PUMP AND EMERGENCY GENERATOR ENGINES

3.7.1 CO_2, CH_4, N_2O EMISSION RATE ESTIMATES

The CO_2, CH_4, and N_2O emission factors are from the MRR, as discussed in Section 3.1, for Distillate Fuel Oil No. 2. The emission factors are converted from kg/MMBtu to lb/MMBtu as follows (using CO_2 as an example):

$$\left(\frac{73.96 \text{ kg CO}_2}{\text{MMBtu}}\right) \times \left(\frac{2.2046 \text{ lb CO}_2}{\text{kg CO}_2}\right) = 163.05 \ \frac{\text{lb CO}_2}{\text{MMBtu}}$$

The fuel consumption of each engine is estimated using AP-42 Table 3-3.1, Footnote A for diesel fired engines. The heat input rate of each engine is estimated as follows:

$$\begin{aligned} HR\left(\frac{\text{MMBtu}}{\text{hr}}\right) &= HP \times FC \times \left(\frac{1\ \text{MMBtu}}{10^6\ \text{Btu}}\right) \\ &= (500\ \text{hp}) \times \left(\frac{7{,}000\ \text{Btu}}{\text{hp}-\text{hr}}\right) \times \left(\frac{1\ \text{MMBtu}}{10^6\ \text{Btu}}\right) \\ &= 3.5\ \frac{\text{MMBtu}}{\text{hr}} \end{aligned}$$

Where HP = Engine Horsepower Rating
FC = Engine Estimated Fuel Consumption

The E_{MAX} for each engine are estimated as follows (using CO_2 as an example):

$$\begin{aligned} E_{MAX}\left(\frac{\text{lb}}{\text{hr}}\right) &= HR \times EF \\ &= \left(\frac{3.5\ \text{MMBtu}}{\text{hr}}\right) \times \left(\frac{163.05\ \text{lb}\ CO_2}{\text{MMBtu}}\right) \\ &= 570.68\frac{\text{lb}\ CO_2}{\text{hr}} \end{aligned}$$

Where HR = Maximum Hourly Heat Rate
EF = CO_2 Emission Factor

The E_{ANN} for each engine are estimated as follows, based on the non-emergency operating hour limit of 100 hours per year (using CO_2 as an example):

$$\begin{aligned} E_{ANN}\ (\text{tpy}) &= HR \times EF \times \left(\frac{100\ \text{hrs}}{\text{yr}}\right) \times \left(\frac{1\ \text{ton}}{2{,}000\ \text{lb}}\right) \\ &= \left(\frac{3.5\ \text{MMBtu}}{\text{hr}}\right) \times \left(\frac{163.05\ \text{lb}\ CO_2}{\text{MMBtu}}\right) \times \left(\frac{100\ \text{hrs}}{\text{yr}}\right) \times \left(\frac{1\ \text{ton}}{2{,}000\ \text{lb}}\right) \\ &= 28.53\ \text{tpy}\ CO_2 \end{aligned}$$

Where HR = Maximum Hourly Heat Rate
EF = CO_2 Emission Factor

Table 3.7-1 summarizes the GHG emission rates for the each engine.

Table 3.7-1
Firewater Pump and Emergency Generator Engines
GHG Emission Rates

Pollutant	Emission Factor (lb/MMBtu)	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	163.05	570.68	28.53
CH_4	0.007	0.02	0.001
N_2O	0.001	0.004	0.0002

3.7.2 CO_2e EMISSION RATE ESTIMATE

The total CO_2e emission rate for the each engine is estimated by multiplying the speciated emission rates in Table 3.7-1 by the appropriate GWP in Table 3.2-1. Table 3.7-2 summarizes the CO_{2e} emission rates for the both engines.

Table 3.7-2
Firewater Pump and Emergency Generator Engines
GHG Emission Rates

EPN	Description	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
ENG1	Firewater Pump Engine	CO_2e	572.34	28.62
ENG2	Emergency Generator Engine	CO_2e	572.34	28.62
Total		**CO_2e**	**1,144.68**	**57.24**

3.8 EQUIPMENT COMPONENT FUGITIVE EMISSION RATES

Some equipment components within the Jefferson County NGL Fractionation Plant are potential sources of CO_2 and CH_4 emissions due to leaking valves, flanges, seals, etc. For example, the acid gas stream includes approximately 90.55% (by weight) CO_2 (see Section 6.0, Attachment B). Therefore, in the event of any equipment component leaks, a small amount of GHGs could be emitted to the atmosphere.

Potential GHG emissions from leaking equipment components are estimated using emission factors in the TCEQ's technical guidance for "Equipment Leak Fugitives" (October 2000) for Oil and Gas Facilities. DCP will implement a 28LAER monitoring program to control the emissions from equipment leak fugitives.

The maximum hourly CO_2 emissions, using gas valves in acid gas service as an example, are estimated as follows:

$$
\begin{aligned}
E_{MAX}\left(\frac{\text{lb}}{\text{hr}}\right) &= N \times EF \times (100\% - \%R) \times \%CO_2 \\
&= (43) \times \left(\frac{0.00992\ \text{lb}}{\text{hr-component}}\right) \times (100\% - 97\%) \times (90.55\%) \\
&= 0.012\ \frac{\text{lb } CO_2}{\text{hr}}
\end{aligned}
$$

Where N = Number of Components
EF = Equipment Leak Emission Factor
%R = Monitoring Program Control Efficiency
$\%CO_2$ = Weight Percent CO_2 in Emission Stream

Annual emissions of CO_2 from gas valves in acid gas service are estimated as follows:

$$
\begin{aligned}
E_{ANN}\ (\text{tpy}) &= N \times EF \times (100\% - \%R) \times \%CO_2 \times \left(\frac{8{,}760\text{ hrs}}{\text{yr}}\right) \times \left(\frac{1\text{ ton}}{2{,}000\text{ lb}}\right)\\
&= (43) \times \left(\frac{0.00992\text{ lb}}{\text{hr-component}}\right) \times (100\% - 97\%) \times (90.55\%) \times \left(\frac{8{,}760\text{ hrs}}{\text{yr}}\right) \times \left(\frac{1\text{ ton}}{2{,}000\text{ lb}}\right)\\
&= 0.05\text{ tpy } CO_2
\end{aligned}
$$

Where N = Number of Components
EF = Equipment Leak Emission Factor
$\%R$ = Monitoring Program Control Efficiency
$\%CO_2$ = Weight Percent CO_2 in Emission Stream

Total maximum CO_2 and CH_4 emissions for all components in all streams are calculated using the method described above and are equal to 0.04 lb/hr and 0.17 tpy CO_2, and 0.22 lb/hr and 0.96 tpy CH_4.

The total CO_2e emission rate for the equipment leak fugitives is estimated by multiplying the speciated emission rates in by the appropriate GWP in 3.2-1, and is estimated to be 67.84 lb/hr and 297.15 tpy, per train.

3.9 TRACE ERASE SYSTEM

The trace erase (“TE”) system is used to convert hydrocarbon emissions in a small fraction of the sample purge gas from various process analyzers used throughout the process into CO_2 and water before emitting these streams to the atmosphere. This small fraction of sample purge gas from the analyzers is routed to the TE system rather than the flare because routing the stream to this control device would create backpressure resulting in inaccurate operation of the process analyzers. The proposed facility has one TE system for each process train. The TE system operates using an electrical heating element to combust the hydrocarbons, generating CO_2 and water.

3.9.1 ANALYZER SAMPLE PURGE GAS COMBUSTION EMISSIONS

Emissions of GHGs from the analyzer sample purge gas streams routed to the TE system are the result of combustion of carbon compounds in the sample purge gas, the portion of CH_4 in the sample purge gas that is not destroyed, and CO_2 in the sample purge gas that passes through the TE system unchanged. The composition of the sample purge gas routed to the TE system was provided by the company engineering the plant. The compositions for the sample purge gas routed to the TE system were generated using a combination of process modeling software and engineering knowledge. Although the analyzer sample purge gas is not expected to be continuous, it is assumed to be continuous to provide a conservative estimate of emissions. Information on sample purge gas compositions is provided in the detailed emission estimates in Section 6.0, Attachment B.

COMBUSTION OF CARBON CONTAINING COMPOUNDS IN ANALYZER SAMPLE PURGE GAS - CO_2 EMISSION RATE

The E_{MAX} of CO_2 from combustion of carbon containing compounds in each analyzer sample purge gas stream is estimated as follows (using n-hexane from the Feed to Deethanizer Analyzer sample purge gas stream as an example):

$$
\begin{aligned}
E_{MAX}\left(\frac{\text{lb}}{\text{hr}}\right) &= M \times MW_{C6} \times S \times MW_{CO2} \\
&= \left(\frac{0.00033\ \text{lb n-C}_6}{\text{hr}}\right) \times \left(\frac{\text{lb-mol n-C}_6}{86.10\ \text{lb n-C}_6}\right) \times \left(\frac{6\ \text{lb-mol CO}_2}{\text{lb-mol n-C}_6}\right) \times \left(\frac{44.01\ \text{lb CO}_2}{\text{lb-mol CO}_2}\right) \\
&= 0.001\ \frac{\text{lb}}{\text{hr}}\text{CO}_2
\end{aligned}
$$

Where M = Mass Flow Rate of n-Hexane to the Trace Erase System (lb/hr)
MW_{C6} = Molecular Weight of n-Hexane
S = Number of CO_2 molecules generated per molecule of n-Hexane
MW_{CO2} = Molecular Weight of CO_2

The maximum hourly emission rate of CO_2 from combustion of all carbon containing compounds in the analyzer sample purge gas streams is 0.25 lb/hr.

The E_{ANN} of CO_2 from combustion of all carbon containing compounds in each analyzer sample purge gas stream is estimated as follows (using n-hexane from the Feed to Deethanizer Analyzer sample purge gas stream as an example):

$$\begin{aligned} E_{ANN}\ (\text{tpy}) &= M \times MW_{C6} \times S \times MW_{CO2} \times \left(\frac{8{,}760\ \text{hrs}}{\text{yr}}\right) \times \left(\frac{1\ \text{ton}}{2{,}000\ \text{lb}}\right) \\ &= \left(\frac{0.00033\ \text{lb n-}C_6}{\text{hr}}\right) \times \left(\frac{\text{lb-mol n-}C_6}{86.10\ \text{lb n-}C_6}\right) \times \left(\frac{6\ \text{lb-mol }CO_2}{\text{lb-mol n-}C_6}\right) \times \left(\frac{44.01\ \text{lb }CO_2}{\text{lb-mol }CO_2}\right) \times \left(\frac{8{,}760\ \text{hrs}}{\text{yr}}\right) \times \left(\frac{1\ \text{ton}}{2{,}000\ \text{lb}}\right) \\ &= 0.004\ \text{tpy }CO_2 \end{aligned}$$

Where M = Mass Flow Rate of n-Hexane to the Trace Erase System (lb/hr)
MW_{C6} = Molecular Weight of n-Hexane
S = Number of CO_2 molecules generated per molecule of n-Hexane
MW_{CO2} = Molecular Weight of CO_2

The E_{ANN} of CO_2 from combustion of all carbon containing compounds in the analyzer sample purge gas streams is 1.10 tpy.

CO_2 IN ANALYZER SAMPLE PURGE GAS

The total CO_2 in the all analyzer sample purge gas streams combined that passes through the TE unchanged is 0.00002 lb/hr and 0.0001 tpy. These numbers were provided by the company engineering the plant and do not require additional calculations. See detailed emission estimates in Section 6.0, Attachment B.

COMBUSTION OF ANALYZER SAMPLE PURGE GAS - CH_4 EMISSION RATE

The TEs have a DRE of 98%. The E_{MAX} of CH_4 from uncombusted CH_4 in each analyzer sample purge gas stream is estimated as follows (using CH_4 from the Feed to Deethanizer Analyzer sample purge gas stream as an example):

$$
\begin{aligned}
E_{MAX}\left(\frac{lb}{hr}\right) &= ER \times (100\% - DRE\%) \\
&= \left(0.00005\ \frac{lb\ CH_4}{hr}\right) \times (100\% - 98\%) \\
&= 1.0 \text{ x } 10^{-6}\ \frac{lb}{hr} CH_4
\end{aligned}
$$

Where ER = Methane Emission Rate in Vent Gas (lb/hr)
DRE = Trace Erase System Destruction Efficiency

The total uncombusted CH_4 in all analyzer sample purge gas streams is $3.0 \text{ x } 10^{-6}$ lb/hr.

The maximum E_{ANN} of CH_4 from uncombusted CH_4 in each analyzer sample purge gas stream is estimated as follows (using CH_4 from the Feed to Deethanizer Analyzer sample purge gas stream as an example):

$$
\begin{aligned}
E_{ANN}\ (tpy) &= ER \times (100\% - DRE\%) \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lb}\right) \\
&= \left(0.00005\ \frac{lb\ CH_4}{hr}\right) \times (100\% - 98\%) \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton\ CH_4}{2{,}000\ lb\ CH_4}\right) \\
&= 4.4 \text{ x } 10^{-6}\ tpy\ CH_4
\end{aligned}
$$

Where ER = Methane Emission Rate in Vent Gas (lb/hr)
DRE = Trace Erase System Destruction Efficiency

The total uncombusted CH_4 in all analyzer sample purge gas streams is $1.0 \text{ x } 10^{-5}$ tpy.

COMBUSTION OF ANALYZER SAMPLE PURGE GAS - N_2O EMISSION RATE

The N_2O emission rate from the TE due to combustion of analyzer sample purge gas is calculated using Equation W-40, 40 CFR Part 98, Subpart W. Equation W-40 uses a sample purge gas heating value of 1.235×10^{-3} MMBtu/scf and an emission factor of 1×10^{-4} kg N_2O/MMBtu.

The molar flow rate of analyzer sample purge gas was provided by the engineering company; therefore, it is not necessary to perform any additional calculations to determine this value. The total maximum hourly molar flow rate of sample purge gas from all analyzer sources combined is 0.0017 lb-mol/hr.

The total maximum hourly N_2O emission rate due to combustion of all compounds in the analyzer sample purge gas is estimated as follows:

$$E_{MAX}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Mo} \times \text{EF} \div \text{HV} \times \text{V}$$

$$= \left(\frac{0.0017\ \text{lb-mol}}{\text{hr}}\right) \times \left(\frac{0.0002\ \text{lb}\ N_2O}{\text{MMBtu}}\right) \times \left(\frac{0.001235\ \text{MMBtu}}{\text{scf}}\right) \times \left(\frac{379.5\ \text{scf}}{\text{lb-mol}}\right)$$

$$= 1.6 \times 10^{-7}\ \frac{\text{lb}\ N_2O}{\text{hr}}$$

Where Mo = Molar Flow Rate (lb-mol/hr)
EF = N_2O Emission Factor
HV = Heating Value of Waste Gas (MMBtu/scf)
V = Standard Molar Volume of Gas (scf/lb-mol)

The total annual N_2O emission rate due to combustion of all compounds in the analyzer sample purge gas is estimated as follows:

$$E_{ANN}\left(\frac{lb}{hr}\right) = Mo \times EF \div HV \times V \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lbs}\right)$$

$$= \left(\frac{0.0017\ lb\text{-}mol}{hr}\right) \times \left(\frac{0.0002\ lb\ N_2O}{MMBtu}\right) \times \left(\frac{0.001235\ MMBtu}{scf}\right) \times$$

$$\left(\frac{379.5\ scf}{lb\text{-}mol}\right) \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton\ N_2O}{2{,}000\ lbs\ N_2O}\right)$$

$$= 7.0 \times 10^{-7}\ tpy\ N_2O$$

Where Mo = Molar Flow Rate (lb-mol/hr)
EF = N_2O Emission Factor
HV = Heating Value of Waste Gas (MMBtu/scf)
V = Standard Molar Volume of Gas (scf/lb-mol)

Table 3.9-1 summarizes the GHG emission rates for each TO from analyzer sample purge gas combustion.

Table 3.9-1
TE GHG Emission Rates
Analyzer Sample Purge Gas Combustion

Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	0.25	1.10
CH_4	3.0E-06	1.0E-05
N_2O	1.6E-07	7.0E-07

The total CO_2e emission rate for each TE from combusting analyzer sample purge gas is estimated by multiplying the speciated emission rates in Table 3.9-1 by the appropriate GWP in Table 3.2-1. Table 3.9-2 summarizes the speciated GHG and CO_2e emission rates for the TEs from combusting analyzer sample purge gas.

Table 3.9-2
TE GHG Emission Rates
Analyzer Sample Purge Gas Combustion

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
TE1	CO_2e	0.25	1.10
TE2	CO_2e	0.25	1.10
Total	**CO_2e**	**0.50**	**2.20**

3.10 MSS ACTIVITIES

Several sources within the Jefferson County NGL Fractionation Plant will experience emissions during plant MSS activities that are in addition to the "normal operation" emission rates described in Sections 3.3 through 3.9 of this application. Waste gases associated with MSS emissions are routed to the flare (EPN: FLR1). For maximum hourly emission estimate purposes, the MSS event with the maximum mass vented is used to determine a maximum hourly MSS vent rate assuming the entire mass may be vented in 1 hour. Annual emission estimates are based on the number of times each activity is expected to occur per year. Details regarding the description of each MSS event, the compounds vented, the frequency, and number of events per year are provided in Section 6.0, Attachment B.

Emissions of GHGs from MSS gas streams routed to the flare during MSS are the result of combustion of carbon compounds in the MSS gas stream, the portion of CH_4 in the MSS gas steam that is not destroyed, and CO_2 in the MSS gas stream that passes through the flare unchanged. The composition of the MSS gas streams routed to the flare was provided by the engineering company. The compositions for the MSS gas streams routed to the flare were generated using a combination of process knowledge and process modeling software. Information on MSS gas stream compositions is provided in the detailed emission estimates in Section 6.0, Attachment B. GHG emission rates from the flare during MSS are estimated using the same calculation methodologies outlined in Section 3.5.2.

Table 3.10-1 summarizes the GHG emission rates for the flare from MSS gas combustion.

Table 3.10-1
Flare GHG Emission Rates for MSS Gas Combustion

Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	125,003.80	5,249.91
CH_4	0.92	0.88
N_2O	0.05	7.13
CO_2e	125,038.62	7,479.94

4.0 REGULATORY APPLICABILITY ANALYSIS

This section addresses applicability of federal air quality regulations with respect to GHG emissions and PSD regulatory review.

4.1 PSD APPLICABILITY

4.1.1 GENERAL PSD STATIONARY SOURCE APPLICABILITY

Federal PSD regulations are codified in CFR Title 40, Part 52, Subpart A, Section 21. PSD regulations are potentially applicable to any existing major stationary source or new major stationary source that emits a regulated NSR pollutant that is located in an area designated as attainment or unclassifiable under Sections 107(d)(1)(A)(ii) or (iii) of the Clean Air Act ("CAA"), as described in 40 CFR §52.21(a)(2). A major stationary source is defined in 40 CFR §52.21(b)(1)(i) as either 1) any stationary source that emits or has the potential to emit 100 tpy or more of any regulated NSR pollutant if it is one of the 26 types of sources listed in 40 CFR §52.21(b)(1)(i)(a), or 2) any stationary sources that emits or has the potential to emit 250 tpy or more of any regulated NSR pollutant. Regulated NSR pollutants, as defined in 40 CFR §52.21(b)(50), include the following:

- CO
- Lead ("Pb")
- Nitrogen Dioxide ("NO_2")
- Ozone ("O_3") – precursors are VOC and NO_X
- PM_{10}
- $PM_{2.5}$ – precursors are SO_2 and NO_X
- SO_2
- Asbestos ("ASB")
- Beryllium ("Be")
- Mercury ("Hg")
- Vinyl chloride ("VC")

- Fluorides
- Sulfuric acid (“H_2SO_4”) mist
- H_2S
- Total reduced sulfur compounds (“TRS”)
- GHGs, which are comprised of the aggregate group of six GHGs: CO_2, N_2O, CH_4, hydrofluorocarbons (“HFCs”), perfluorocarbons (“PFCs”), and sulfur hexafluoride (“SF_6”)

EXISTING SOURCE APPLICABILITY

PSD regulatory review applies to an existing major stationary source if the source performs a project that is considered a major modification that causes a significant emissions increase and a significant net emissions increase of a regulated NSR pollutant, as described in 40 CFR §52.21(a)(2)(iv)(a). The emissions increase calculation may be based on either the comparison of baseline actual emission to potential to emit methodology or the comparison of baseline actual emissions to future potential to emit methodology described in 40 CFR §§52.21(a)(2)(iv)(c) and (d), respectively. A significant emissions increase as defined in 40 CFR §52.21(b)(40), is an increase in emissions of non-GHG or GHG pollutants that is equal to or greater than the rates listed below, as represented in 40 CFR §52.21(b)(23)(i) and 40 CFR §52.21(b)(49)(iii), respectively:

• CO:	100 tpy
• NO_X:	40 tpy
• SO_2:	40 tpy
• Particulate matter (“PM”):	25 tpy
• PM_{10}:	15 tpy
• $PM_{2.5}$:	10 tpy
• O_3:	40 tpy of VOC or NO_X
• Pb:	0.6 tpy
• Fluorides:	3 tpy
• H_2SO_4 mist:	7 tpy

• H_2S:	10 tpy
• TRS:	10 tpy
• Reduced sulfur compounds:	10 tpy
• CO_2e:	75,000 tpy

PSD regulatory review also applies to any existing stationary source that emits of has the potential to emit 100,000 tpy CO_2e or more, when the source performs a project that causes a significant emissions increase and a significant net emissions increase of 75,000 tpy CO_2e or more, as described in 40 CFR §52.21(b)(49)(v)(b).

NEW SOURCE APPLICABILITY

As described in 40 CFR §52.21(b)(1)(i) and 40 CFR §§52.21(b)(49)(iv) and (v), PSD regulatory review applies to a new major stationary source that emits or has the potential to emit pollutants in the quantities described below:

- 100 tpy or more of any regulated NSR pollutant (other than GHGs) if it is one of the 26 types of sources listed in 40 CFR §52.21(b)(1)(i)(a)
- 250 tpy or more of any regulated NSR pollutant (other than GHGs)
- 100,000 tpy CO_2e

4.1.2 JEFFERSON COUNTY NGL FRACTIONATION PLANT PSD APPLICABILITY

The proposed Jefferson County NGL Fractionation Plant will be located at a new site that is not an existing stationary source of GHG or non-GHG pollutants, as described in Section 1.0. Because the site is not an existing stationary source, PSD regulatory review applicability must be determined by comparing potential annual emissions of regulated NSR pollutants from the proposed plant to the PSD major source emission thresholds in 40 CFR §52.21(b)(1)(i) and 40 CFR §§52.21(b)(49)(iv) and (v). If the new project is determined to be a major stationary source for any regulated NSR pollutant (per the comparison in the previous sentence), the potential emission rate of each of the other minor regulated NSR pollutants must be compared to that pollutant's significant emissions threshold in 40 CFR §52.21(b)(23)(i) and 40 CFR §52.21(b)(49)(iii) to determine if the resulting emissions represent a major modification with respect to the remaining pollutants.

As described in Section 1.0, emissions from the proposed plant include the regulated NSR pollutants CO, NO_X, VOC, PM_{10}, $PM_{2.5}$, SO_2, H_2S, TRS, and CO_2e. Table 4-1 provides a summary of the potential emission rates of all regulated NSR pollutants as compared to the major source and significant emission thresholds. As shown in Table 4-1, the proposed project is a major stationary source due to emissions of CO_2e only. Potential emissions of CO, NO_X, VOC, PM_{10}, $PM_{2.5}$, SO_2, H_2S, and TRS from the proposed facility are each below their respective major modification thresholds; therefore, PSD review is not required for any of these non-GHG pollutants. A minor NSR permit application will be submitted to the TCEQ to authorize emissions of CO, NO_X, VOC, PM_{10}, $PM_{2.5}$, SO_2, H_2S, and TRS from the proposed facility.

Table 4.1-1
Comparison of Proposed Project Emission Rates to PSD Major Source and Major Modification Threshold

Pollutant	Emission Rate (tpy)	Major Source Threshold (tpy)	Major Modification Threshold (tpy)
CO_2e	210,687	100,000	75,000
NO_X	32	250	40
CO	66	250	100
VOC	34	250	40
SO_2	22	250	40
PM_{10}	8	250	15
$PM_{2.5}$	7	250	10
H_2S	<1	250	10
TRS	<1	250	10

4.2 PSD REGULATORY REVIEW REQUIREMENTS

Because PSD regulatory review is applicable to the Jefferson County NGL Fractionation Plant as described in Section 4.1.2, the facility must meet the applicable PSD regulatory review requirements contained in 40 CFR §§52.21(c) through (w). This section addresses the PSD regulatory review requirements applicable to the proposed facility.

4.2.1 COMPLIANCE WITH EMISSION LIMITATIONS AND STANDARDS

As described in 40 CFR §52.21(j)(1), any major stationary source or major modification must meet each applicable emission limitation under the State Implementation Plan ("SIP") and each applicable emission standard and standard of performance under 40 CFR parts 60 and 61. Compliance with applicable emission limitations under the TCEQ SIP, New Source Performance Standard ("NSPS") in 40 CFR Part 60, and National Emission Standards for Hazardous Air Pollutants ("NESHAPs") in 40 CFR Part 61 are addressed in the non-GHG minor NSR permit application submitted to the TCEQ.

4.2.2 BEST AVAILABLE CONTROL TECHNOLOGY

As described in 40 CFR §52.21(j)(2) and (3), any major stationary source or major modification must apply BACT for each regulated NSR pollutant that the source would have the potential to emit in significant amounts. The regulated NSR pollutants that the facility will have the potential to emit in significant amounts include only CO_2e. A BACT analysis for CO_2e, which includes emissions of CO_2, CH_4, and N_2O, is included in Section 5.0 of this application.

4.2.3 SOURCE IMPACT ANALYSIS

As described in 40 CFR §52.21(k)(1), a demonstration is required to show that emission increases of regulated NSR pollutants subject to PSD regulatory review associated with the proposed facility will not cause or contribute to air pollution in violation of either of the following:

- Any National Ambient Air Quality Standard (“NAAQS”)
- Any applicable maximum allowable increase over the baseline concentration (“PSD increment”)

The regulated NSR pollutants for which NAAQS have been promulgated include CO, Pb, NO_2, O_3, $PM_{2.5}$, PM_{10}, and SO_2. The PSD increments include emissions of NO_2, $PM_{2.5}$, PM_{10}, and SO_2, as provided in 40 CFR §52.21(c). Estimates of ambient air quality for both NAAQS and PSD increment evaluations must be based on applicable air quality models specified in Appendix W of 40 CFR Part 51, as described in 40 CFR §52.21(l)(1).

As described in 40 CFR §52.21(a)(2)(ii), the requirements of paragraphs (j) through (r) of 40 CFR §52.21 apply to new major stationary sources or major modifications. The only regulated NSR pollutant for which the project is considered a new major stationary source or major modification is CO_2e, as described in Section 4.1.2, Although CO_2e is a regulated NSR pollutant, a source impact analysis is not required for this pollutant because no NAAQS or PSD increment exists for this pollutant. As described in Section IV page 48 of the USEPA’s PSD and Title V Permitting Guidance for Greenhouse Gases, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews.

4.2.4 AMBIENT AIR QUALITY ANALYSIS

As described in 40 CFR §52.21(m)(1)(i), an ambient air quality analysis must be submitted with any permit application for each pollutant that the source has the potential to emit in a significant amount. This analysis must include air quality monitoring data as required by 40 CFR §§52.21(m)(1)(ii) and (iii), unless exempted from the requirements of 40 CFR §52.21(m) as described in 40 CFR §52.21(i)(5). Exemptions from the monitoring requirements for a pollutant may be granted by the permitting authority in the following cases:

- 40 CFR §52.21(i)(5)(i) – The emissions increase of the pollutant from the new source would result in air quality impacts less than the concentration listed in 40 CFR 52.21(i)(5)(i)(a) through (k) for that pollutant.
- 40 CFR §52.21(i)(5)(ii) – The existing concentrations of the pollutant in the area the new source would affect are less than the concentration listed in 40 CFR 52.21(i)(5)(i)(a) through (k) for that pollutant.
- 40 CFR 52.21(i)(5)(iii) – The pollutant is not listed in 40 CFR 52.21(i)(5)(i).

To determine if the first exemption above applies, the source impact analysis using dispersion modeling must be conducted, as described in Section 4.2.3. To determine if the second exemption above applies a combination of dispersion modeling of existing sources and existing ambient monitoring data may be used.

As discussed in Section 4.1.2, the only pollutant that has the potential to be emitted in a significant amount from the proposed facility is CO_2e. Emissions of CO_2e are exempt from the ambient air quality analysis requirements per the exemption in 40 CFR §52.21(i)(5)(iii).

4.2.5 SOURCE INFORMATION

As described in 40 CFR §52.21(n), the owner or operator of the proposed source is required to submit all information necessary to perform any analysis or make any determination required under the PSD regulations.

Information pertaining to the design and construction of the source required by 40 CFR §52.21(n)(1) includes the following:

- A description of the nature, location, design capacity, and typical operating schedule of the proposed source.
- Specifications and drawings showing the source design and plant layout.
- A detailed schedule of construction of the source.

- A detailed description as to what system of continuous emission reduction is planned, emission estimates, and any other information necessary to determine BACT would be applied.

Information concerning design and construction of the source is provided in this GHG PSD permit application and the non-GHG PSD permit application submitted to the TCEQ. Information regarding the nature, location, design capacity, typical operating schedule, and drawings of plant design and layout of the proposed source are provided in Sections 1.0, 2.0, and 3.0 of this application. Proposed start of construction and start of operation dates are included in the PI-1 form in Section 6.0, Attachment A. Information regarding emission estimates and BACT for GHG pollutants is included in Sections 3.0 and 5.0 of this application, respectively.

Information pertaining to ambient air quality impacts from the proposed source and other sources in the area affected by the source as required by 40 CFR §52.21(n)(2) includes the following:

- The air quality impact of the source.
- Meteorological and topographical data necessary to estimate the impact of the source.
- The air quality impacts, and nature and extent of any or all general commercial, residential, industrial, and other growth which has occurred since August 7, 1977.

Air quality impacts associated with the proposed facility and any general commercial, residential, industrial, or other growth are covered by the requirements addressed in Sections 4.2.3 and 4.2.4 of this application. This requirement applies to non-GHG pollutants only, as noted in the referenced sections. As noted in the referenced sections, non-GHG pollutants will not be emitted from the proposed facility in significant amounts; therefore, this type of review is not required.

4.2.6 ADDITIONAL IMPACTS ANALYSES AND FEDERAL CLASS I AREA IMPACTS

As described in 40 CFR §52.21(o), an analysis is required of the impacts that may result from the proposed source:

- 40 CFR §52.21(o)(1) - An analysis of impairment to visibility, soils, and vegetation that would occur as a result of the source and general commercial, residential, industrial and other growth associated with the source.
- 40 CFR §52.21(o)(2) - An analysis of the air quality impact for the area as a result of general commercial, residential, industrial and other growth associated with the source.
- 40 CFR §52.21(o)(3) - Visibility monitoring may be required in any Federal Class I area near the proposed source.

The analyses described in 40 CFR §52.21(o), are required for regulated NSR pollutants that are emitted in significant amounts. The only regulated NSR pollutant proposed to be emitted in a significant amount is CO_2e (or GHGs), as described in Section 4.1.2. As described in the USEPA PSD and Title V Permitting Guidance for Greenhouse Gases, Section IV (Other PSD Requirements), dated March 2011, it is not necessary to assess impacts from GHGs in the context of the additional impacts analysis or the Class I area impacts. However, it is the understanding of DCP from a recent meeting with USEPA Region 6 personnel, that these analyses are now requested for the project even when the only pollutants emitted in a significant amount are GHGs. Therefore, DCP has included the analyses in this permit application.

As described in the same USEPA guidance document described in the previous paragraph, analysis of the effects of GHG emissions with respect to Class I areas, soils, and vegetation are typically conducted for GHG emissions orders of magnitude larger than GHG emissions proposed in individual PSD permit reviews. Also, it is not possible to quantify the exact impacts attributable to a specific stationary source with the analysis tools that are currently available. Therefore, the only pollutants that remain to be reviewed in this analysis are the non-GHG regulated NSR pollutants that are not emitted in significant amounts.

The non-GHG regulated NSR pollutants that will be emitted by the proposed facility include CO, NO_X, VOC, PM_{10}, $PM_{2.5}$, SO_2, H_2S, and TRS. These non-GHG pollutants are considered to have insignificant impacts to the environment surrounding the Jefferson County NGL Fractionation Plant site. Potential increases of these non-GHG pollutants are regulated by the TCEQ minor source permitting programs which are approved by the USEPA based on State Implementation Plan ("SIP") submittals from the TCEQ. Based on these approvals, it was determined by the USEPA that emissions from permitted minor sources are protective of the NAAQS and general air quality. The primary NAAQS for each pollutant are considered by the USEPA to be protective of public health. The secondary NAAQS for each pollutant are considered by the USEPA to be protective of public welfare (decreased visibility and damage to animals, crops, vegetation, and buildings). Because non-GHG pollutant emissions from the Jefferson County NGL Fractionation Plant will be authorized under the USEPA approved minor source permitting programs and these programs assure protection of the NAAQS, the non-GHG emissions are not expected to cause detrimental effects to soils and vegetation.

DCP does not expect any significant commercial, residential, or industrial growth associated with the proposed Jefferson County NGL Fractionation Plant. The number of personnel employed at the facility when it becomes operational is expected to be approximately 75. The majority of the personnel employed at the facility will likely be hired from the existing population in the region. Therefore, significant commercial or residential growth that might occur with a significant population increase is not expected. The feedstock for the facility and the produced products will be transferred from the feedstock sources and to the product customers via pipelines. Therefore, construction of the proposed facility is not expected to result in additional industrial growth in the area. Because minimal residential and little to no commercial or industrial growth is expected, the air quality impacts associated with this growth are expected to be minimal to non-existent.

The nearest Class I area to the proposed Jefferson County NGL Fractionation Plant is the Breton Wilderness Areas, located approximately 480 kilometers from the proposed facility location. USEPA guidance on page E.16 of the "New Source Review Workshop Manual" dated October

1990 states that all major sources or major modifications that propose to located within 100 kilometers of a Class I area "may affect" the Class I area. In addition, this guidance document also states that major sources which locate further than 100 kilometers from a Class I area may have adverse impacts on the Class I area. Because the proposed Jefferson County NGL Fractionation Plant is not a major source or major modification with respect to non-GHG pollutants and will be located more than 100 kilometers from a Class I area, the emissions are not expected to have an impact on visibility or Air Quality Related Values ("AQRVs") in a Class I area. Furthermore, visibility monitoring should not be required in any Class I area due to non-GHG emissions from the proposed facility.

4.2.7 ENVIRONMENTAL IMPACT STATEMENTS

As described in 40 CFR §52.21(s), whenever any proposed source is subject to action by a Federal Agency which might necessitate preparation of an environmental impact statement ("EIS") pursuant to the National Environmental Policy Act ("NEPA"), USEPA review conducted pursuant to NEPA shall be coordinated with the broad environmental reviews under NEPA and section 309 of the CAA to the maximum extent feasible and reasonable. Under Section 309 of the CAA, USEPA is required to review and publicly comment on the environmental impacts of major Federal actions, proposed environmental regulations, and other proposed major actions. However, 40 CFR §124.9(b)(6) specifically states that PSD permits are not subject to the EIS provisions of NEPA. Therefore, DCP is not required to prepare an EIS for the PSD permit application for the proposed facility.

4.3 GHG MANDATORY REPORTING RULE

The applicability and requirements of the GHG MRR are contained in 40 CFR Part 98. The GHG MRR is applicable to facilities that meet any of the following criteria:

- 40 CFR §98.2(a)(1) – A facility that contains any source category that is listed in Table A-3 of 40 CFR Part 98, Subpart A.

- 40 CFR §98.2(a)(2) – A facility that contains any source category that is listed in Table A-4 of 40 CFR Part 98, Subpart A and emits a combined 25,000 metric tons CO_2e from stationary fuel combustion units, miscellaneous uses of carbonate, and all applicable source categories in Tables A-3 and A-4.
- 40 CFR §98.2(a)(3) – A facility that meets all three of the conditions listed below:
    - The facility is does not contain a source category listed in either Table A-3 or Table A-4 of 40 CFR Part 98, Subpart A.
    - The aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is 30 MMBtu/hr or greater.
    - The facility emits 25,000 metric tons CO_2e or more per year in combined emissions from all stationary fuel combustion sources.
- 40 CFR §98.2(a)(4) – A supplier that is listed in Table A-5 of 40 CFR Part 98, Subpart A.

The GHG MRR is potentially applicable to the Jefferson County NGL Fractionation Plant because it meets the following criteria:

- 40 CFR §98.2(a)(2) – The facility is listed in 40 CFR Part 98, Subpart A Table A-4, because it belongs to the Petroleum and Natural Gas Systems ("40 CFR Part 98, Subpart W") source category and will have the potential to emit 25,000 metric tons CO_2e from a combination of 40 CFR Part 98, Subpart W sources and General Stationary Fuel Combustion Sources ("40 CFR Part 98, Subpart C").
- 40 CFR §98.2(a)(4) – The facility is listed in 40 CFR Part 98, Subpart A Table A-5, because it belongs to the Natural Gas and NGL Suppliers ("40 CFR Part 98, Subpart NN") supplier category.

The Jefferson County NGL Fractionation Plant will comply with the applicable requirements of the GHG MRR.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY

Under the CAA, a PSD permit must contain emissions limitations based on application of BACT for each regulated NSR pollutant. A determination of BACT for GHGs should be conducted in the same manner as it is done for any other NSR regulated pollutant.

The CAA §169(3) defines BACT as:

> *"An emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant."*

Each new source at the facility is subject to a BACT review using the USEPA Top-Down BACT process to determine BACT for GHGs. A general overview of the USEPA Top-Down BACT process is provided in Section 5.1.

Any technology selected as BACT cannot be less efficient than any technology required under a NSPS or Maximum Achievable Control Technology ("MACT") Standard. The only NSPS or MACT standard for GHG currently effective or proposed is for coal fired power plants. The Jefferson County NGL Fractionation Plant is not a coal fired power plant; therefore, no applicable NSPS or MACT limitations apply.

5.1 TOP-DOWN BACT PROCESS OVERVIEW

The Top-Down BACT review process is detailed in the draft 1990 NSR Workshop Manual. The Top-Down BACT review process is broken down into the following five steps.

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The first step in the Top-Down BACT review process is to identify all available control technologies, including alternative processes and practices. USEPA has divided potentially applicable control technologies to be considered during the BACT review into the following three categories[1]:

- Inherently Lower-Emitting Processes/Practices/Designs;
- Add-on Controls; and
- Combinations of Inherently Lower Emitting Processes/Practices/Designs and Add-on Controls.

GHG BACT analyses will focus primarily on lower emitting process/practices/designs through the evaluation and implementation of energy efficiency measures and practices.

Evaluation of control options should include those options applied at other source categories with exhaust streams that are similar to the source category in question. DCP has determined which control technologies are considered available using the following sources:

- The USEPA's RACT/BACT/LAER Clearinghouse;
- The USEPA's GHG Control Measures White Papers for Large Industrial/Commercial/ Institutional Boilers and Refineries;
- ENERGY STAR Industrial Sector Energy Guides and Plant Energy Performance Indicators (benchmarks); and
- Other BACT determinations for similar processes and equipment.

Although many control technologies and alternative processes may eventually be eliminated in subsequent steps, Step 1 should document all potential and relevant options.

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[1] USEPA's PSD and Title V Permitting Guidance for Greenhouse Gases, USEPA-457/B-11-001, March 2011.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

The list of potential control technologies and strategies outlined in Step 1 is then evaluated for technical feasibility. USEPA considers technologies to be technically feasible if:

- It has been demonstrated and operated successfully at a similar source; and
- It is available and applicable to the source under review.

USEPA does not generally consider technologies still in the pilot or research and development phases to be technically feasible due to availability.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

The control technologies considered technically feasible are then ranked according to effectiveness. Effectiveness considers both total emissions reductions and increased energy efficiency.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

At this stage, the control technologies identified as both available and technically feasible are evaluated for environmental, economic, and energy impacts. Control technologies may be eliminated at this stage if any of the impacts are determined to be too severe.

STEP 5: SELECT BACT

The top ranked control technology determined to be technologically feasible and having acceptable environmental, economic, and energy impacts should be selected as BACT. Multiple control technologies may be selected as BACT if feasible.

5.2 BACT FOR GREENHOUSE GASES

USEPA regulated GHGs include CO_2, CH_4, and N_2O and are expressed as CO_2e[2]. This BACT analysis will evaluate all three pollutants for each source type. Some control technologies, such as combustion control of CH_4 containing streams, will also generate other GHGs. In these cases, the control technology that produces the greatest overall reduction in CO_2e will generally be selected as BACT.

5.3 SOURCES TO BE EVALUATED

The following sources emit GHG and will be addressed in this BACT analysis.

Table 5.3-1
Sources to be Evaluated

EPN	Source Type	Section
TO1	Amine Regenerator Vent	5.3.3
TO2	Amine Regenerator Vent	5.3.3
ENG1	Firewater Pump Engine	5.3.4
ENG2	Emergency Generator Engine	5.3.4
TO1	Thermal Oxidizer	5.3.5
TO2	Thermal Oxidizer	5.3.5
HOH1	Hot Oil Heater	5.3.6
HOH2	Hot Oil Heater	5.3.6
HTR1	Molecular Sieve Dehydrator Regeneration Heater	5.3.7
HTR2	Molecular Sieve Dehydrator Regeneration Heater	5.3.7
FUG1	Fugitives	5.3.8
FUG2	Fugitives	5.3.8
TE1	Trace Erase System	5.3.8
TE2	Trace Erase System	5.3.8
FLR1	VOC Flare	5.3.9

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[2] HFCs, PFCs, and SF_6 are also regulated GHGs, but are not emitted by the DCP SET Frac; therefore, are not discussed.

5.3.1 PLANT-WIDE CONSIDERATIONS

The BACT analysis for plant wide GHG emission reductions focuses on two categories: energy efficiency measures and carbon capture and sequestration ("CCS").

5.3.1.1 ENERGY EFFICIENCY CONSIDERATION

There are several available GHG emission control strategies that will be applied on a plant wide basis. These control strategies are addressed in this section.

The plant was designed with heat and process integration in mind for increased energy efficiency. Where feasible, the plant utilizes available process streams to transfer heat or cooling which reduces combustion heating and refrigeration requirements in the process. For example, process-to-process heat exchangers are used to transfer energy between process streams to reduce heat duty requirements. Shell and tube heat exchangers are utilized to heat process streams which otherwise would require combustion heat sources. Shell and tube heat exchangers are also utilized to cool process streams where appropriate which reduces the refrigeration.

The plant will insulate equipment (vessels), piping, and components in both hot and cold service. This will prevent heat loses to the atmosphere from equipment containing hot streams or excessive warming of equipment containing cold streams. In this way, the need for additional heat input and refrigeration is minimized.

Process control instrumentation and pneumatic components will be operated using compressed air rather than fuel gas or off-gas; therefore, no GHG emissions will be emitted to the atmosphere from these components.

The plant will be built using new, state-of-the-art equipment and process instrumentation and controls. DCP's operating and maintenance policies will maintain all equipment according to manufacturer specifications in order to keep all equipment operating efficiently.

5.3.1.2 CARBON CAPTURE AND SEQUESTRATION

CCS involves four main steps:

- Capture of CO_2 from sources including combusted exhaust streams and amine regenerator vent vapors;
- Clean-up of emission streams to remove impurities (potentially sulfur and water) to meet pipeline specifications and compress the CO_2 to pipeline conditions;
- Transport of compressed CO_2 to a sequestration site; and
- Sequestration of CO_2.

CAPTURE OF WASTE STREAMS

The potential CO_2 eligible for CCS application is summarized in Table 5.3.1-1 and includes emissions from the amine vents prior to combustion in the TOs, the heater exhaust, and the trace erase systems. Assuming a 90% capture efficiency of CO_2, CCS would decrease CO_2 emissions by 171,861 tpy.

Table 5.3.1-1
Summary of CO_2 Emissions Available for CCS

Emission Source	Ton Per Year Reduction Per Source[1] (tpy)	Number of Sources at the Facility	Total Ton Per Year Reduction (tpy)
Hot Oil Heaters	78,421.92	2	156,843.84
Molecular Sieve Dehydrator Regeneration Heaters	12,958.76	2	25,917.52
Amine Regenerator Vents	4,096.86	2	8,193.72
Trace Erase Systems	1.10	2	2.20
Total			**190,957**
Total Captured (90%)			**171,861**

[1] Detailed emission rate calculations are in Section 6.0, Attachment B.

CLEANUP OF WASTE STREAMS

In order to remove the CO_2 from the heater exhaust streams, remove impurities from the CO_2 stream, and compress the CO_2 stream to pipeline temperature and pressure, several additions must be made to the plant. New equipment would, at a minimum, include electric motors for compression of the purified CO_2 stream, heat exchangers to cool the exhaust streams from the combustion sources, additional amine units for purification of the CO_2 stream, and additional separation equipment including scrubbers and mole sieves. The additional equipment needed to purify and compress the CO_2 stream would have an estimated capital cost of $82,377,400 (see Table D-1 in Attachment D).

The annualized costs associated with the new equipment are estimated using USEPA's Air Pollution Control Cost Manual, Sixth Edition – USEPA/452/B-02-001. The direct annual operating cost of the new equipment includes factors such as operator labor to operate the equipment, routine maintenance, cost of the amine for the new amine systems, and electricity to run the new equipment. The indirect annual operating cost of the new equipment includes administrative charges, property taxes, insurance, and the capital recovery cost of the total capital cost of the equipment. The total annualized cost of the CO_2 capture and cleanup equipment is estimated to be $24,606,860 (see Table D-2 in Section 6, Attachment D).

TRANSPORT

DCP has determined that the nearest facility capable of accepting an anthropogenic CO_2 stream is the Denbury Green Pipeline, approximately 1.5 miles from the Jefferson County NGL Fractionation Plant (See Denbury Green Pipeline Map in Section 6.0, Attachment D). The capital cost of constructing the pipeline from the DCP plant to the Green Pipeline is estimated using the National Energy Technology Laboratory's document "Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs" (DOE/NETL-2010/1447, March 2010), will be approximately $2,627,597 (see Table D-3 in Section 6.0, Attachment D).

The annual operating costs of the pipeline are estimated using the "Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs" as referenced above. Using this methodology, the annual operating costs of the pipeline will be approximately $12,948. In addition, the capital recovery cost is estimated using the methodology in USEPA’s Air Pollution Control Cost Manual, as referenced above with a cost of approximately $427,641 (see Table D-3 in Section 6.0, Attachment D). Therefore, the total annualized cost of the pipeline will be approximately $440,589 per year:

$$\begin{aligned} C_T &= C_{OC} + C_{CRC} \\ &= \frac{\$12,948}{yr} + \frac{\$427,641}{yr} \\ &= \$440,589/yr \end{aligned}$$

Where: C_T = Total Annualized Cost ($/yr)
C_{OC} = Total Operating Cost ($/yr)
C_{CRC} = Total Capital Recovery Cost ($/yr)

SEQUESTRATION

Obtaining an estimate of the cost of utilizing the Green Pipeline would require DCP to enter into a contract with Denbury. DCP does not wish to enter into a formal business agreement with Denbury; therefore, DCP has conservatively assumed that utilizing the Denbury Green Pipeline would have a cost of $0 per ton CO_2 sequestered. The total capital cost of implementing CCS is therefore estimated to be:

$$\begin{aligned} C_T &= C_E + C_P + C_S \\ &= \$82,377,400 + \$2,627,597 + \$0 \\ &= \$85,004,997 \end{aligned}$$

Where C_T = Total CCS Capital Cost ($)
C_E = Total Equipment Capital Cost ($)
C_P = Total Pipeline Capital Cost ($)
C_S = Total Sequestration Capital Cost ($)

Implementing CCS would increase the total capital cost of the project by 17%.

The total annualized cost of implementing CCS is estimated to be:

$$\begin{aligned} C_T &= C_E + C_P + C_S \\ &= \frac{\$24,606,860}{yr} + \frac{\$440,589}{yr} + \frac{\$0}{yr} \\ &= \$25,047,449/yr \end{aligned}$$

Where C_T = Total Annualized CCS Cost ($/yr)
C_E = Total Annualized Equipment Cost ($/yr)
C_P = Total Annualized Pipeline Cost ($/yr)
C_S = Total Annualized Sequestration Cost ($/yr)

The total annual cost per ton of CO_2 reduced would be:

$$\begin{aligned} C &= \frac{C_A}{ER} \\ &= \frac{\$25,047,449/yr}{171,861\ tpy} \\ &= \$145.74/ton \end{aligned}$$

Where C = Cost per Ton CO_2 Reduced ($/ton)
C_A = Total Annualized CCS Cost ($/yr)
ER = Ton CO_2 per Year Reduced (tpy)

DCP believes these costs to be economically unreasonable; therefore, does not propose the use of CCS as BACT.

5.3.2 AMINE UNIT VENT GASES

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The review of the sources listed in Section 5.1 identified the following list of potential GHG control technologies for the amine unit vent gases:

- CCS;
- Routing amine unit vent gases to a control device; and
- Selection of an amine with low regeneration heating requirements.

CCS

CCS would be used to capture the CO_2 from the amine unit vent gases, purify, compress, and send the CO_2 via pipeline to either a storage location or another pipeline for use in enhanced oil recovery ("EOR"). CCS is discussed in detail in Section 5.3.1.2.

ROUTING VENT GASES TO CONTROL

Routing the amine unit vent gases to a control device would decrease the CH_4 emissions due to the amine system by the applicable destruction efficiency. At the plant, the two available control devices are the facility flare with a DRE of 98% and the TO with a DRE of 99.9%. However, destruction of the CH_4 will result in the creation of CO_2.

SELECTION OF AMINE

The selection of the amine solution for use in the amine unit determines the amount of heat needed to regenerate the amine. Therefore, this directly effects CO_2 emissions from the hot oil system.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

All control technologies identified in Step 1 are considered technically feasible. Therefore, each control technology is considered in Step 3.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

As discussed in Section 5.3.1.2, CCS has negative energy, environmental, and economic effects; therefore, is not selected as BACT. The remaining control technologies are selected as BACT. Therefore, no ranking is necessary.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

CCS

CCS is discussed in detail in Section 5.3.1.2 and has been determined to be economically unreasonable. The discussion includes information for all CO_2 sources at the facility.

ROUTING VENT GASES TO CONTROL

Routing the amine unit vent gases to either control device is assumed to have no energy and economic impacts. However, the destruction of CH_4 will form a stoichiometrically equivalent amount of CO_2. As discussed in Section 3.2, CO_2 has a lower GWP than CH_4. Therefore, routing the amine unit vent gases to control will decrease the total CO_2e emissions associated with the amine unit vent gases.

AMINE SELECTION

Use of an amine solution with a low regeneration heat requirement lowers operational expenses, heat load, and GHG emission rates. However, proper operation of the plant requires an inlet gas stream with as little CO_2 as possible. Therefore, a low regeneration heat amine is desirable.

STEP 5: SELECT BACT

BACT for the amine unit vent gases has been selected as follows:

- Routing the amine unit vents to the TO; and
- Use of an amine with low regeneration heating requirements.

ROUTING VENT GASES TO CONTROL

The amine unit vent gases from each train will be routed to the corresponding TO. As stated in Step 4, this technology results in lower CH_4 emissions which have a higher GWP than CO_2.

AMINE SELECTION

The amine unit will utilize 25% Diethanolamine, which has a low heat regeneration requirement. Due to the heat regeneration requirement, less CO_2 will be emitted from combustion sources generating the heat in the plant hot oil system.

As discussed above, BACT for the amine unit vent gases includes combustion control in a TO. Therefore, the emission limitation proposed is only for the combustion of the amine unit vent gases in the TO. DCP proposes the following emission limitations and monitoring for each TO, as associated with amine unit vent gases:

Table 5.3.2-1
Amine Unit Vent Gases CO_2e BACT Emission Limitations and Monitoring Proposal

EPN	Emission Limit (ton CO_2e/yr)	Time Period	Monitoring Proposal
TO1	5,954.29	Annual And Rolling 12-month Total	Maximum Annual Waste Stream Volume Processed
TO2	5,954.29	Annual And Rolling 12-month Total	Maximum Annual Waste Stream Volume Processed

The emission limitations from the combustion of fuel gas and other process vents in the TO are discussed in Section 5.3.4. Specific proposals for monitoring and work practice standards for the TO are also discussed in Section 5.3.4.

5.3.3 EMERGENCY FIREWATER PUMP AND EMERGENCY GENERATOR ENGINES

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The review of the sources listed in Section 5.1 identified the following list of potential GHG control technologies for the firewater pump and emergency generator engines:

- CCS;
- Selection of efficient engines;
- Use of efficient process controls, good combustion practices, and scheduled maintenance; and
- Use of low carbon fuel.

CCS

CCS would be used to capture the CO_2 from the engine exhaust, purify, compress, and send the CO_2 via pipeline to either a storage location or another pipeline for use in EOR. CCS is discussed in detail in Section 5.3.1.2.

ENERGY EFFICIENT ENGINES

Selection of energy efficient engines would reduce the total heat input of the plant and the emissions associated with the engines. Therefore, energy efficient engines are identified as a potential control technology.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance would ensure the engine is operating as efficiently as possible. Careful control of each engine's operation would also minimize CO_2 emissions. Furthermore, proper operation of each engine would extend its useful life. DCP would also follow the manufacturer's recommended maintenance schedule to maintain proper and efficient operation of each engine.

LOW CARBON FUELS

Selection of a lower carbon fuel, such as natural gas, would result in less CO_2 formation during combustion. Therefore, a lower carbon fuel is identified as a potential control technology.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

CCS

CCS requires a continuous exhaust stream to be considered technically feasible. As the firewater pump and emergency generator engines will only be operated intermittently, the exhaust from these engines is not a good candidate for CCS. Therefore, DCP wishes to eliminate CCS from further consideration for the firewater pump and emergency generator engines.

LOW CARBON FUELS

The engines will fire diesel stored on-site in a storage tank. An engine firing natural gas may be more efficient, as natural gas is the fuel with the lowest carbon content. However, these engines are required to be available for use at any time, including when the plant will not be supplied with natural gas. To meet this need and minimize fuel storage costs, DCP has selected diesel-fired engines for their reliability and availability during an emergency, such as during an emergency shutdown or electrical outage.

Both remaining control technologies are considered technically feasible. Therefore, these control technologies are considered in Step 3.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

As discussed in Section 5.3.1.2 and Step 2, CCS and the use of natural gas are considered technically infeasible. The remaining control technologies are selected as BACT. Therefore, no ranking is necessary.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

ENERGY EFFICIENT ENGINES

The engines are required to be available for use at any time in the unlikely event of an emergency. To meet this need, DCP has selected diesel-fired engines for their reliability and availability.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance will ensure the engines are operating as efficiently as possible. Furthermore, proper operation of the engines will extend the useful life of the engine and have positive environmental and energy conservation effects.

STEP 5: SELECT BACT

DCP proposes the use of the following technologies as BACT:

- Selection of efficient firewater pump and emergency generator engines; and
- Use of good combustion practices.

ENERGY EFFICIENT ENGINES

The selected engines are required to be available for use at any time in the event of an emergency, including when natural gas is not available. A diesel-fired pump and emergency generator engines have been selected for their availability, reliability, and minimum fuel storage requirements.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The Plant design includes specifications for state of the art process instrumentation and controls. A list of applicable good combustion practices is included in Section 6.0, Attachment D. DCP will follow the recommended maintenance from the engine manufacturer.

DCP proposes the following emission limitations and monitoring for each engine:

Table 5.3.3-1
Firewater Pump and Emergency Generator Engines
CO_2e BACT Emission Limitations and Monitoring Proposal

EPN	Emission Limit (ton CO_2e/yr)	Time Period	Monitoring Proposal
ENG1	28.62	Monthly	Hours of Operation
ENG2	28.62	Monthly	Hours of Operation

DCP also proposes the following monitoring and work practice requirements for each engine:

<u>Fire Water Pump Engine</u>

- Fuel used in the engine will meet the requirements of 40 CFR 80.510(b) regarding sulfur content (15 ppmw maximum) and a minimum Centane Index of 40 or maximum aromatic content of 35% by volume.
- Install a non-resettable hour meter prior to startup of the engine.
- Operate and maintain the engine and control device according to the manufacturer's emission-related written instructions.
- Engine purchased will be certified to meet the applicable emission standards in 40 CFR 60.4205(c).
- Engine may be operated for the purpose of maintenance checks and readiness testing for up to 100 hours per year.
- Operating hours of the engine in emergency situations are not limited.

<u>Emergency Generator Engine</u>

- Fuel used in the engine will meet the requirements of 40 CFR 80.510(b) regarding sulfur content (15 ppmw maximum) and a minimum Centane Index of 40 or maximum aromatic content of 35% by volume.
- Install a non-resettable hour meter prior to startup of the engine.

- Operate and maintain the engine and control device according to the manufacturer's emission-related written instructions.
- Engine purchased will be certified to meet the applicable emission standards in 40 CFR 60.4205(b).
- Engine may be operated for the purpose of maintenance checks and readiness testing for up to 100 hours per year.
- Operating hours of the engine in emergency situations are not limited.

5.3.4 THERMAL OXIDIZERS

The TOs are used to control waste gas streams from the amine vent and other process vent streams. This section addresses BACT for the TOs regarding combustion of fuel gas and process vents other than those from the amine unit. BACT for the amine unit vent streams controlled by the TOs are addressed in Section 5.3.2.

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The review of the sources listed in Section 5.1 identified the following list of potential GHG control technologies for the TOs:

- CCS;
- Use of a regenerative TO;
- Use of efficient process controls, good combustion practices, and scheduled maintenance; and
- Selection of low carbon fuel.

CCS

CCS would be used to capture the CO_2 from the TO exhaust, purify, compress, and send the CO_2 via pipeline to either a storage location or another pipeline for use in EOR. CCS is discussed in detail in Section 5.3.1.2.

REGENERATIVE THERMAL OXIDIZER

The use of regenerative thermal oxidizers ("RTO") would allow the plant to recover heat from the exhaust stream, reducing the overall heat input of the plant. This option would decrease the emissions from the plant due to less fuel combustion required to generate heat.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance would ensure the TOs are operating as efficiently as possible. Careful control of TO operation would also minimize CO_2 emissions. Furthermore, proper operation of the TOs would extend their useful life. DCP would also follow the manufacturer's recommended maintenance schedule to maintain proper and efficient operation of the TOs.

LOW CARBON FUELS

Selection of a lower carbon fuel would result in less CO_2 formed during combustion. Therefore, a lower carbon fuel is identified as a potential control technology.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

The use of an RTO is considered technically infeasible. Use of an RTO requires a waste stream with a very low heating value (less than 50 Btu/scf). The waste gases from the process streams to be controlled have a much higher heating value (approximately 800 - 1,000 Btu/scf) than those normally burned in an RTO. Use of an RTO to burn a stream with a heating value in the range of 800 to 1,000 Btu/scf could lead to the TO overheating, creating an unsafe situation. Therefore, DCP has eliminated the use of an RTO from this BACT analysis. The remaining control technologies identified in Step 1 are considered technically feasible.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

As discussed in Section 5.3.1.2, CCS has negative energy, environmental, and economic effects; therefore, is not selected as BACT. The remaining control technologies are all selected as BACT. Therefore, no ranking is necessary.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

CCS

CCS is discussed in detail in Section 5.3.1.2 and has been determined to be economically unreasonable. This discussion includes information for all CO_2 sources at the facility.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance will ensure the TOs are operating as efficiently as possible. Furthermore, proper operation of the TOs will extend their useful life and have only positive environmental and energy effects.

LOW CARBON FUELS

The proposed TOs will burn pipeline quality natural gas which has the lowest carbon content of available fuels. No lower carbon content fuels have been identified. Therefore, the use of natural gas will result in the lowest CO_2 emissions from the TOs.\

STEP 5: SELECT BACT

BACT for the TOs has been selected as follows:

- Use of efficient process controls, good combustion practices, and scheduled maintenance; and
- Selection of low carbon fuel.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The plant design includes specifications for state of the art process instrumentation and controls. A list of applicable good combustion practices is included in Section 6, Attachment D. DCP will follow the recommended maintenance schedule from the TO manufacturer.

LOW CARBON FUELS

The proposed TOs will burn pipeline quality natural gas which has the lowest carbon content of available fuels. No lower carbon content fuels have been identified.

DCP proposes the following emission limitations and monitoring for the TOs from the combustion of fuel gas and waste gas other than the amine unit vents:

Table 5.3.4-1
TO CO_2e BACT Emission Limitations and Monitoring Proposal

EPN	Emission Limit (ton CO_2e/yr)	Time Period	Monitoring Proposal
TO1	2,869.38	Annual	See list below.
TO2	2,869.38	Annual	See list below.

DCP proposes the following monitoring and work practice requirements for the TOs, which address both fuel gas and waste gas combustion:

- Perform annual maintenance as recommended by the manufacturer and maintain records of significant maintenance activities.
- Monitor the temperature at the firebox exit to ensure 99.9% DRE for VOC and methane. Minimum temperature which demonstrates 99.9% DRE to be determined by initial testing. Reset minimum temperature determination annually following the annual testing.
- Initial performance test to establish firebox exit temperature necessary to demonstrate 99.9% DRE, annual performance testing thereafter.
- Continuous monitoring of firebox exit temperature, reduced to an hourly and daily average, to demonstrate compliance with the specified DRE.
- Monitor fuel usage continuously using a totalizing fuel flow meter (calibrated annually) and record daily fuel consumption.
- Monitor flow rate of waste gas continuously using a totalizing flow meter (calibrated annually) and record daily waste gas flow.

- Sample waste gas quarterly to determine composition and heat content.
- Semiannual analysis of plant natural gas fuel to determine the higher heating value in Btu/scf, molecular weight, and carbon content, or certification from natural gas fuel supplier containing the same information. One sample at the fuel source will be valid for all combustion devices.
- Monthly calculation of CO_2, CH_4, N_2O, and CO_2e emissions using methods in the MRR, permit application, total fuel combusted in the preceding month for each thermal oxidizer, and the semi-annual natural gas fuel analysis.
- Calculation of rolling 12-month average for CO_2, CH_4, N_2O, and CO_2e using the monthly calculation for these compounds.

5.3.5 HOT OIL HEATERS

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The review of the sources listed in Section 5.1 identified the following list of potential GHG control technologies for the hot oil heaters:

- CCS;
- Use of efficient process controls, good combustion practices, and scheduled maintenance; and
- Selection of low carbon fuel.

CCS

CCS would be used to capture the CO_2 from the hot oil heater exhaust, purify it, compress it, and send the CO_2 via pipeline to either a storage location or another pipeline for use in EOR. CCS is discussed in detail in Section 5.3.1.2.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance would ensure the hot oil heaters are operating as efficiently as possible. Careful control of hot oil heater operation would also minimize CO_2 emissions. Furthermore, proper operation of the hot oil heaters would extend their useful life. DCP would also follow the manufacturer's recommended maintenance schedule to maintain proper and efficient operation of the hot oil heaters.

LOW CARBON FUELS

Selection of a lower carbon fuel would result in less CO_2 formation during combustion. Therefore, a lower carbon fuel is identified as a potential control technology.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

The control technologies identified in Step 1 are considered technically feasible. Therefore, each control technology is considered in Step 3.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

As discussed in Section 5.3.1.2, CCS has negative energy, environmental, and economic effects; therefore, is not selected as BACT. The remaining control technologies are all selected as BACT. Therefore, no ranking is necessary.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

CCS

CCS is discussed in detail in Section 5.3.1.2 and has been determined to be economically unreasonable. This discussion includes information for all CO_2 sources at the facility.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance would ensure the hot oil heaters are operating as efficiently as possible. Furthermore, proper operation of the hot oil heaters will extend their useful life and have only positive environmental and energy effects.

LOW CARBON FUELS

The proposed hot oil heaters will burn pipeline quality natural gas which has the lowest carbon content of available fuels. No lower carbon content fuels have been identified.

STEP 5: SELECT BACT

BACT for the hot oil heaters has been selected as follows:

- Use of efficient process controls, good combustion practices, and scheduled maintenance; and
- Selection of low carbon fuel.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The plant design includes specifications for state of the art process instrumentation and controls. Process instrumentation and controls for the hot oil heaters include fuel gas monitoring for consumption and temperature monitoring of the hot oil to insure the heaters fire sufficiently to maintain the appropriate oil temperature for heat requirements. A list of applicable good combustion practices is included in Section 6.0, Attachment D. DCP will follow the recommended maintenance schedule from the hot oil heater manufacturer.

LOW CARBON FUELS

The proposed hot oil heaters will burn pipeline quality natural gas which has the lowest carbon content of available fuels. No lower carbon content fuels have been identified. Therefore, the use of natural gas will result in the lowest CO_2 emissions from the hot oil heaters

DCP proposes the following emission limitations and monitoring for the hot oil heaters:

Table 5.3.5-1
Hot Oil Heater CO_2e BACT Emission Limitations and Monitoring Proposal

EPN	Emission Limit (ton CO_2e/yr)	Time Period	Monitoring Proposal
HOH1	78,499.50	Annual	See list below.
HOH2	78,499.50	Annual	See list below.

DCP also proposes an efficiency based BACT limit of 85% for each hot oil heater. The following monitoring and work practice requirements proposed by DCP will assist in maintaining the BACT emission and efficiency limits of the hot oil heaters:

- Use natural gas as fuel, which is a low carbon fuel.
- Install insulation where feasible on heater surfaces.
- Perform annual maintenance as recommended by manufacturer and maintain records of significant maintenance activities.
- Clean heater burner tips and convection tubes as needed.
- Install a totalizing fuel flow meter (calibrated annually) to continuously monitor fuel usage and record daily fuel consumption.
- Install a non-resettable hour meter to continuously record hours of operation.
- Semiannual analysis of plant natural gas fuel to determine the higher heating value in Btu/scf, molecular weight, and carbon content, or certification from natural gas fuel supplier containing the same information. One sample at the fuel source will be valid for all combustion devices.
- Install and operate combustion air controls to limit excess air.
- Install and operate an oxygen analyzer to allow manual adjustment to optimize fuel/air mixture and limit excess air.
- Oxygen analyzer will continuously monitor and record oxygen concentration with an averaging period of 15 minutes and maximum limit of 15% O_2.

- Monthly calculation of CO_2, CH_4, N_2O, and CO_2e emissions using methods in the MRR, permit application, total fuel combusted in the preceding month for each hot oil heater, and the semiannual natural gas fuel analysis.
- Calculation of rolling 12-month average for CO_2, CH_4, N_2O, and CO_2e using the monthly calculation for these compounds.

5.3.6 MOLECULAR SIEVE DEHYDRATOR REGENERATION HEATERS

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The review of the sources listed in Section 5.1 identified the following list of potential GHG control technologies for the molecular sieve dehydrator regeneration heaters:

- CCS;
- Use of efficient process controls, good combustion practices, and scheduled maintenance; and
- Selection of low carbon fuel.

CCS

CCS would be used to capture the CO_2 from the molecular sieve dehydrator regeneration heater exhaust, purify, compress, and send the CO_2 via pipeline to either a storage location or another pipeline for use in EOR. CCS is discussed in detail in Section 5.3.1.2.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance would ensure the molecular sieve dehydrator regeneration heaters are operating as efficiently as possible. Careful control of regeneration heater operation would also minimize CO_2 emissions. Furthermore, proper operation of the molecular sieve dehydrator regeneration heaters would extend their useful life. DCP would also follow the manufacturer's recommended maintenance schedule to maintain proper and efficient operation of the molecular sieve dehydrator regeneration heaters.

LOW CARBON FUELS

Selection of a lower carbon fuel would result in less CO_2 formation during combustion. Therefore, a lower carbon fuel is identified as a potential control technology.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

The control technologies identified in Step 1 are considered technically feasible. Therefore, each control technology is considered in Step 3.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

As discussed in Section 5.3.1.2, CCS has negative energy, environmental, and economic effects; therefore, is not selected as BACT. Both remaining control technologies are all selected as BACT. Therefore, no ranking is necessary.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

CCS

CCS is discussed in detail in Section 5.3.1.2 and has been determined to be economically unreasonable. This discussion includes information for all CO_2 sources at the facility.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance would ensure the molecular sieve dehydrator regeneration heaters are operating as efficiently as possible. Furthermore, proper operation of the molecular sieve dehydrator regeneration heaters will extend their useful life and have only positive environmental and energy effects.

LOW CARBON FUELS

The proposed molecular sieve dehydrator regeneration heaters will burn pipeline quality natural gas which has the lowest carbon content of available fuels. No lower carbon content fuels have been identified.

STEP 5: SELECT BACT

BACT for the molecular sieve dehydrator regeneration heaters has been selected as follows:

- Use of efficient process controls, good combustion practices, and scheduled maintenance; and
- Selection of low carbon fuel.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The Plant design includes specifications for state of the art process instrumentation and controls. Process instrumentation and controls for the molecular sieve dehydrator regeneration heaters includes mole sieve bed temperature monitors and moisture analyzers to insure proper regeneration of the mole sieve dehydration beds. A list of applicable good combustion practices is included in Section 6.0, Attachment D. DCP will follow the recommended maintenance schedule from the regeneration heater manufacturer.

LOW CARBON FUELS

The proposed regeneration heaters will burn pipeline quality natural gas which has the lowest carbon content of available fuels. No lower carbon content fuels have been identified.

DCP proposes the following emission limitations and monitoring for the regeneration heaters:

Table 5.3.6-1
Regeneration Heater CO_2e BACT Emission Limitations and Monitoring Proposal

EPN	Emission Limit (ton CO_2e/yr)	Time Period	Monitoring Proposal
HTR1	12,970.05	Annual	See list below.
HTR2	12,970.05	Annual	See list below.

DCP proposes the following monitoring and work practice requirements to assist in maintaining the BACT emission limits of the molecular sieve dehydrator regeneration heaters:

- Perform annual maintenance as recommended by the manufacturer and maintain records of significant maintenance activities.
- Install a totalizing fuel flow meter (calibrated annually) to continuously monitor fuel usage and record daily fuel consumption.
- Install a non-resettable hour meter to continuously record hours of operation.
- Monitor exhaust oxygen content using a portable stack gas analyzer to allow manual adjustment to optimize fuel/air mixture and limit excess air.
- Exhaust oxygen content will be monitored semiannually for a period of 15 minutes and recorded at the beginning and end of the 15 minute period. If monitoring indicates an exhaust oxygen content of greater than 15% O_2, then the air/fuel mixture will be manually adjusted and the exhaust monitored again after adjustment to verify the oxygen content does not exceed 15% O_2.
- Exhaust oxygen content will be limited to a maximum of 15% O_2 based on the semiannual monitoring.
- Monthly calculation of CO_2, CH_4, N_2O, and CO_2e emissions using methods in the MRR, permit application, total fuel combusted in the preceding month for each molecular sieve dehydration heater, and the semiannual natural gas fuel analysis.
- Calculation of a rolling 12-month average for CO_2, CH_4, N_2O, and CO_2e using the monthly calculation for these compounds.

5.3.7 PLANT FUGITIVES

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The review of the sources listed in Section 5.1 identified the following list of potential GHG control technologies for the fugitives:

- Leakless component designs; and
- Leak detection and repair program.

LEAKLESS DESIGN

The use of leakless fugitive components would involve installing pumps designed to be leakless, welded flanges, and otherwise sealing potential sources of fugitive emissions. Therefore, leakless design is identified as a potential control technology.

LEAK DETECTION AND REPAIR PROGRAM

The implementation of a leak detection and repair program will ensure any potential emissions, due to leaking components, are promptly identified and repaired. Therefore, a leak detection and repair program is identified as a potential control technology.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Both control technologies identified in Step 1 are considered technically feasible. Therefore, each control technology is considered in Step 3.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

Both control technologies identified in Step 1 are selected as BACT. Therefore, no ranking is necessary.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

Both control technologies identified in Step 1 have the potential to reduce GHG emissions by up to 100%. Therefore, both control technologies have positive environmental impacts.

STEP 5: SELECT BACT

BACT for the fugitives has been selected as follows:

- Leakless component designs; and
- Leak detection and repair program.

LEAKLESS DESIGN

DCP will use leakless fugitive components, where economical and safe, to eliminate potential sources of fugitive emissions. Examples of leakless fugitive component designs available for use at the plant are listed in TCEQ's Guidance Document for Equipment Leak Fugitives, Page 17, in Section 6, Attachment D.

LEAK DETECTION AND REPAIR PROGRAM

DCP will implement a leak detection and repair program utilizing instrument monitors and a leak definition of 500 parts per million by volume that will control most fugitive equipment leaks by up to 97%. The leak detection and repair program utilized is defined by TCEQ as their "28LAER" program and is detailed in TCEQ's Guidance Document for Equipment Leak Fugitives, Page 13, in Section 6.0, Attachment D.

DCP proposes the following emission limitations and monitoring for fugitives:

Table 5.3.7-1
Fugitive CO_2e BACT Emission Limitations and Monitoring Proposal

EPN	Emission Limit (tons CO_2e/yr)	Time Period	Monitoring Proposal
FUG1	297.15	Annual	Quarterly with Instrument Monitor
FUG2	297.15	Annual	Quarterly with Instrument Monitor

5.3.8 ANALYZER SAMPLE PURGE GAS/TRACE ERASE SYSTEM

A combination of the plant flare and the TE systems are used to safely dispose of intermittent sample purge gas from various analyzers used throughout the process in both trains. It is not technically feasible to control these sample purge gas streams with the TO due to their intermittent nature. The significant portion of each analyzer sample purge gas stream is routed to the plant flare for control; however, a small portion (approximately 1.2%) of each sample purge gas stream is routed to the TE system in each train for control. Use of a flare in combination with the TE system minimizes CO_2 emissions by converting CH_4 with a GWP of 21 to CO_2 with a GWP of 1. Control technologies for emissions to and from the flare are addressed in Section 5.3.9.

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The review of the sources listed in Section 5.1 identified the following list of potential GHG control technologies for the TE systems:

- CCS;
- Routing this small stream of analyzer sample purge gas to the flare; and
- Minimization of releases sent to TE systems

CCS

CCS would be used to capture the CO_2 from the TE systems, purify, compress, and send the CO_2 via pipeline to either a storage location or another pipeline for use in EOR. CCS is discussed in detail in Section 5.3.1.2.

ROUTING SMALL PORTION OF ANALYZER SAMPLE PURGE GAS TO FLARE

Routing the small portion of the analyzer sample purge gas to the flare would result in elimination of the TE emission sources while maintaining similar control efficiency for the purge gas streams. Therefore routing these small streams to the flare is identified as a potential control technology.

MINIMIZATION OF RELEASES

Minimization of the small analyzer sample purge gas releases to the TE system would minimize GHG emissions from the TE systems. Therefore, minimization of releases to the TE systems is identified as a potential control technology.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

CCS

CCS is discussed in detail in Section 5.3.1.2 and has been determined to be economically unreasonable. This discussion includes information for all CO_2 sources at the facility.

ROUTING ANALYZER SAMPLE PURGE GAS TO FLARE

Routing the small portion of the analyzer sample purge gas streams to the flare would result in backpressure on the analyzer systems. Backpressure on the analyzer systems would result in inaccurate operation of the analyzer systems; therefore, routing these streams to the flare is considered technically infeasible.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

The remaining control technology is all selected as BACT. Therefore, no ranking is necessary.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

MINIMIZATION OF RELEASES

Minimization of the small analyzer sample purge gas releases to the TE systems is the only remaining control technology. Therefore, minimizing releases to the TE systems is identified as an effective control technology.

STEP 5: SELECT BACT

Minimization of releases of the small portion of the analyzer sample purge gas streams to the TE systems has been selected as BACT. DCP will operate the plant in such a way as to minimize analyzer sample purge gas streams sent to the TE systems. This method of operation will result in less GHG emissions from the TE systems. DCP proposes to minimize GHG emissions from the TE systems using the following monitoring and work practice requirements:

- Maintain the process analyzers and TE systems according to the manufacturer instructions with the frequency recommended by the manufacturer.
- Maintain records of maintenance performed on the process analyzers.
- Maintain records of maintenance performed on the TE systems.

DCP proposes the following emission limitations and monitoring for TE systems:

Table 5.3.8-1
TE Systems CO_2e BACT Emission Limitations and Monitoring Proposal

EPN	Emission Limit (tons CO_2e/yr)	Time Period	Monitoring Proposal
TE1	1.10	Annual	Maintenance according to manufacturer instructions.
TE2	1.10	Annual	Maintenance according to manufacturer instructions.

5.3.9 FLARE

The plant flare is used to safely dispose of intermittent waste streams that are not technically feasible to control with the TO, emergency releases of hydrocarbon, and MSS events from two trains. Use of a flare minimizes CO_2 emissions by converting CH_4 with a GWP of 21 to CO_2 with a GWP of 1.

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The review of the sources listed in Section 5.1 identified the following list of potential GHG control technologies for the flare:

- CCS;
- Minimization of releases sent to flare; and
- Use of low carbon fuel for pilot and sweep gas.

CCS

CCS would be used to capture the CO_2 from the flare, purify, compress, and send the CO_2 via pipeline to either a storage location or another pipeline for use in EOR. CCS is discussed in detail in Section 5.3.1.2.

MINIMIZATION OF RELEASES

Minimization of emergency and MSS releases sent to the flare would minimize GHG emissions from the flare. Therefore, minimization of releases to the flare is identified as a potential control technology.

LOW CARBON FUELS

Selection of a lower carbon fuel would result in less CO_2 formed during combustion. Therefore a lower carbon furl is identified as a potential control technology.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

CCS

Currently, capture and control of post-combustion CO_2 from the flare is technologically infeasible due to the height and heat content the flare. Therefore, CCS for GHG from the flare is infeasible. Both remaining control technologies identified in Step 1 are considered technically feasible.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

Both remaining control technologies are all selected as BACT. Therefore, no ranking is necessary.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

MINIMIZATION OF RELEASES

Minimization of emergency and MSS releases sent to the flare would minimize GHG emissions from the flare. Therefore, minimizing releases to the flare is identified as an effective control technology.

LOW CARBON FUELS

Selection of a low carbon fuel, such as natural gas, would result in less CO_2 formation during combustion. Therefore, a low carbon fuel is identified as an effective control technology.

STEP 5: SELECT BACT

BACT for the flare has been selected as follows:

- Minimization of releases sent to flare; and
- Use of natural gas for pilot and sweep gas.

MINIMIZATION OF RELEASES

DCP will operate the plant in such a way as to minimize release streams sent to the flare. This method of operation will result in less GHG emissions from the flare. DCP will minimize release streams sent to the flare using the following methods:

- Intermittent emissions to the flare will be minimized by proper maintenance of the process equipment according to written mechanical integrity program procedures and limiting sample and analyzer purges to only those required to maintain the desired product quality.
- Maintaining the plant processes at regular intervals as described in the permit application will avoid additional MSS operations, thereby minimizing emissions to the flare.
- Process fluids in equipment that requires maintenance will be routed into the process until no longer operationally feasible; thereby minimizing the amount of process material routed to the flare.
- Emergency emissions to the flare will be minimized by proper process design and training of process operators to avoid significant overpressure incidents to the flare.

LOW CARBON FUELS

The proposed flare will burn pipeline quality natural gas which has the lowest carbon content of available fuels. No lower carbon fuels have been identified.

DCP proposes the following emission limitations and monitoring for flare:

Table 5.3.9-1
Flare CO_2e BACT Emission Limitations and Monitoring Proposal

EPN	Emission Limit (tons CO_2e/yr)	Time Period	Monitoring Proposal
FLR1	9,447.29	Annual	See list below.

The flare is 98% efficient in controlling emissions of CH_4 and VOC. DCP proposes the following monitoring and work practice requirements to assist in maintaining the destruction efficiency and BACT emission limits of the flare:

- Design and operation in accordance with 40 CFR 60.18.
- Continuously monitor for the presence of pilot flame using a thermocouple or the equivalent device.
- Totalizing fuel flow meter, calibrated quarterly, to determine the volume of natural gas fuel combusted in the flare pilots.
- Totalizing flow meter, calibrated quarterly, to measure the flare header purge gas and waste gas volume sent to the flare.
- Monthly calculation of CO_2, CH_4, N_2O, and CO_2e emissions using methods in the MRR, permit application, monthly fuel gas combusted, semiannual fuel gas analysis, and the monthly waste gas volume.
- A gas analyzer (Gas Chromatograph or equivalent) will be installed on the header piping directly upstream of the inlet to the flare to measure composition and heat input of the flare header purge gas and waste gas for each intermittent and MSS vent stream.

6.0 ATTACHMENTS

The following information is included in this section:

- Attachment A – TCEQ Forms and Tables
- Attachment B – Detailed GHG Emission Estimates
- Attachment C – Supporting Documentation
- Attachment D – Supporting BACT Information

ATTACHMENT A

TCEQ FORMS AND TABLES

PI-1 – Permit Application
Table 1(a) – Emission Point Summary
Table 4 – Combustion Units
Table 6 – Boilers and Heaters
Table 8 – Flares
Table 29 – Reciprocating Engines

Form PI-1

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: DCP Midstream, LP		
Texas Secretary of State Charter/Registration Number (*if applicable*):		
B. Company Official Contact Name: Lynn C. Ward		
Title: Senior Environmental Specialist		
Mailing Address: 662 S. Shelby		
City: Carthage	State: TX	ZIP Code: 75633
Telephone No.: 903-694-4114	Fax No.: 903-690-0041	E-mail Address: lcward@dcpmidstream.com
C. Technical Contact Name: Lynn C. Ward		
Title: Senior Environmental Specialist		
Company Name: DCP Midstream, LP		
Mailing Address: 662 S. Shelby		
City: Carthage	State: TX	ZIP Code: 75633
Telephone No.: 903-694-4114	Fax No.: 903-690-0041	E-mail Address: lcward@dcpmidstream.com
D. Site Name: Jefferson County NGL Fractionation Plant		
E. Area Name/Type of Facility: Jefferson County NGL Fractionation Plant	☒ Permanent ☐ Portable	
F. Principal Company Product or Business: Natural Gas Liquids		
Principal Standard Industrial Classification Code (SIC): 1321		
Principal North American Industry Classification System (NAICS): 211112		
G. Projected Start of Construction Date: September 2013		
Projected Start of Operation Date: January 2015		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: See Area Map		
City/Town: Beaumont	County: Jefferson	ZIP Code: 77707
Latitude (nearest second): 29°59'27.7"	Longitude (nearest second): -94°06'44.6"	

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I. Applicant Information (continued)	
I. Account Identification Number (leave blank if new site or facility):	
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): CN 601229917	
L. Regulated Entity Number (RN):	
II. General Information	
A. Is confidential information submitted with this application? If *Yes*, mark each **confidential** page **confidential** in large red letters at the bottom of each page.	☐ YES ☒ NO
B. Is this application in response to an investigation or enforcement action? If *Yes*, attach a copy of any correspondence from the agency.	☐ YES ☒ NO
C. Number of New Jobs: estimated 75	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
Senator: Tommy Williams	District No.: 4
Representative: Joe Deshotel	District No.: 22
III. Type of Permit Action Requested	
A. Mark the appropriate box indicating what type of action is requested. Initial ☒ Amendment ☐ Revision (30 TAC 116.116(e)) ☐ Change of Location ☐ Relocation ☐	
B. Permit Number (if existing):	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* Construction ☒ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Prevention of Significant Deterioration ☒ Hazardous Air Pollutant Major Source ☐ Plant-Wide Applicability Limit ☐ Other:______________________________	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c)	☐ YES ☒ NO

III. Type of Permit Action Requested (continued)	
E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.	☐ YES ☒ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):	
Street Address:	

City:	County:	ZIP Code:
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:

3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If *No*, attach detailed information.	☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?	☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.	
List:	
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.):	

1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.

FOP Significant Revision ☐ FOP Minor ☐ Application for an FOP Revision ☐ To Be Determined ☒

Operational Flexibility/Off Permit Notification ☐ Streamlined Revision for GOP ☐ None ☐

III. Type of Permit Action Requested (continued)	
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. (check all that apply)	
GOP Issued ☐	GOP application/revision application submitted or under APD review ☐
SOP Issued ☐	SOP application/revision application submitted or under APD review ☐

IV. Public Notice Applicability	
A. Is this a new permit application or a change of location application?	☒ YES ☐ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☐ YES ☒ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☐ YES ☒ NO
If *Yes*, list the affected state(s) and/or Class I Area(s).	
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E 3.	
1. Is there any change in character of emissions in this application?	☐ YES ☐ NO
2. Is there a new air contaminant in this application?	☐ YES ☐ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
F. List the total annual emission increases associated with the application (*list* **all** *that apply and attach additional sheets as needed*):	
Volatile Organic Compounds (VOC):	
Sulfur Dioxide (SO_2):	
Carbon Monoxide (CO):	
Nitrogen Oxides (NO_x):	
Particulate Matter (PM):	
PM $_{10}$ microns or less (PM_{10}):	
PM $_{2.5}$ microns or less ($PM_{2.5}$):	
Lead (Pb):	
Hazardous Air Pollutants (HAPs):	
Other speciated air contaminants **not** listed above	Carbon Dioxide Equivalent (CO2e): 210,687

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V. Public Notice Information (complete if applicable)

A. Public Notice Contact Name Lynn Ward

Title: Senior Environmental Specialist

Mailing Address: 662 S. Shelby

City: Carthage | State: TX | ZIP Code: 75633

Telephone No.: 903-694-4114

B. Name of the Public Place: Beaumont Public Library

Physical Address (No P.O. Boxes): 801 Pearl Street

City: Beaumont | County: Jefferson | ZIP Code: 77701

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: Jeff Branick

Mailing Address: 1149 Pearl Street

City: Beaumont | State: TX | ZIP Code: 77701

2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? *(For Concrete Batch Plants)* ☐ YES ☐ NO

Presiding Officers Name(s)

Title:

Mailing Address:

City: | State: | ZIP Code:

3. Provide the name, mailing address of the chief executive of the city for the location where the facility is or will be located.

Chief Executive: Mayor Becky Ames

Mailing Address: P.O. Box 3827

City: Beaumont | State: TX | ZIP Code: 77704-3827

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

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VII. Technical Information			
B. Are any schools located within 3,000 feet of this facility?			☐ YES ☒ NO
C. Maximum Operating Schedule:			
Hours: 24	Day(s): 365	Week(s): 52	Year(s): 8,760 hrs
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.			
N/A - New Facility			
E. Does this application involve any air contaminants for which a *disaster review* is required?			☐ YES ☒ NO
F. Does this application include a pollutant of concern on the *Air Pollutant Watch List (APWL)*?			☐ YES ☒ NO
VIII. State Regulatory Requirements **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment**. *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*			
A. Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?			☒ YES ☐ NO
B. Will emissions of significant air contaminants from the facility be measured?			☒ YES ☐ NO
C. Is the Best Available Control Technology (BACT) demonstration attached?			☒ YES ☐ NO
D. Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?			☒ YES ☐ NO
IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*			
A. Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?			☒ YES ☐ NO
B. Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?			☐ YES ☒ NO
C. Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?			☒ YES ☐ NO

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

TCEQ

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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: Lynn Ward

Signature: Lynn Ward

Original Signature Required

Date: 2/25/2013

Table 1(a)

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	25-Feb-13	**Permit No.:**		**Regulated Entity No.:**	
Area Name:	Jefferson County NGL Fractionation Plant			**Customer Reference No.:**	CN601229917

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

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) POUND**	**(B) TPY**
HOH1	HOH1	Hot Oil Heater 1	CO_2e	21,386.89	78,499.50
HOH2	HOH2	Hot Oil Heater 2	CO_2e	21,386.89	78,499.50
HTR1	HTR1	Regeneration Heater 1	CO_2e	4,301.25	12,970.05
HTR2	HTR2	Regeneration Heater 2	CO_2e	4,301.25	12,970.05
ENG1	ENG1	500 hp Diesel Firewater Pump Engine	CO_2e	572.34	28.62
ENG2	ENG2	500 hp Diesel Emergency Generator Engine	CO_2e	572.34	28.62
FLR1	FLR1	VOC Flare - Routine	CO_2e	449.16	1,967.35
FLR1	FLR1	VOC Flare - MSS	CO_2e	125,038.62	7,479.94
TO1	TO1	Thermal Oxidizer 1	CO_2e	2,014.87	8,823.67
TO2	TO2	Thermal Oxidizer 2	CO_2e	2,014.87	8,823.67
TE1	TE1	Trace Erase System 1	CO_2e	0.25	1.10
TE2	TE2	Trace Erase System 2	CO_2e	0.25	1.10

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	25-Feb-13	**Permit No.:**		**Regulated Entity No.:**	
Area Name:	Jefferson County NGL Fractionation Plant			**Customer Reference No.:**	CN601229917

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

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) POUND**	**(B) TPY**
FUG1	FUG1	Train 1 Fugitives	CO_2e	67.84	297.15
FUG2	FUG2	Train 2 Fugitives	CO_2e	67.84	297.15

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	25-Feb-13	**Permit No.:**	0	**Regulated Entity No.:**	0
Area Name:	Jefferson County NGL Fractionation Plant			**Customer Reference No.:**	CN601229917

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

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			**4. UTM Coordinates of Emission Point**			**Source**							
						5. Building	**6. Height Above**	**7. Stack Exit Data**			**8. Fugitives**		
EPN (A)	**FIN (B)**	**Name (C)**	**Zone**	**East (Meters)**	**North (Meters)**	**Height (Ft.)**	**Ground (Ft.)**	**Diameter (Ft.) (A)**	**Velocity (FPS) (B)**	**Temp. (°F) (C)**	**Length (Ft.) (A)**	**Width (Ft.) (B)**	**Axis Degrees (C)**
HOH1	HOH1	Hot Oil Heater 1	15	392639	3318375	-	130.0	6.0	31.4	380.0			
HOH2	HOH2	Hot Oil Heater 2	15	392642	3318144	-	130.0	6.0	31.4	380.0			
HTR1	HTR1	Regeneration Heater 1	15	392639	3318403	-	110.0	4.0	20.9	700.0			
HTR2	HTR2	Regeneration Heater 2	15	392641	3318171	-	110.0	4.0	20.9	700.0			
ENG1	ENG1	500 hp Diesel Firewater Pump Engine	15	392603	3318176	-	12.0	0.7	119.1	787.0			
ENG2	ENG2	500 hp Diesel Emergency Generator Engine	15	392901	3318247	-	12.0	0.3	457.0	1011.0			
FLR1	FLR1	VOC Flare	0	392608	3318659	-	200.0	2.5	65.6	1832.0			
TO1	TO1	Thermal Oxidizer 1	15	392641	3318349	-	55.0	5.0	8.9	750.0			
TO2	TO2	Thermal Oxidizer 2	15	392644	3318118	-	55.0	5.0	8.9	750.0			
TE1	TE1	Trace Erase System 1	15	392680	3318124	-	14.0	0.01	0.01	275.0			
TE2	TE2	Trace Erase System 2	15	392677	3318355	-	14.0	0.01	0.01	275.0			
FUG1	FUG1	Train 1 Fugitives	15	392711	3318316	-	10.0	-	-	Ambient			
FUG2	FUG2	Train 2 Fugitives	15	392714	3318085	-	10.0	-	-	Ambient			

EPN = Emission Point Number
FIN = Facility Identification Number

Table 4 – Combustion Units

TABLE 4

COMBUSTION UNITS

OPERATIONAL DATA

Number from flow diagram: TO1	Model Number(if available): TBD
Name of device: Thermal Oxidizer	Manufacturer TBD

CHARACTERISTICS OF INPUT

Waste Material*	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
	1. Refer to attachment B			
	2.			
	3.			
	4.			
	5.			

Gross Heating Value of Waste Material (Wet basis if applicable)	Btu/lb 3,120	Air Supplied for Waste Material	Minimum SCFM (70°F & 14.7 psia) TBD	Maximum SCFM(70°F & 14.7 psia) TBD

Waste Material of Contaminated Gas	Total Flow Rate lb/hr		Inlet Temperature °F	
	Minimum Expected	Design Maximum 1,145	Minimum Expected	Design Maximum TBD

Fuel	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
	1. Natural Gas			214
	2.			
	3.			
	4.			

Gross Heating Value of Fuel	Btu/lb 23242	Air Supplied for Fuel	Minimum SCFM (70°F & 14.7 psia) TBD	Maximum SCFM(70°F & 14.7 psia) TBD

*Describe how waste material is introduced into combustion unit on an attached sheet. Supply drawings, dimensioned and to scale to show clearly the design and operation of the unit.

FORM PI-2 (72-9)

TABLE 4
(continued)

COMBUSTION UNITS

CHARACTERISTICS OF OUTPUT				
Flue Gas Released	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
	1. Refer to Table 1(a)			
	2.			
	3.			
	4.			
	5.			
Temperature at Stack Exit °F	Total Flow Rate lb/hr		Velocity at Stack Exit ft/sec	
750	Minimum Expected	Maximum Expected TBD	Minimum Expected	Maximum Expected 8.9

COMBUSTION UNIT CHARACTERISTICS		
Chamber Volume from Drawing ft^3	Chamber Velocity at Average Chamber Temperature ft/sec	Average Chamber Temperature °F
TBD	TBD	TBD
Average Residence Time sec	Exhaust Stack Height ft	Exhaust Stack Diameter ft
TBD	55	5
ADDITIONAL INFORMATION FOR CATALYTIC COMBUSTION UNITS		
Number and Type of Catalyst Elements	Catalyst Bed Velocity ft/sec	Max. Flow Rate per Catalytic Unit (Manufacturer's Specifications) Specify Units
N/A	N/A	N/A

Attach separate sheets as necessary providing a description of the combustion unit, including details regarding principle of operation and the basis for calculating its efficiency. Supply an assembly drawing, dimensioned and to scale, to show clearly the design and operation of the equipment. If the device has bypasses, safety valves, etc., specify when such bypasses are to be used and under what conditions. Submit explanations on control for temperature, air flow rates, fuel rates, and other operating variables.

TABLE 4

COMBUSTION UNITS

OPERATIONAL DATA

Number from flow diagram: TO2

Model Number(if available): TBD

Name of device: Thermal Oxidizer

Manufacturer TBD

CHARACTERISTICS OF INPUT

	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
Waste Material*	1. Refer to attachment B			
	2.			
	3.			
	4.			
	5.			

Gross Heating Value of Waste Material (Wet basis if applicable)	Btu/lb 3,120	Air Supplied for Waste Material	Minimum SCFM (70°F & 14.7 psia) TBD	Maximum SCFM(70°F & 14.7 psia) TBD

	Total Flow Rate lb/hr		Inlet Temperature °F	
	Minimum Expected	Design Maximum	Minimum Expected	Design Maximum
Waste Material of Contaminated Gas		1,145		TBD

	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
Fuel	1. Natural Gas			214
	2.			
	3.			
	4.			

Gross Heating Value of Fuel	Btu/lb 23242	Air Supplied for Fuel	Minimum SCFM (70°F & 14.7 psia) TBD	Maximum SCFM(70°F & 14.7 psia) TBD

*Describe how waste material is introduced into combustion unit on an attached sheet. Supply drawings, dimensioned and to scale to show clearly the design and operation of the unit.

FORM PI-2 (72-9)

TABLE 4
(continued)

COMBUSTION UNITS

CHARACTERISTICS OF OUTPUT				
Flue Gas Released	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
	1. Refer to Table 1(a)			
	2.			
	3.			
	4.			
	5.			
Temperature at Stack Exit °F 750	Total Flow Rate lb/hr		Velocity at Stack Exit ft/sec	
	Minimum Expected	Maximum Expected TBD	Minimum Expected	Maximum Expected 8.9

COMBUSTION UNIT CHARACTERISTICS		
Chamber Volume from Drawing ft^3 TBD	Chamber Velocity at Average Chamber Temperature ft/sec TBD	Average Chamber Temperature °F TBD
Average Residence Time sec TBD	Exhaust Stack Height ft 55	Exhaust Stack Diameter ft 5
ADDITIONAL INFORMATION FOR CATALYTIC COMBUSTION UNITS		
Number and Type of Catalyst Elements N/A	Catalyst Bed Velocity ft/sec N/A	Max. Flow Rate per Catalytic Unit (Manufacturer's Specifications) Specify Units N/A

Attach separate sheets as necessary providing a description of the combustion unit, including details regarding principle of operation and the basis for calculating its efficiency. Supply an assembly drawing, dimensioned and to scale, to show clearly the design and operation of the equipment. If the device has bypasses, safety valves, etc., specify when such bypasses are to be used and under what conditions. Submit explanations on control for temperature, air flow rates, fuel rates, and other operating variables.

Table 6 – Boilers and Heaters

FORM PI-2(74-7)

TABLE 6

BOILERS AND HEATERS

Type of Device:	Hot Oil Heater, HOH1	Manufacturer:	TBD
Number from flow diagram:	TBD	Model Number:	TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	100%		Average	Design Maximum 2,964 (scfm)
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 1006.68 (Btu/scf)	Average _____ scfm* ___% excess (vol)	Design Maximum ______ scfm * ______% excess (vol)

HEAT TRANSFER MEDIUM

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

OPERATING CHARACTERISTICS

Ave. Fire Box Temp. at max. firing rate	Fire Box Volume(ft.^{3}), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
6 (ft)	130 (ft)	(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp°F	scfm
			31.4	380	33,585

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	Refer to Attachment B, Heater Calculations

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

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

*Standard Conditions: 70°F,14.7 psia

FORM PI-2(74-7)

TABLE 6

BOILERS AND HEATERS

Type of Device:	Hot Oil Heater, HOH2	Manufacturer:	TBD
Number from flow diagram:	TBD	Model Number:	TBD

<table>
<tr><th colspan="5">CHARACTERISTICS OF INPUT</th></tr>
<tr><td>Type Fuel</td><td>Chemical Composition
(% by Weight)</td><td>Inlet Air Temp °F
(after preheat)</td><td colspan="2">Fuel Flow Rate
(scfm* or lb/hr)</td></tr>
<tr><td rowspan="3">Natural Gas</td><td rowspan="3">100%</td><td></td><td>Average</td><td>Design Maximum
2,964 (scfm)</td></tr>
<tr><td>Gross Heating Value of Fuel</td><td colspan="2">Total Air Supplied and Excess Air</td></tr>
<tr><td>(specify units)
1006.68 (Btu/scf)</td><td>Average
_____ scfm*
___% excess (vol)</td><td>Design Maximum
______ scfm *
______% excess (vol)</td></tr>
</table>

<table>
<tr><th colspan="7">HEAT TRANSFER MEDIUM</th></tr>
<tr><td>Type Transfer Medium</td><td colspan="2">Temperature °F</td><td colspan="2">Pressure (psia)</td><td colspan="2">Flow Rate (specify units)</td></tr>
<tr><td>(Water, oil, etc.)</td><td>Input</td><td>Output</td><td>Input</td><td>Output</td><td>Average</td><td>Design Maxim</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

<table>
<tr><th colspan="4">OPERATING CHARACTERISTICS</th></tr>
<tr><td>Ave. Fire Box Temp. at max. firing rate</td><td>Fire Box Volume(ft.^{3}), (from drawing)</td><td>Gas Velocity in Fire Box (ft/sec) at max firing rate</td><td>Residence Time in Fire Box at max firing rate (sec)</td></tr>
<tr><td></td><td></td><td></td><td></td></tr>
</table>

<table>
<tr><th colspan="6">STACK PARAMETERS</th></tr>
<tr><td>Stack Diameters</td><td>Stack Height</td><td colspan="2">Stack Gas Velocity (ft/sec)</td><td>Stack Gas</td><td>Exhaust</td></tr>
<tr><td rowspan="2">6 (ft)</td><td rowspan="2">130 (ft)</td><td>(@Ave.Fuel Flow Rate)</td><td>(@Max. Fuel Flow Rate)</td><td>Temp °F</td><td>scfm</td></tr>
<tr><td></td><td>31.4</td><td>380</td><td>33,585</td></tr>
</table>

<table>
<tr><th colspan="2">CHARACTERISTICS OF OUTPUT</th></tr>
<tr><td>Material</td><td>Chemical Composition of Exit Gas Released (% by Volume)</td></tr>
<tr><td></td><td>Refer to Attachment B, Heater Calculations</td></tr>
<tr><td colspan="2">Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.</td></tr>
</table>

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

*Standard Conditions: 70°F,14.7 psia

FORM PI-2(74-7)

TABLE 6

BOILERS AND HEATERS

Type of Device:	Regeneration Heater, HTR1	Manufacturer:	TBD
Number from flow diagram:	TBD	Model Number:	TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	100%		Average	Design Maximum 596 (scfm)
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 1006.68 (Btu/scf)	Average _____ scfm* ___% excess (vol)	Design Maximum ______ scfm * ______% excess (vol)

HEAT TRANSFER MEDIUM

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

OPERATING CHARACTERISTICS

Ave. Fire Box Temp. at max. firing rate	Fire Box Volume(ft.^{3}), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
4(ft)	110 (ft)	(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp°F	scfm
			20.9	700	7,180

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	Refer to Attachment B, Heater Calculations

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

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

*Standard Conditions: 70°F,14.7 psia

FORM PI-2(74-7)

TABLE 6

BOILERS AND HEATERS

Type of Device:	Regeneration Heater, HTR2	Manufacturer:	TBD
Number from flow diagram:	TBD	Model Number:	TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	100%		Average	Design Maximum 596 (scfm)
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 1006.68 (Btu/scf)	Average _____ scfm* ___% excess (vol)	Design Maximum ______ scfm * ______% excess (vol)

HEAT TRANSFER MEDIUM

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

OPERATING CHARACTERISTICS

Ave. Fire Box Temp. at max. firing rate	Fire Box Volume(ft.^{3}), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
4(ft)	110 (ft)	(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp°F	scfm
			20.9	700	7,180

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	Refer to Attachment B, Heater Calculations

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

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

*Standard Conditions: 70°F,14.7 psia

Table 8 – Flares

TABLE 8

FLARE SYSTEMS

Number from Flow Diagram FLR1	Manufacturer & Model No. (if available) TBD

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Max.
Refer to Attachment B, Flare Calculations		(scfm [68°F,14.7 psia])	(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])
	1.			
	2.			
	3.			
	4.			
	5.			
	6.			
	7.			
	8.			
% of time this condition occurs				

	Flow Rate (scfm [68°F, 14.7 psia])		Temp. °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	0	TBD	TBD	TBD
Fuel Added to Gas Steam	0	51.1	TBD	TBD

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [70°F & 14.7 psia]) per pilot
	Multiple	Natural Gas	4.67 (total)

For Stream Injection	Stream Pressure (psig)		Total Stream Flow	Temp. °F	Velocity (ft/sec)
	Min. Expected	Design Max.	Rate (lb/hr)		

	Number of Jet Streams	Diameter of Steam Jets (inches)	Design basis for steam injected (lb steam/lb hydrocarbon)

For Water Injection	Water Pressure (psig) Min.Expected Design Max.	Total Water Flow Rate (gpm) Min. Expected Design Max.	No. of Water Jets	Diameter of Water Jets (inches)

Flare Height (ft) 200	Flare tip inside diameter (ft) 2.5
Capital Installed Cost $ TBD	Annual Operating Cost $ TBD

Supply an assembly drawing, dimensioned and to scale, to show clearly the operation of the flare system. Show interior dimensions and features of the equipment necessary to calculate its performance. Also describe the type of ignition system and its method of operation. Provide an explanation of the control system for steam flow rate and other operating variables.

Table 29 – Reciprocating Engines

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data

Manufacturer: TBD	Model No. TBD	Serial No. TBD	Manufacture Date: TBD
Rebuilds Date: TBD	No. of Cylinders: 6	Compression Ratio: 17:1	EPN: ENG1

Application: ☐ Gas Compression ☐ Electric Generation ☐ Refrigeration ☒ Emergency/Stand by

☒ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☒ Fuel Injected

☒ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☐ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☐ Rich Burn

Ignition/Injection Timing: Fixed: Variable:

Manufacture Horsepower Rating: 500 Proposed Horsepower Rating: 500

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (°F)	Exit Velocity (FPS)
12	0.5	950	464.0

II. Fuel Data

Type of Fuel: ☐ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☒ Diesel

Fuel Consumption (BTU/bhp-hr): 7000 Heat Value: 19,676 (HHV) 18,397 (LHV)

Sulfur Content (grains/100 scf - weight %): TBD

III. Emission Factors (Before Control)

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
2.9		2.6		0.93		0.10		0.0036		0.15	

Source of Emission Factors: ☐ Manufacturer Data ☒ AP-42 ☒ Other (specify): NSPS IIII (NOx, CO, VOC, PM10)

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv

Method of Emission Control: ☐ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):______________________________

Note: *Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☐ Yes ☒ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☐ MACT ZZZZ ☒ NSPS IIII ☐ Title 30 Chapter 117 - List County: ____________________

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data

Manufacturer: TBD	Model No. TBD	Serial No. TBD	Manufacture Date: TBD
Rebuilds Date: TBD	No. of Cylinders: 6	Compression Ratio: 17:1	EPN: ENG2

Application: ☐ Gas Compression ☐ Electric Generation ☐ Refrigeration ☒ Emergency/Stand by

☒ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☒ Fuel Injected

☒ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☐ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☐ Rich Burn

Ignition/Injection Timing: Fixed: Variable:

Manufacture Horsepower Rating: 500 Proposed Horsepower Rating: 500

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (°F)	Exit Velocity (FPS)
12	0.5	950	464.0

II. Fuel Data

Type of Fuel: ☐ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☒ Diesel

Fuel Consumption (BTU/bhp-hr): 7000 Heat Value: 19,676 (HHV) 18,397 (LHV)

Sulfur Content (grains/100 scf - weight %): TBD

III. Emission Factors (Before Control)

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
2.91		2.61		0.93		0.07		0.0036		0.15	

Source of Emission Factors: ☐ Manufacturer Data ☒ AP-42 ☒ Other (specify): NSPS IIII (NOx, CO, VOC, PM10)

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv

Method of Emission Control: ☐ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):______________________________

***Note:** Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☐ Yes ☒ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☐ MACT ZZZZ ☒ NSPS IIII ☐ Title 30 Chapter 117 - List County: ____________________

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

ATTACHMENT B

DETAILED GHG EMISSION ESTIMATES

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: HEATER/BOILER/REBOILER

Facility ID: TBD **Facility:** Jefferson County NGL Fractionation Plant

Equipment Information

Source ID Number:	HOH1	Model:	Zeeco Other
Name 2:	HOH1	Serial Number:	TBD
Name 3:	Hot Oil Heater 1	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3318375	Permit Status:	TBD
Easting:	392639	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Maximum Heat Input Fuel (MMBtu/	179
Status:	Not Yet Built	Average Heat Input Fuel (MMBtu/hı	150
Ext. Comb.Type:	Heater	Fuel Heat Value (Btu/scf):	1006.68
Fuel Type:	Natural Gas	Heat Input Waste (MMBtu/hr):	N/A
Equipment Usage:	Process Heater	Waste heat Value (Btu/scf):	N/A
Configuration:	TBD		
		Potential fuel usage (MMscf/yr):	1305.28

Stack Parameters

Stack Name:	HOH1	Height (ft):	130
Stack Number:	1	Diameter (ft):	6
Emission Percent:	100.00%	Temperature (^{o}F):	380
Stack Angle (^{o}):	0	Flow (ACFM):	53,262
Raincap:	No	Velocity (ft/s):	31.4

Emission Controls: **Control Model**

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	Emission Factor EF	Units	Maximum Rating (MMBtu/hr)	Average Rating (MMBtu/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions [1, 2] (lb/hr)	(tpy)	Source of Emission Factor
CO_2	120,161	lb/MMscf	179	150	8,760	21,366.09	78,421.92	40 CFR 98 Subpart C, Table C-1
CH_4	2.27	lb/MMscf	179	150	8,760	0.40	1.48	40 CFR 98 Subpart C, Table C-2
N_2O	0.23	lb/MMscf	179	150	8,760	0.04	0.15	40 CFR 98 Subpart C, Table C-2
CO_2e						21,386.89	78,499.50	

[1] Hourly emissions estimated as follows: EF lb/MMscf x 179 MMBtu/hr / 1006.68 Btu/scf.

[2] Annual emissions estimated as follows: EF lb/MMscf x 150 MMBtu/hr / 1006.68 Btu/scf x 8,760 hr/yr / 2,000 lb/ton.

Notes **Notes Date:**

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: HEATER/BOILER/REBOILER

Facility ID:	TBD	**Facility:**	Jefferson County NGL Fractionation Plant

Equipment Information

Source ID Number:	HOH2	Model:	Zeeco Other
Name 2:	HOH2	Serial Number:	TBD
Name 3:	Hot Oil Heater 2	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3318375	Permit Status:	TBD
Easting:	392639	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Maximum Heat Input Fuel (MMBtu/	179
Status:	Not Yet Built	Average Heat Input Fuel (MMBtu/h	150
Ext. Comb.Type:	Heater	Fuel Heat Value (Btu/scf):	1006.68
Fuel Type:	Natural Gas	Heat Input Waste (MMBtu/hr):	N/A
Equipment Usage:	Process Heater	Waste heat Value (Btu/scf):	N/A
Configuration:	TBD		

Potential fuel usage (MMscf/yr): 1305.28

Stack Parameters

Stack Name:	HOH2	Height (ft):	130
Stack Number:	1	Diameter (ft):	6
Emission Percent:	100.00%	Temperature (^{o}F):	380
Stack Angle (^{o}):	0	Flow (ACFM):	53,262
Raincap:	No	Velocity (ft/s):	31.4

Control Model

Emission Controls:

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	Emission Factor		Maximum Rating	Average Rating	Hrs of Operation	Estimated Emissions		Source of Emission Factor
	EF	Units	(MMBtu/hr)	(MMBtu/hr)	(hrs/yr)	(lb/hr)	(tpy)	
CO_2	120,161	lb/MMscf	179	150	8,760	21,366.09	78,421.92	40 CFR 98 Subpart C, Table C-1
CH_4	2.27	lb/MMscf	179	150	8,760	0.40	1.48	40 CFR 98 Subpart C, Table C-2
N_2O	0.23	lb/MMscf	179	150	8,760	0.04	0.15	40 CFR 98 Subpart C, Table C-2
CO_2e						21,386.89	78,499.50	

[1] Hourly emissions estimated as follows: EF lb/MMscf x 179 MMBtu/hr / 1006.68 Btu/scf.

[2] Annual emissions estimated as follows: EF lb/MMscf x 150 MMBtu/hr / 1006.68 Btu/scf x 8,760 hr/yr / 2,000 lb/ton.

Notes Notes Date:

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: HEATER/BOILER/REBOILER

Facility ID: TBD **Facility:** Jefferson County NGL Fractionation Plant

Equipment Information

Source ID Number:	HTR1	Model:	Zeeco Other
Name 2:	HTR1	Serial Number:	TBD
Name 3:	Regeneration Heater	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3318403	Permit Status:	TBD
Easting:	392639	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (mmbtu/hr):	36
Status:	Not Yet Built	Fuel Heat Value (btu/scf):	1006.68
Ext. Comb.Type:	Heater	Heat Input Wste (mmbtu/hr):	N/A
Fuel Type:	Natural Gas	Waste heat Value (btu/scf):	N/A
Equipment Usage:	Process Heater	Pilot Heat Input (mmbtu/hr):	0.4097
Configuration:		Potential fuel usage (MMscf/yr):	214.57

Stack Parameters

		Height (ft):	110
Stack Name:	HTR1	Diameter (ft):	4
Stack Number:	10	Temperature (^oF):	700
Emission Percent:	100.00%	Flow (ACFM):	15,725
Stack Angle (^{o}):	0	Velocity (ft/s):	20.9
Raincap:	No		

Potential burner operation:	6,000	hr/yr
Potential pilot operation:	2,760	hr/yr

Potential Emissions - Burner Operation

Pollutant	Emission Factor		Nominal Rating	Hrs of Operation	Estimated Emissions [1, 2]		Source of Emission Factor
	EF	Units	(MMBtu/hr)	(hrs/yr)	(lb/hr)	(tpy)	
CO_2	120,161	lb/MMscf	36	6,000	4,297.09	12,891.27	40 CFR 98 Subpart C, Table C-1
CH_4	2.27	lb/MMscf	36	6,000	0.08	0.24	40 CFR 98 Subpart C, Table C-2
N_2O	0.23	lb/MMscf	36	6,000	0.008	0.02	40 CFR 98 Subpart C, Table C-2
CO_2e					4,301.25	12,902.51	

[1] Hourly emissions estimated as follows: EF lb/MMscf x 36 MMBtu/hr / 1006.68 Btu/scf.

[2] Annual emissions estimated as follows: EF lb/MMscf x 36 MMBtu/hr / 1006.68 Btu/scf x 6,000 hr/yr / 2,000 lb/ton.

Potential Emissions - Pilot Operation

Pollutant	Emission Factor		Nominal Rating	Hrs of Operation	Estimated Emissions [1, 2]		Source of Emission Factor
	EF	Units	(MMBtu/hr)	(hrs/yr)	(lb/hr)	(tpy)	
CO_2	120,161	lb/MMscf	0.4097	2,760	48.90	67.49	40 CFR 98 Subpart C, Table C-1
CH_4	2.27	lb/MMscf	0.4097	2,760	1.0E-03	1.0E-03	40 CFR 98 Subpart C, Table C-2
N_2O	0.23	lb/MMscf	0.4097	2,760	1.0E-04	1.0E-04	40 CFR 98 Subpart C, Table C-2
CO_2e					48.95	67.54	

[1] Hourly emissions estimated as follows: EF lb/MMscf x 0.4097 MMBtu/hr / 1006.68 Btu/scf.

[2] Annual emissions estimated as follows: EF lb/MMscf x 0.4097 MMBtu/hr / 1006.68 Btu/scf x 2,760 hr/yr / 2,000 lb/ton.

Potential Emissions - TOTAL

Pollutant	Estimated Emissions	
	(lb/hr)	(tpy)
CO_2	4,297.09	12,958.76
CH_4	0.08	0.24
N_2O	0.008	0.02
CO_2e	4,301.25	12,970.05

Notes **Notes Date:**

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: HEATER/BOILER/REBOILER

Facility ID: TBD **Facility:** Jefferson County NGL Fractionation Plant

Equipment Information

Source ID Number:	HTR2	Model:	Zeeco Other
Name 2:	HTR2	Serial Number:	TBD
Name 3:	Regeneration Heater 2	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3318171	Permit Status:	TBD
Easting:	392641	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (mmbtu/hr):	36
Status:	Not Yet Built	Fuel Heat Value (btu/scf):	1006.68
Ext. Comb.Type:	Heater	Heat Input Wste (mmbtu/hr):	N/A
Fuel Type:	Natural Gas	Waste heat Value (btu/scf):	N/A
Equipment Usage:	Process Heater	Pilot Heat Input (mmbtu/hr):	0.4097
Configuration:		Potential fuel usage (MMscf/yr):	214.57

Stack Parameters

		Height (ft):	110
Stack Name:	HTR2	Diameter (ft):	4
Stack Number:	10	Temperature (^{o}F):	700
Emission Percent:	100.00%	Flow (ACFM):	15,725
Stack Angle (^{o}):	0	Velocity (ft/s):	20.9
Raincap:	No		

Potential burner operation:	6,000	hr/yr
Potential pilot operation:	2,760	hr/yr

Potential Emissions - Burner Operation

Pollutant	Emission Factor		Nominal Rating	Hrs of Operation	Estimated Emissions [1, 2]		Source of Emission Factor
	EF	Units	(MMBtu/hr)	(hrs/yr)	(lb/hr)	(tpy)	
CO_2	120,161	lb/MMscf	36	6,000	4,297.09	12,891.27	40 CFR 98 Subpart C, Table C-1
CH_4	2.27	lb/MMscf	36	6,000	0.08	0.24	40 CFR 98 Subpart C, Table C-2
N_2O	0.23	lb/MMscf	36	6,000	0.008	0.02	40 CFR 98 Subpart C, Table C-2
CO_2e					4,301.25	12,902.51	

[1] Hourly emissions estimated as follows: EF lb/MMscf x 36 MMBtu/hr / 1006.68 Btu/scf.

[2] Annual emissions estimated as follows: EF lb/MMscf x 36 MMBtu/hr / 1006.68 Btu/scf x 6,000 hr/yr / 2,000 lb/ton.

Potential Emissions - Pilot Operation

Pollutant	Emission Factor		Nominal Rating	Hrs of Operation	Estimated Emissions [1, 2]		Source of Emission Factor
	EF	Units	(MMBtu/hr)	(hrs/yr)	(lb/hr)	(tpy)	
CO_2	120,161	lb/MMscf	0.4097	2,760	48.90	67.49	40 CFR 98 Subpart C, Table C-1
CH_4	2.27	lb/MMscf	0.4097	2,760	1.0E-03	1.0E-03	40 CFR 98 Subpart C, Table C-2
N_2O	0.23	lb/MMscf	0.4097	2,760	1.0E-04	1.0E-04	40 CFR 98 Subpart C, Table C-2
CO_2e					48.95	67.54	

[1] Hourly emissions estimated as follows: EF lb/MMscf x 0.4097 MMBtu/hr / 1006.68 Btu/scf.

[2] Annual emissions estimated as follows: EF lb/MMscf x 0.4097 MMBtu/hr / 1006.68 Btu/scf x 2,760 hr/yr / 2,000 lb/ton.

Potential Emissions - TOTAL

Pollutant	Estimated Emissions	
	(lb/hr)	(tpy)
CO_2	4,297.09	12,958.76
CH_4	0.08	0.24
N_2O	0.008	0.02
CO_2e	4,301.25	12,970.05

Notes **Notes Date:**

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: FIREWATER PUMP ENGINE

Facility ID:	TBD	**Facility:**	Jefferson County NGL Fractionation Plant

Equipment Information

Source ID Number:	ENG1	Model:	TBD
Name 2:	500 hp Diesel Firewater Pump Engine	Serial Number:	
Name 3:		Service Date:	
Coordinates:	UTM	Manufacture Date:	
Northing:	3318176	Permit Status:	
Easting:	392603	SCC:	
Source Location Zone:	15		

Ownership:	DCP owned	Horsepower (bhp):	500	
Status:	Not Yet Built	Heat Rate (MMBtu/hr):	3.50	
Service Type:	Other	Rotations per Minute (rpm):	TBD	
Configuration:	Diesel	Fuel Consumption (btu/hp-hr):	7000	AP-42, Table 3-3.1 (Footnote A)
Fuel Type:	Diesel	Fuel Heat Value (MMBtu/gallon)	0.138	
Oil Type:	Unknown	Oil Usage (gal/month):	TBD	
Compression Ratio:		Cylinders:	6	
Ignition Timing:		Potential fuel usage (gallons/yr):	2536.23	
Operating Range (%):				

Stack Parameters

Stack Name:	ENG1	Height (ft):	12
Stack Number:	1	Diameter (ft):	0.67
Emission Percent:	100.00%	Temperature (^{o}F):	787
Stack Angle (^{o}):	0	Flow (ACFM):	2519
Raincap:	No	Velocity (ft/s):	119.1

	Control Model
Emission Controls:	

Potential operation: 100 hr/yr

Potential Emissions

Pollutant	Emission Factor		Nominal Rating		Hrs of Operation	Estimated Emissions		Source of Emission Factor
	EF	Units	(hp)	(MMBtu/hr)	(hrs/yr)	(lb/hr)	(tpy)	
CO_2	163.05	lb/MMBtu	500	3.50	100	570.68	28.53	40 CFR 98 Subpart C, Table C-1
CH_4	0.007	lb/MMBtu	500	3.50	100	0.02	1.0E-03	40 CFR 98 Subpart C, Table C-2
N_2O	0.001	lb/MMBtu	500	3.50	100	4.0E-03	2.0E-04	40 CFR 98 Subpart C, Table C-2
CO_2e						572.34	28.62	

Notes **Notes Date:**

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: FIREWATER PUMP ENGINE

Facility ID:	TBD	**Facility:**	Jefferson County NGL Fractionation Plant

Equipment Information

Source ID Number:	ENG2	Model:	TBD
Name 2:	500 hp Diesel Emergency Generator Engine	Serial Number:	
Name 3:		Service Date:	
Coordinates:	UTM	Manufacture Date:	
Northing:	3318247	Permit Status:	
Easting:	392901	SCC:	
Source Location Zone:	15		

Ownership:	DCP owned	Horsepower (bhp):	500	
Status:	Not Yet Built	Heat Rate (MMBtu/hr):	3.50	
Service Type:	Other	Rotations per Minute (rpm):	TBD	
Configuration:	Diesel	Fuel Consumption (btu/hp-hr):	7000	AP-42, Table 3-3.1 (Footnote A)
Fuel Type:	Diesel	Fuel Heat Value (MMBtu/gallon)	0.138	
Oil Type:	Unknown	Oil Usage (gal/month):	TBD	
Compression Ratio:		Cylinders:	6	
Ignition Timing:		Potential fuel usage (gallons/yr):	2536.23	
Operating Range (%):				

Stack Parameters

Stack Name:	ENG2	Height (ft):	12
Stack Number:	1	Diameter (ft):	0.33
Emission Percent:	100.00%	Temperature (^{o}F):	1011
Stack Angle (^{o}):	0	Flow (ACFM):	2345
Raincap:	No	Velocity (ft/s):	457.0

	Control Model
Emission Controls:	

Potential operation: 100 hr/yr

Potential Emissions

Pollutant	Emission Factor		Nominal Rating		Hrs of Operation	Estimated Emissions		Source of Emission Factor
	EF	Units	(hp)	(MMBtu/hr)	(hrs/yr)	(lb/hr)	(tpy)	
CO_2	163.05	lb/MMBtu	500	3.50	100	570.68	28.53	40 CFR 98 Subpart C, Table C-1
CH_4	0.007	lb/MMBtu	500	3.50	100	0.02	1.0E-03	40 CFR 98 Subpart C, Table C-2
N_2O	0.001	lb/MMBtu	500	3.50	100	4.0E-03	2.0E-04	40 CFR 98 Subpart C, Table C-2
CO_2e						572.34	28.62	

Notes **Notes Date:**

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: FLARE

Facility ID: TBD **Facility:** Jefferson County NGL Fractionation Plant

Equipment Information

Source ID Number:	FLR1	SCC:	31000205
Equipment ID:	FLR1	Coordinates:	UTM
Source Description:	Air-assisted Flare	Northing:	3318659
Equipment Usage:	VOC Flare	Easting:	392608
Equipment Make:		Source Location Zone:	15
Equipment Model:			
Serial Number:	N/A		
Date in Service:		Potential Operation:	8,760 hr/yr
Equipment Configuration:	Smokeless, air-assisted		
Number of Pilots:	Multiple	Stack ID:	FLARE-1
Continuous Fuel Flow to Pilots:	280 (scf/hr)	Stack Height:	200 ft. agl
		Effective Stack Diameter:	4.5 ft
		Actual Stack Diameter:	2.5 ft
		Exit Velocity:	65.60 ft/sec
		Exit Temperature:	1832 °F
		Volume Flow Rate:	19321 ft^3/min

Potential Emissions

Pollutant	Supplemental gas Estimated Emissions		Intermittent Normal Vents Estimated Emissions		MSS Estimated Emissions		Total Estimated Emissions	
	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)		
CO_2	402.06	1761.02	46.65	204.49	125,003.80	5,249.91	125,452.51	7,215.42
CH_4	0.01	0.03	1.0E-03	3.0E-03	0.92	0.88	0.93	0.91
N_2O	8.0E-04	3.4E-03	3.0E-05	1.3E-04	0.05	7.13	0.05	7.14
CO_2e	402.48	1762.76	46.68	204.59	125,038.62	7,479.94	125,487.78	9,447.29

Start Date: **Version:** **1.0** **Equip_Int_ID:**

Emissions Calculation: FLARE

Facility ID: TBD

Facility: Jefferson County NGL Fractionation Plant

Equipment Information

Source ID Number: FLR1
Name 2: FLR1
Name 3: VOC Flare
Coordinates: UTM
Northing: 3318659
Easting: 392608
Source Location Zone: 15

Model:
Serial Number: TBD
Service Date: TBD
Manufacture Date: TBD
Permit Status: TBD
SCC: TBD

Pilot Fuel (scf/hr): 280
Header Sweep Gas (scf/hr): 3066
Heat Input Fuel (MMBtu/hr): 3.368
Fuel Heat Value (Btu/scf): 1006.68

Ownership: DCP owned
Status: Not Yet Built
Ext. Comb.Type:
Fuel Type: Natural Gas
Equipment Usage:
Configuration:

Potential fuel usage (scf/hr): 3346.00
Potential fuel usage (MMscf/yr): 29.31

Stack Parameters

Stack Name: FLR1
Stack Number:
Emission Percent:
Stack Angle (o):
Raincap:

Height (ft): 200
Effective Diameter (ft): 4.5
Actual Diameter (ft) 2.5
Temperature (°F) 1832
Volume Flow Rate (ft 19321
Exit Velocity (ft/sec) 65.6

Control Model

Emission Controls:

Potential operation: 8760 hr/yr

Potential Emissions: Products of Combustion: fuel

Pollutant	Emission Factor		Nominal Rating (MMscf/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions		Source of Emission Factor
	EF	Units			(lb/hr)	(tpy)	
CO_2	120161	lb/MMscf	3.346E-03	8,760	402.06	1,761.02	40 CFR 98 Subpart C, Table C-1
CH_4	2.27	lb/MMscf	3.346E-03	8,760	8.0E-03	0.03	40 CFR 98 Subpart C, Table C-2
N_2O	0.23	lb/MMscf	3.346E-03	8,760	8.0E-04	3.4E-03	40 CFR 98 Subpart C, Table C-2
CO_2e					402.48	1,762.76	

Notes **Notes Date:**

Jefferson County NGL Fractionation Plant

Pump Seal Leaks and Analyzer Sample Purge to Flare (EPN: FLR1)

Control Efficiency 98.0%

SourceDescription	Compound	Amount Released[1]				Density	Uncontrolled MSS Emissions	Molecular Weight	Moles of Hydrocarbon		Number of Carbon Moles	Moles of CO_2 from Combustion		Controlled Flare Emissions	
		per Hour[2]	Units	(lb/hr)	(lb/yr)	(lb/gal)	(lb/yr)	(lb/lb-mol)	(lb-mol/hr)	(lb-mol/yr)	mol-C/lb-mo	(lb-mol/hr)	(lb-mol/yr)	(lb/hr)	(tpy)
Ethane Injection Pumps (4) Seal Leaks	Ethane	0.11464	lb	0.11464	1,004.25	2.63	1,004.25	30.07	3.8E-03	33.40	2	0.01	66.79	2.0E-03	0.01
Deethanizer Reflux Pumps (4) Seal Leaks	Ethane	0.11464	lb	0.11464	1,004.25	2.63	1,004.25	30.07	3.8E-03	33.40	2	0.01	66.79	2.0E-03	0.01
Ethane Booster Pumps (4) Seal Leaks	Ethane	0.11464	lb	0.11464	1,004.25	2.63	1,004.25	30.07	3.8E-03	33.40	2	0.01	66.79	2.0E-03	0.01
Debutanizer Reflux Pumps (4) Seal Leaks	Mixed Butanes	0.11464	lb	0.11464	1,004.25	4.78	1,004.25	58.12	2.0E-03	17.28	4	0.01	69.12	2.0E-03	0.01
Deisobutanizer KO Drum Pump (2) Seal Leaks	Mixed Butanes	0.05732	lb	0.05732	502.12	4.78	502.12	58.12	9.9E-04	8.64	4	3.9E-03	34.56	1.0E-03	0.01
Deisobutanizer Bottoms Booster Pumps (4) Seal Leaks	Mixed Butanes	0.11464	lb	0.11464	1,004.25	4.78	1,004.25	58.12	2.0E-03	17.28	4	0.01	69.12	2.0E-03	0.01
Propane Injection Pumps (4) Seal Leaks	Propane	0.11464	lb	0.11464	1,004.25	4.12	1,004.25	44.10	2.6E-03	22.77	3	0.01	68.32	2.0E-03	0.01
Isobutane Injection Pumps (4) Seal Leaks	Mixed Butanes	0.11464	lb	0.11464	1,004.25	4.78	1,004.25	58.12	2.0E-03	17.28	4	0.01	69.12	2.0E-03	0.01
n-Butane Injection Pumps (4) Seal Leaks	Mixed Butanes	0.11464	lb	0.11464	1,004.25	4.78	1,004.25	58.12	2.0E-03	17.28	4	0.01	69.12	2.0E-03	0.01
Refrigerant Suction KO Drum Pumps (2) Seal Leaks	Propylene	0.05732	lb	0.05732	502.12	5.08	502.12	58.12	9.9E-04	8.64	4	0.00	34.56	1.0E-03	0.01
Feed to Deethanizer Analyzer Sample Purge (2)	Nitrogen	8.2E-06	lb-mol	0.00023	2.02	-	2.02	28.01	8.2E-06	0.07	0	0	0	2.3E-04	1.0E-03
	Carbon Dioxide	6.2E-05	lb-mol	0.00271	23.77	-	23.77	44.01	6.2E-05	0.54	-	-	-	2.7E-03	0.01
	Methane	5.0E-04	lb-mol	0.00804	70.47	-	70.47	16.04	5.0E-04	4.39	1	0.00	4.39	2.0E-04	1.0E-03
	Ethane	0.02	lb-mol	0.70135	6,143.84	-	6,143.84	30.07	2.3E-02	204.32	2	0.05	408.64	1.4E-02	0.06
	Propane	0.01	lb-mol	0.58046	5,084.83	-	5,084.83	44.10	1.3E-02	115.30	3	0.04	345.91	1.2E-02	0.05
	Isobutane	2.5E-03	lb-mol	0.14526	1,272.47	-	1,272.47	58.12	2.5E-03	21.89	4	0.01	87.58	3.0E-03	0.01
	n-Butane	4.4E-03	lb-mol	0.25850	2,264.49	-	2,264.49	58.12	4.4E-03	38.96	4	0.02	155.85	5.0E-03	0.02
	Isopentane	1.3E-03	lb-mol	0.09224	808.00	-	808.00	72.15	1.3E-03	11.20	5	0.01	55.99	2.0E-03	0.01
	Pentane	1.1E-03	lb-mol	0.07978	698.88	-	698.88	72.15	1.1E-03	9.69	5	0.01	48.43	2.0E-03	0.01
	Cyclopentane	9.0E-05	lb-mol	0.00634	55.53	-	55.53	70.10	9.0E-05	0.79	5	0.00	3.96	1.0E-04	1.0E-03
	Hexane*	6.6E-04	lb-mol	0.05663	496.07	-	496.07	86.10	6.6E-04	5.76	6	0.00	34.57	1.0E-03	0.01
	Methylcyclopentane	1.8E-04	lb-mol	0.01557	136.38	-	136.38	84.16	1.8E-04	1.62	6	0.00	9.72	3.0E-04	1.0E-03
	Benzene*	9.5E-05	lb-mol	0.00738	64.69	-	64.69	78.11	9.5E-05	0.83	6	0.00	4.97	1.0E-04	1.0E-03
	Cyclohexane	1.2E-04	lb-mol	0.01003	87.89	-	87.89	84.16	1.2E-04	1.04	6	0.00	6.27	2.0E-04	1.0E-03
	Methyl Cyclohexane	1.6E-04	lb-mol	0.01615	141.43	-	141.43	98.19	1.6E-04	1.44	7	0.00	10.08	3.0E-04	1.0E-03
	Toluene*	7.8E-05	lb-mol	0.00720	63.04	-	63.04	92.14	7.8E-05	0.68	7	0.00	4.79	1.0E-04	1.0E-03
	Mixed Xylenes*	3.3E-05	lb-mol	0.00349	30.58	-	30.58	106.16	3.3E-05	0.29	8	0.00	2.30	1.0E-04	3.0E-04
	Carbon Disulfide*	4.1E-07	lb-mol	0.00003	0.27	-	0.27	76.14	4.1E-07	0.00	1	0.00	0.00	1.0E-06	3.0E-06
Ethane Product Analyzer Sample Purge (2)	Nitrogen	4.1E-07	lb-mol	0.00001	0.10	-	0.10	28.01	4.1E-07	0.00	0	0.00	0.00	1.2E-05	5.0E-05
	Carbon Dioxide	2.5E-05	lb-mol	0.00109	9.51	-	9.51	44.01	2.5E-05	0.22	-	-	-	1.1E-03	4.8E-03
	Methane	1.2E-03	lb-mol	0.01938	169.81	-	169.81	16.04	1.2E-03	10.59	1	0.00	10.59	3.9E-04	1.7E-03
	Ethane	0.04	lb-mol	1.21185	10,615.82	-	10,615.82	30.07	4.0E-02	353.04	2	0.08	706.07	2.4E-02	0.11
	Propane	2.0E-04	lb-mol	0.00870	76.22	-	76.22	44.10	2.0E-04	1.73	3	0.00	5.19	8.7E-03	0.04
Deethanizer Bottoms Analyzer Sample Purge (2)	Ethane	1.2E-04	lb-mol	0.00371	32.48	-	32.48	30.07	1.2E-04	1.08	2	0.00	2.16	3.7E-03	0.02
	Propane	0.02	lb-mol	1.03511	9,067.58	-	9,067.58	44.10	2.3E-02	205.61	3	0.07	616.84	2.1E-02	0.09
	Isobutane	4.3E-03	lb-mol	0.24990	2,189.14	-	2,189.14	58.12	4.3E-03	37.67	4	0.02	150.66	5.0E-03	0.02
	n-Butane	7.6E-03	lb-mol	0.44462	3,894.83	-	3,894.83	58.12	7.6E-03	67.01	4	0.03	268.05	9.0E-03	0.04
	Isopentane	2.2E-03	lb-mol	0.15838	1,387.38	-	1,387.38	72.15	2.2E-03	19.23	5	0.01	96.15	3.0E-03	0.01
	Pentane	1.9E-03	lb-mol	0.13732	1,202.91	-	1,202.91	72.15	1.9E-03	16.67	5	0.01	83.36	3.0E-03	0.01
	Cyclopentane	1.5E-04	lb-mol	0.01066	93.40	-	93.40	70.10	1.5E-04	1.33	5	0.00	6.66	2.0E-04	9.3E-04
	Hexane*	1.1E-03	lb-mol	0.09733	852.61	-	852.61	86.10	1.1E-03	9.90	6	0.01	59.42	2.0E-03	0.01
	Methylcyclopentane	3.2E-04	lb-mol	0.02698	236.38	-	236.38	84.16	3.2E-04	2.81	6	0.00	16.85	1.0E-03	2.0E-03
	Benzene*	1.6E-04	lb-mol	0.01252	109.70	-	109.70	78.11	1.6E-04	1.40	6	0.00	8.43	3.0E-04	1.0E-03
	Cyclohexane	2.0E-04	lb-mol	0.01695	148.50	-	148.50	84.16	2.0E-04	1.76	6	0.00	10.59	3.0E-04	1.0E-03
	Methyl Cyclohexane	2.8E-04	lb-mol	0.02785	243.97	-	243.97	98.19	2.8E-04	2.48	7	0.00	17.39	1.0E-03	2.0E-03
	Toluene*	1.4E-04	lb-mol	0.01250	109.49	-	109.49	92.14	1.4E-04	1.19	7	0.00	8.32	2.0E-04	1.0E-03
	Mixed Xylenes*	5.8E-05	lb-mol	0.00611	53.52	-	53.52	106.16	5.8E-05	0.50	8	0.00	4.03	1.0E-04	1.0E-03
	Mercaptans	4.1E-06	lb-mol	0.00026	2.24	-	2.24	62.13	4.1E-06	0.04	2	0.00	0.07	1.0E-05	2.2E-05
	Carbon Disulfide*	8.2E-07	lb-mol	0.00006	0.55	-	0.55	76.14	8.2E-07	0.01	1	0.00	0.01	1.0E-06	5.0E-06
	Dimethyl Sulfide	4.1E-07	lb-mol	0.00003	0.22	-	0.22	62.13	4.1E-07	0.00	2	0.00	0.01	1.0E-06	2.0E-06
Depropanizer Product Analyzer Sample Purge (2)	Ethane	2.1E-04	lb-mol	0.00643	56.31	-	56.31	30.07	2.1E-04	1.87	2	0.00	3.74	1.0E-04	1.0E-03
	Propane	0.04	lb-mol	1.79577	15,730.91	-	15,730.91	44.10	4.1E-02	356.71	3	0.12	1070.13	3.6E-02	0.16
	Isobutane	1.7E-04	lb-mol	0.01003	87.90	-	87.90	58.12	1.7E-04	1.51	4	0.00	6.05	2.0E-04	1.0E-03

Jefferson County NGL Fractionation Plant

Pump Seal Leaks and Analyzer Sample Purge to Flare (EPN: FLR1)

Control Efficiency 98.0%

SourceDescription	Compound	Amount Released[1]				Density	Uncontrolled MSS Emissions	Molecular Weight	Moles of Hydrocarbon		Number of Carbon Moles	Moles of CO_2 from Combustion		Controlled Flare Emissions	
		per Hour[2]	Units	(lb/hr)	(lb/yr)	(lb/gal)	(lb/yr)	(lb/lb-mol)	(lb-mol/hr)	(lb-mol/yr)	mol-C/lb-mo	(lb-mol/hr)	(lb-mol/yr)	(lb/hr)	(tpy)
Debutanizer Overheads Analyzer Sample Purge (2)	Propane	1.4E-04	lb-mol	0.00634	55.58	-	55.58	44.10	1.4E-04	1.26	3	0.00	3.78	1.0E-04	1.0E-03
	Isobutane	0.02	lb-mol	0.87991	7,708.05	-	7,708.05	58.12	1.5E-02	132.62	4	0.06	530.49	1.8E-02	0.08
	n-Butane	0.03	lb-mol	1.52999	13,402.75	-	13,402.75	58.12	2.6E-02	230.60	4	0.11	922.42	3.1E-02	0.13
	Isopentane	1.4E-04	lb-mol	0.01008	88.33	-	88.33	72.15	1.4E-04	1.22	5	0.00	6.12	2.0E-04	1.0E-03
	Pentane	4.1E-06	lb-mol	0.00030	2.60	-	2.60	72.15	4.1E-06	0.04	5	0.00	0.18	1.0E-05	3.0E-05
	Mercaptans	8.2E-06	lb-mol	0.00051	4.47	-	4.47	62.13	8.2E-06	0.07	2	0.00	0.14	1.0E-05	4.0E-05
	Carbon Disulfide*	1.6E-06	lb-mol	0.00013	1.10	-	1.10	76.14	1.6E-06	0.01	1	0.00	0.01	3.0E-06	1.0E-05
Deisobutanizer Overheads Analyzer Sample Purge (2)	Propane	3.9E-04	lb-mol	0.01722	150.86	-	150.86	44.10	3.9E-04	3.42	3	0.00	10.26	3.0E-04	2.0E-03
	Isobutane	0.04	lb-mol	2.32892	20,401.31	-	20,401.31	58.12	4.0E-02	351.02	4	0.16	1404.08	4.7E-02	0.20
	n-Butane	6.4E-04	lb-mol	0.03703	324.40	-	324.40	58.12	6.4E-04	5.58	4	0.00	22.33	1.0E-03	3.0E-03
	Mercaptans	8.2E-06	lb-mol	0.00051	4.47	-	4.47	62.13	8.2E-06	0.07	2	0.00	0.14	1.0E-05	4.0E-05
n-Butane Product Analyzer Sample Purge (2)	Isobutane	6.0E-04	lb-mol	0.03464	303.47	-	303.47	58.12	6.0E-04	5.22	4	0.00	20.89	1.0E-03	3.0E-03
	n-Butane	0.04	lb-mol	2.34349	20,528.97	-	20,528.97	58.12	4.0E-02	353.22	4	0.16	1412.87	4.7E-02	0.21
	Isopentane	2.1E-04	lb-mol	0.01542	135.10	-	135.10	72.15	2.1E-04	1.87	5	0.00	9.36	3.0E-04	1.0E-03
	Pentane	8.2E-06	lb-mol	0.00059	5.20	-	5.20	72.15	8.2E-06	0.07	5	0.00	0.36	1.0E-05	1.0E-04
	Mercaptans	4.1E-06	lb-mol	0.00026	2.24	-	2.24	62.13	4.1E-06	0.04	2	0.00	0.07	1.0E-05	2.0E-05
	Carbon Disulfide*	2.5E-06	lb-mol	0.00019	1.65	-	1.65	76.14	2.5E-06	0.02	1	0.00	0.02	4.0E-06	2.0E-05
TOTAL				**15.52**	**135,974.90**		**135,974.90**		**0.32**	**2,808.94**	**-**	**1.06**	**9,292.04**	**0.33**	**1.43**

[1] Annual rates conservatively assume the hourly vent rate is continuous for the purpose of estimating annual emissions. However, these vents are intermittent and will likely not emit at the hourly rate every hour of the year.

[2] The leak rate for each pump seal is assumed to be equal to the leak rate (0.02866 lb/hr/source) for pumps in light liquid service at Oil and Gas Production Operations in the TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. The individual leak rate is multiplied by the number of pumps to estimate the total leak rate for all pumps.

Vent Gas HHV[3] (MMBtu/scf): 0.001235

Potential operation: 8760 hr/yr

Potential Emissions: Products of Combustion Pump Seal Leaks and Sample Purges

Pollutant	Emission Factor		Estimated Emissions [1, 4]		Source of Emission Factor
	EF	Units	(lb/hr)	(tpy)	
CO_2	1.06	lb-mol/hr	46.65	204.49	40 CFR 98 Subpart W [1]
CH_4	0.00004	lb-mol/hr	1.0E-03	3.0E-03	40 CFR 98 Subpart W [2]
N_2O	0.0002	lb/MMBtu	3.0E-05	1.3E-04	40 CFR 98 Subpart W [3]
CO_2e	-	-	46.68	204.59	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO_2. Emission factor is multiplied by molecular weight of CO_2 (44.01 lb/lb-mol) to estimate emissions.

[2] Assumes 98% destruction of methane. Remaining 2% of methane in waste gas is emitted as methane.

[3] Uses the vent gas heating value of 1.235 x 10^{-3} MMBtu/scf and 1 x 10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

[4] Represents emissions for two process trains.

Jefferson County NGL Fractionation Plant

Speciated MSS Waste Gas Streams Sent to Flare (EPN: FLR1)

Control Efficiency 98.0%

MSS Event Description	Compound	MSS Frequency	Frequency Counter	Amount Released				Density	Uncontrolled MSS Emissions	Molecular Weight	Moles of Hydrocarbon		Number of Carbon Moles	Moles of CO_2 from Combustion		Controlled Flare Emissions	
			(Events/yr)	per Event	Units	(lb/event)	(lb/yr)	(lb/gal)	(lb/yr)	(lb/lb-mol)	(lb-mol/hr)	(lb-mol/yr)	(mol-C/lb-mol)	(lb-mol/hr)	(lb-mol/yr)	(lb/event)	(tpy)
Butane Prover	Butane	Monthly	24	10.00	gal	47.80	1,147.20	4.78	1,147.20	58.12	0.82	19.74	4	3.29	78.95	0.96	0.01
Ethane Product Strainer	Ethane	Monthly	24	2.00	bbl	220.92	5,302.08	2.63	5,302.08	30.07	7.35	176.32	2	14.69	352.65	4.42	0.05
Deethanizer Reflux Pump	Ethane	Quarterly	8	1.00	bbl	110.46	883.68	2.63	883.68	30.07	3.67	29.39	2	7.35	58.77	2.21	8.8E-03
Deethanizer Reflux Pump	Ethane	Quarterly	8	1.00	bbl	110.46	883.68	2.63	883.68	30.07	3.67	29.39	2	7.35	58.77	2.21	8.8E-03
Ethane Booster Pump	Ethane	Quarterly	8	1.00	bbl	110.46	883.68	2.63	883.68	30.07	3.67	29.39	2	7.35	58.77	2.21	8.8E-03
Ethane Booster Pump	Ethane	Quarterly	8	1.00	bbl	110.46	883.68	2.63	883.68	30.07	3.67	29.39	2	7.35	58.77	2.21	8.8E-03
Ethane Injection Pump	Ethane	Weekly	104	1.00	bbl	110.46	11,487.84	2.63	11,487.84	30.07	3.67	382.04	2	7.35	764.07	2.21	0.11
Ethane Injection Pump	Ethane	Weekly	104	1.00	bbl	110.46	11,487.84	2.63	11,487.84	30.07	3.67	382.04	2	7.35	764.07	2.21	0.11
Ethane Prover	Ethane	Monthly	24	2.00	bbl	220.92	5,302.08	2.63	5,302.08	30.07	7.35	176.32	2	14.69	352.65	4.42	0.05
Mixed Butane Product Strainer	Mixed Butanes	Monthly	24	2.00	bbl	401.52	9,636.48	4.78	9,636.48	58.12	6.91	165.80	4	27.63	663.21	8.03	0.10
Debutanizer Reflux Pump	Mixed Butanes	Quarterly	8	1.00	bbl	200.76	1,606.08	4.78	1,606.08	58.12	3.45	27.63	4	13.82	110.54	4.02	0.02
Debutanizer Reflux Pump	Mixed Butanes	Quarterly	8	1.00	bbl	200.76	1,606.08	4.78	1,606.08	58.12	3.45	27.63	4	13.82	110.54	4.02	0.02
Butane Product Pumps	Mixed Butanes	Quarterly	8	1.00	bbl	200.76	1,606.08	4.78	1,606.08	58.12	3.45	27.63	4	13.82	110.54	4.02	0.02
Butane Product Pumps	Mixed Butanes	Quarterly	8	1.00	bbl	200.76	1,606.08	4.78	1,606.08	58.12	3.45	27.63	4	13.82	110.54	4.02	0.02
Gasoline Product Strainer	Natural Gasoline	Monthly	24	2.00	bbl	336.00	8,064.00	4.00	8,064.00	72.15	4.66	111.77	5	23.28	558.84	6.72	0.08
Debutanizer Bottoms Pump	Natural Gasoline	Quarterly	8	1.00	bbl	168.00	1,344.00	4.00	1,344.00	72.15	2.33	18.63	5	11.64	93.14	3.36	0.01
Debutanizer Bottoms Pump	Natural Gasoline	Quarterly	8	1.00	bbl	168.00	1,344.00	4.00	1,344.00	72.15	2.33	18.63	5	11.64	93.14	3.36	0.01
Pentane Prover	Pentane	Monthly	24	10.00	gal	40.00	960.00	4.00	960.00	72.15	0.55	13.31	5	2.77	66.53	0.80	9.6E-03
Depropanizer Heat Pump Compressor	Propane	Monthly	24	2.00	bbl	346.08	8,305.92	4.12	8,305.92	44.10	7.85	188.34	3	23.54	565.03	6.92	0.08
Propane Product Strainer	Propane	Monthly	24	2.00	bbl	346.08	8,305.92	4.12	8,305.92	44.10	7.85	188.34	3	23.54	565.03	6.92	0.08
Propane Injection Pump	Propane	Quarterly	8	1.00	bbl	173.04	1,384.32	4.12	1,384.32	44.10	3.92	31.39	3	11.77	94.17	3.46	0.01
Propane Injection Pump	Propane	Quarterly	8	1.00	bbl	173.04	1,384.32	4.12	1,384.32	44.10	3.92	31.39	3	11.77	94.17	3.46	0.01
Flare KO Drum Pump	Propane	Quarterly	8	1.00	bbl	173.04	1,384.32	4.12	1,384.32	44.10	3.92	31.39	3	11.77	94.17	3.46	0.01
Propane Prover	Propane	Monthly	24	5.00	bbl	865.20	20,764.80	4.12	20,764.80	44.10	19.62	470.86	3	58.86	1412.57	17.30	0.21
Regenerant Pump	Y-Grade	Quarterly	8	1.00	bbl	245.28	1,962.24	5.84	1,962.24	72.15	3.40	27.20	5	17.00	135.98	4.91	0.02
Regenerant Pump	Y-Grade	Quarterly	8	1.00	bbl	245.28	1,962.24	5.84	1,962.24	72.15	3.40	27.20	5	17.00	135.98	4.91	0.02
Y-Grade Feed Prefilter	Y-Grade	Semiannual	8	28.00	bbl	6,867.84	54,942.72	5.84	54,942.72	72.15	95.19	761.51	5	475.94	3807.53	137.36	0.55
Y-Grade Feed Prefilter	Y-Grade	Semiannual	8	28.00	bbl	6,867.84	54,942.72	5.84	54,942.72	72.15	95.19	761.51	5	475.94	3807.53	137.36	0.55
Feed Coalescer	Y-Grade	Semiannual	4	102.30	bbl	25,092.14	100,368.58	5.84	100,368.58	72.15	347.78	1391.11	5	1738.89	6955.55	501.84	1.00
Stage 1 Amine Coalescer	Y-Grade	Semiannual	4	160.50	bbl	39,367.44	157,469.76	5.84	157,469.76	72.15	545.63	2182.53	5	2728.17	10912.67	787.35	1.57
Stage 2 Amine Coalescer	Y-Grade	Semiannual	4	160.50	bbl	39,367.44	157,469.76	5.84	157,469.76	72.15	545.63	2182.53	5	2728.17	10912.67	787.35	1.57
Feed Dehydrator	Y-Grade	Semiannual	4	167.10	bbl	40,986.29	163,945.15	5.84	163,945.15	72.15	568.07	2272.28	5	2840.35	11361.41	819.73	1.64
Feed Dehydrator	Y-Grade	Semiannual	4	167.10	bbl	40,986.29	163,945.15	5.84	163,945.15	72.15	568.07	2272.28	5	2840.35	11361.41	819.73	1.64
Dehydrator After Filter	Y-Grade	Semiannual	4	5.00	bbl	1,226.40	4,905.60	5.84	4,905.60	72.15	17.00	67.99	5	84.99	339.96	24.53	0.05
Dehydrator After Filter	Y-Grade	Semiannual	4	5.00	bbl	1,226.40	4,905.60	5.84	4,905.60	72.15	17.00	67.99	5	84.99	339.96	24.53	0.05
Regenerant Filter	Y-Grade	Semiannual	4	4.80	bbl	1,177.34	4,709.38	5.84	4,709.38	72.15	16.32	65.27	5	81.59	326.36	23.55	0.05
Regenerant Coalescer	Y-Grade	Semiannual	4	22.40	bbl	5,494.27	21,977.09	5.84	21,977.09	72.15	76.15	304.60	5	380.75	1523.01	109.89	0.22
Y-Grade Prover	Y-Grade	Monthly	24	5.00	bbl	1,226.40	29,433.60	5.84	29,433.60	72.15	17.00	407.95	5	84.99	2039.75	24.53	0.29
Water Wash Coalescer	Y-Grade	Semiannual	4	160.50	bbl	39,367.44	157,469.76	5.84	157,469.76	72.15	545.63	2182.53	5	2728.17	10912.67	787.35	1.57
Lean Amine After Filters	Y-Grade	Monthly	24	342.20	gal	1,998.45	47,962.75	5.84	47,962.75	72.15	27.70	664.76	5	138.49	3323.82	39.97	0.48
Lean Amine Prefilter	Y-Grade	Monthly	24	171.10	gal	999.22	23,981.38	5.84	23,981.38	72.15	13.85	332.38	5	69.25	1661.91	19.98	0.24
Lean Amine Carbon Filter	Y-Grade	Monthly	24	4626.39	gal	27,018.12	648,434.82	5.84	648,434.82	72.15	374.47	8987.32	5	1872.36	44936.58	540.36	6.48
Rich Amine Solids Filters	Y-Grade	Monthly	24	342.20	gal	1,998.45	47,962.75	5.84	47,962.75	72.15	27.70	664.76	5	138.49	3323.82	39.97	0.48
Gasoline Treater Filter	Natural Gasoline	Monthly	24	155.88	gal	623.52	14,964.48	4.00	14,964.48	72.15	8.64	207.41	5	43.21	1037.04	12.47	0.15
Depropanizer Compressor Suction KO Drum Drain	Propane	Biannual	1	2500.00	lb	2,500.00	2,500.00	4.12	2,500.00	44.10	56.69	56.69	3	170.07	170.07	50.00	0.03
Depropanizer Compressor Suction KO Drum Drain for Maintenance	Propane	Quarterly	8	128.00	lb	128.00	1,024.00	4.12	1,024.00	44.10	2.90	23.22	3	8.71	69.66	2.56	0.01
Debutanizer Reflux Pump Drainage for Maintenance	Mixed Butanes	Quarterly	8	845.00	lb	845.00	6,760.00	4.78	6,760.00	58.12	14.54	116.31	4	58.16	465.24	16.90	0.07
Deisobutanizer Compressor KO Drum Drain	Isobutane	Biannual	1	2700.00	lb	2,700.00	2,700.00	4.78	2,700.00	58.12	46.46	46.46	4	185.82	185.82	54.00	0.03
Deisobutanizer Compressor Suction KO Drum Drain for Maintenance	Isobutane	Quarterly	8	135.00	lb	135.00	1,080.00	4.78	1,080.00	58.12	2.32	18.58	4	9.29	74.33	2.70	0.01
Deisobutanizer Reflux Pump Drain for Maintenance	Isobutane	Quarterly	8	304.00	lb	304.00	2,432.00	4.78	2,432.00	58.12	5.23	41.84	4	20.92	167.38	6.08	0.02
Refrigerant Suction KO Drum Pump Drain for Maintenance	Propylene	Quarterly	8	140.00	lb	140.00	1,120.00	-	1,120.00	58.12	2.41	19.27	4	9.64	77.08	2.80	0.01

Jefferson County NGL Fractionation Plant

Speciated MSS Waste Gas Streams Sent to Flare (EPN: FLR1)

Control Efficiency 98.0%

MSS Event Description	Compound	MSS Frequency	Frequency Counter	Amount Released				Density	Uncontrolled MSS Emissions	Molecular Weight	Moles of Hydrocarbon		Number of Carbon Moles	Moles of CO_2 from Combustion		Controlled Flare Emissions	
			(Events/yr)	per Event	Units	(lb/event)	(lb/yr)	(lb/gal)	(lb/yr)	(lb/lb-mol)	(lb-mol/hr)	(lb-mol/yr)	(mol-C/lb-mol)	(lb-mol/hr)	(lb-mol/yr)	(lb/event)	(tpy)
Propylene Loading Vent to Flare	Propylene	Semiannual	4	7.00	lb	7.00	28.00	-	28.00	58.12	0.12	0.48	4	0.48	1.93	0.14	2.8E-04
Refrigerant Compressor Case Drain Condensate	Propylene	Semiannual	4	64.00	lb	64.00	256.00	-	256.00	58.12	1.10	4.40	4	4.40	17.62	1.28	2.6E-03
Gasoline Treatment Filter	Natural Gasoline	Quarterly	8	576.00	lb	576.00	4,608.00	-	4,608.00	72.15	7.98	63.87	5	39.92	319.33	11.52	0.05
Propane Injection Pump Drain for Maintenance	Propane	Quarterly	8	294.00	lb	294.00	2,352.00	-	2,352.00	44.10	6.67	53.33	3	20.00	160.00	5.88	0.02
Isobutane Injection Pump Drain for Maintenance	Isobutane	Quarterly	8	148.00	lb	148.00	1,184.00	-	1,184.00	58.12	2.55	20.37	4	10.19	81.49	2.96	0.01
Normal Butane Injection Pump Drain for Maintenance	Butane	Quarterly	8	148.00	lb	148.00	1,184.00	-	1,184.00	58.12	2.55	20.37	4	10.19	81.49	2.96	0.01
Natural Gasoline Injection Pump Drain for Maintenance	Natural Gasoline	Quarterly	8	392.00	lb	392.00	3,136.00	-	3,136.00	72.15	5.43	43.47	5	27.17	217.33	7.84	0.03
Purge Methane from Dethanizer	Carbon Dioxide	Per hour as required	500	2.76	lb/hr	2.76	1,380.00	-	1,380.00	44.01	-	-	-	-	-	2.76	0.69
	Methane			168.35		168.35	84,175.00	-	84,175.00	16.04	10.50	5247.82	1	10.50	5247.82	3.37	0.84
	Ethane			2361.23		2,361.23	1,180,615.00	-	1,180,615.00	30.07	78.52	39262.22	2	157.05	78524.44	47.22	11.81
	Propane			7.11		7.11	3,555.00	-	3,555.00	44.10	0.16	80.61	3	0.48	241.84	0.14	0.04
TOTAL							**3,271,368.69**		**3,271,368.69**	**-**	**-**	**73,584.83**	**-**	**-**	**222,548.11**	**-**	**33.39**
MAXIMUM EVENT (lb/event)						**40,986.29**										**819.73**	
MAXIMUM EVENT (lb-mol/event)											**568.07**						
MAXIMUM HOURLY CO_2 EMISSIONS (lb-mol/hr)														**2840.35**			

Vent Gas HHV[3] (MMBtu/scf): 0.001235

Potential operation: 8760 hr/yr

Potential Emissions: Products of Combustion MSS Waste Gas Streams

Pollutant	Emission Factor		Estimated Emissions [1, 6]		Source of Emission Factor
	EF	Units	(lb/hr)[2]	(tpy)[3]	
CO_2	2840.35	lb-mol/hr	125,003.80	4,897.86	40 CFR 98 Subpart W[1]
CH_4	0.0575	lb-mol/hr	0.92	0.85	40 CFR 98 Subpart W [4]
N_2O	0.0002	lb/MMBtu	0.05	6.90	40 CFR 98 Subpart W [5]
CO_2e	-	-	125,038.62	7,054.79	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO_2. Emission factor is multiplied by molecular weight of CO_2 (44.01 lb/lb-mol) to estimate emissions.

[2] Based on maximum MSS event occurring in 1 hour.

[3] Based on annual MSS event parameters.

[4] Assumes 98% destruction of methane. Remaining 2% of methane in waste gas is emitted as methane.

[5] Uses the vent gas heating value of 1.235×10^{-3} MMBtu/scf and 1×10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

[6] Represents MSS emissions for two process trains.

Jefferson County NGL Fractionation Plant

Speciated MSS Waste Gas Stream Sent to Flare from Thermal Oxidizer KO Drum Pump Drain (EPN: FLR1)

Control Efficiency 98.0%

MSS Event Description	Compound	MSS Frequency	Frequency Counter	Amount Released				Speciated Compounds						Uncontrolled MSS Emissions	Molecular Weight	Moles of Hydrocarbon	Number of Carbon Moles	Moles of CO_2 from Combustion	Controlled Flare Emissions	
			(Events/yr)	per Event	Units	(lb/event)	(lb/yr)		(mol%)	(lb/lb-mol)	(wt%)	(lb/event)	(lb/yr)	(lb/yr)	(lb/lb-mol)	(lb-mol/yr)	(mol-C/lb-mol)	(lb-mol/yr)	(lb/event)	(tpy)
Thermal Oxidizer KO Drum Pump Drain	Sour Water	Quarterly	8	150.00	lb	150.00	1,200.00	N2	1.4E-08	3.9E-09	2.1E-08	3.2E-08	2.6E-07	2.6E-07	28.01	0	0	0	3.2E-08	1.3E-10
								Carbon Dioxide	0.06	0.03	0.14	0.22	1.73	1.73	44.01	0	-	-	0.22	8.7E-04
								Methane	2.7E-06	4.3E-07	2.4E-06	3.6E-06	2.8E-05	2.8E-05	16.04	1.8E-06	1	1.8E-06	7.1E-08	2.8E-10
								Ethane	4.5E-05	1.4E-05	7.4E-05	1.1E-04	8.9E-04	8.9E-04	30.07	3.0E-05	2	5.9E-05	2.2E-06	8.9E-09
								Propane	5.9E-06	2.6E-06	1.4E-05	2.1E-05	1.7E-04	1.7E-04	44.10	3.9E-06	3	1.2E-05	4.3E-07	1.7E-09
								Isobutane	1.5E-07	8.7E-08	4.8E-07	7.2E-07	5.7E-06	5.7E-06	58.12	9.9E-08	4	3.9E-07	1.4E-08	5.7E-11
								n-Butane	5.5E-07	3.2E-07	1.7E-06	2.6E-06	2.1E-05	2.1E-05	58.12	3.6E-07	4	1.4E-06	5.2E-08	2.1E-10
								Isopentane	1.6E-08	1.2E-08	6.3E-08	9.5E-08	7.6E-07	7.6E-07	72.15	1.1E-08	5	5.3E-08	1.9E-09	7.6E-12
								Pentane	1.9E-08	1.4E-08	7.5E-08	1.1E-07	9.0E-07	9.0E-07	72.15	1.2E-08	5	6.2E-08	2.3E-09	9.0E-12
								Cyclopentane	9.3E-08	6.5E-08	3.6E-07	5.4E-07	4.3E-06	4.3E-06	70.10	6.1E-08	5	3.1E-07	1.1E-08	4.3E-11
								Hexane	1.2E-09	1.0E-09	5.7E-09	8.5E-09	6.8E-08	6.8E-08	86.10	7.9E-10	6	4.7E-09	1.7E-10	6.8E-13
								Methylcyclopentane	2.3E-08	1.9E-08	1.1E-07	1.6E-07	1.3E-06	1.3E-06	84.16	1.5E-08	6	9.1E-08	3.2E-09	1.3E-11
								Cyclohexane	4.0E-08	3.4E-08	1.8E-07	2.8E-07	2.2E-06	2.2E-06	84.16	2.6E-08	6	1.6E-07	5.5E-09	2.2E-11
								Methylcyclohexane	4.7E-09	4.6E-09	2.5E-08	3.8E-08	3.0E-07	3.0E-07	98.19	3.1E-09	7	2.2E-08	7.6E-10	3.0E-12
								Benzene	8.2E-05	6.4E-05	3.5E-04	5.3E-04	4.2E-03	4.2E-03	78.11	5.4E-05	6	3.2E-04	1.1E-05	4.2E-08
								Toluene	1.9E-05	1.8E-05	9.6E-05	1.4E-04	1.2E-03	1.2E-03	92.14	1.2E-05	7	8.7E-05	2.9E-06	1.2E-08
								Ethylbenzene	0	0	0	0	0	0	106.17	0	8	0	0	0
								o-Xylene	1.5E-06	1.6E-06	8.7E-06	1.3E-05	1.0E-04	1.0E-04	106.16	9.9E-07	8	7.9E-06	2.6E-07	1.0E-09
								p-Xylene	1.6E-06	1.7E-06	9.3E-06	1.4E-05	1.1E-04	1.1E-04	106.16	1.1E-06	8	8.4E-06	2.8E-07	1.1E-09
								m-Xylene	1.2E-06	1.3E-06	7.0E-06	1.0E-05	8.4E-05	8.4E-05	106.16	7.9E-07	8	6.3E-06	2.1E-07	8.4E-10
								Hydrogen Sulfide	0	0	0	0	0	0	34.08	0	0	0	0	0
								Methyl Mercaptan	1.8E-05	8.7E-06	4.7E-05	7.1E-05	5.7E-04	5.7E-04	48.11	1.2E-05	2	2.4E-05	1.4E-06	5.7E-09
								Ethyl Mercaptan	4.4E-06	2.7E-06	1.5E-05	2.2E-05	1.8E-04	1.8E-04	62.13	2.9E-06	1	2.9E-06	4.5E-07	1.8E-09
								n-Propyl Mercaptan	6.8E-07	5.2E-07	2.8E-06	4.3E-06	3.4E-05	3.4E-05	76.16	4.5E-07	3	1.3E-06	8.5E-08	3.4E-10
								n-Butyl Mercaptan	2.7E-08	2.4E-08	1.3E-07	2.0E-07	1.6E-06	1.6E-06	90.20	1.8E-08	4	7.1E-08	4.0E-09	1.6E-11
								Carbon Disulfide	7.3E-08	5.6E-08	3.0E-07	4.6E-07	3.7E-06	3.7E-06	76.14	4.8E-08	1	4.8E-08	9.1E-09	3.7E-11
								DMS	2.6E-06	1.6E-06	8.8E-06	1.3E-05	1.1E-04	1.1E-04	62.13	1.7E-06	2	3.4E-06	2.7E-07	1.1E-09
								DMDS	1.4E-07	1.3E-07	7.2E-07	1.1E-06	8.7E-06	8.7E-06	94.19	9.2E-08	2	1.8E-07	2.2E-08	8.7E-11
								Carbonyl Sulfide	1.6E-08	9.6E-09	5.3E-08	7.9E-08	6.3E-07	6.3E-07	60.07	1.1E-08	1	1.1E-08	1.6E-09	6.3E-12
								Methanol	1.65	0.53	2.89	4.34	34.73	34.73	32.04	1.08	1	1.08	0.09	3.5E-04
								2-Propanol	2.5E-08	1.5E-08	8.2E-08	1.2E-07	9.9E-07	9.9E-07	60.11	1.6E-08	3	4.9E-08	2.5E-09	9.9E-12
								Water	98.29	17.71	96.96	145.44	1163.53	1,163.53	18.02	0	0	0	145.44	0.58
TOTAL							**1,200.00**							**1,200.00**		**2.16**	**-**	**2.16**	**-**	**1.16**

Vent Gas HHV[3] (MMBtu/scf): 0.00124

Potential operation: 8760 hr/yr

Potential Emissions: Products of Combustion MSS Waste Gas Streams

Pollutant	Emission Factor		Estimated Emissions [1, 4]	Source of Emission Factor
	EF	Units	(tpy)	
CO_2	2.20	lb-mol/yr	0.05	40 CFR 98 Subpart W [1]
CH_4	3.5E-08	lb-mol/yr	2.8E-10	40 CFR 98 Subpart W [2]
N_2O	0.0002	lb/MMBtu	2.0E-04	40 CFR 98 Subpart W [3]
CO_2e	-	-	0.11	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO_2. Emission factor is multiplied by molecular weight of CO_2 (44.01 lb/lb-mol) to estimate emissions.

[2] Assumes 99.5% destruction of methane. Remaining 0.5% of methane in waste gas is emitted as methane.

[3] Uses the vent gas heating value of 1.235 x 10^{-3} MMBtu/scf and 1 x 10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

[4] Represents MSS emissions for two process trains.

Jefferson County NGL Fractionation Plant

Speciated MSS Waste Gas Stream Sent to Flare when Thermal Oxidizer Down for Maintenance (EPN: FLR1)

Control Efficiency 98.0%

MSS Event Description	Frequency Counter	Compound	Seal Gas Leaks	Natural Gasoline Treater Flash Pot Vent	Amine Unit Vents	Total Vent Stream		Uncontrolled MSS Emissions	Molecular Weight	Moles of Hydrocarbon	Number of Carbon Moles	Moles of CO_2 from Combustion	Controlled Flare Emissions	
	(Hours/yr)		(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb-mol/hr)	(lb/yr)	(lb/lb-mol)	(lb-mol/yr)	(mol-C/lb-mol)	(lb-mol/yr)	(lb/hr)	(tpy)
Thermal Oxidizer (TO1 or TO2) Streams to Flare During Thermal Oxidizer Maintenance	500	Nitrogen	-	-	-	0	0	0	28.01	0	0	0	-	-
		Carbon Dioxide	-	-	935.3573	935.36	21.25	467678.65	44.01	0	-	-	935.36	233.84
		Methane	-	-	4.6267	4.63	0.29	2313.37	16.04	144.23	1	144.23	0.09	2.3E-02
		Ethane	-	-	95.4822	95.48	3.18	47741.09	30.07	1587.67	2	3175.33	1.9E+00	4.8E-01
		Propane	7.50	-	28.1380	35.64	0.81	17819.00	44.10	404.06	3	1212.18	7.1E-01	1.8E-01
		Isobutane	3.49	2.1E-01	-	3.70	0.06	1848.50	58.12	31.80	4	127.22	7.4E-02	1.8E-02
		n-Butane	-	0.0029	3.8098	3.81	0.07	1906.33	58.12	32.80	4	131.20	7.6E-02	1.9E-02
		Isopentane	-	-	-	0	0	0	72.15	0	5	0	0	0
		Pentane	-	0.17	-	0.17	2.4E-03	85.90	72.15	1.2E+00	5	5.95	3.4E-03	8.6E-04
		Cyclopentane	-	0.0095	0.1030	0.11	1.6E-03	56.27	70.10	8.0E-01	5	4.0E+00	2.3E-03	5.6E-04
		Hexane*	-	0.0389	-	0.04	4.5E-04	19.45	86.10	2.3E-01	6	1.4E+00	7.8E-04	1.9E-04
		Methyl Cyclopentane	-	0.0109	-	0.01	1.3E-04	5.45	84.16	6.5E-02	6	3.9E-01	2.2E-04	5.5E-05
		Cyclohexane	-	0.0534	0.0640	0.12	1.4E-03	58.68	84.16	7.0E-01	6	4.2E+00	2.3E-03	5.9E-04
		Methyl Cyclohexane	-	0.0037	-	3.7E-03	3.8E-05	1.9E+00	98.19	1.9E-02	7	1.3E-01	7.4E-05	1.9E-05
		Benzene*	-	0.0056	2.1246	2.13	0.03	1065.10	78.11	13.64	6	81.82	4.3E-02	1.1E-02
		Toluene*	-	0.0013	0.7445	0.75	0.01	372.90	92.14	4.0E+00	7	28.33	1.5E-02	3.7E-03
		Ethylbenzene*	-	-	0	0	0	0	106.17	0	8	0	0	0
		o-Xylene*	-	-	0.0556	0.06	5.2E-04	27.81	106.16	2.6E-01	8	2.1E+00	1.1E-03	2.8E-04
		p-Xylene*	-	-	0.0599	0.06	5.6E-04	29.94	106.16	2.8E-01	8	2.3E+00	1.2E-03	3.0E-04
		m-Xylene*	-	-	0.0449	0.04	4.2E-04	22.45	106.16	2.1E-01	8	1.7E+00	9.0E-04	2.2E-04
		Hydrogen Sulfide	-	-	0	0	0	0	34.08	0	0	0	0	0
		Methyl Mercaptan	-	0.0001	0.2478	0.25	5.2E-03	123.93	48.11	2.6E+00	2	5.15	5.0E-03	1.2E-03
		Ethyl Mercaptan	-	0.0002	0.0783	0.08	1.3E-03	39.24	62.13	6.3E-01	1	6.3E-01	1.6E-03	3.9E-04
		n-Propyl Mercaptan	-	-	0.0156	0.02	2.1E-04	7.81	76.16	1.0E-01	3	3.1E-01	3.1E-04	7.8E-05
		n-Butyl Mercaptan	-	-	0.0019	1.9E-03	2.1E-05	9.5E-01	90.20	1.1E-02	4	4.2E-02	3.8E-05	9.5E-06
		Carbon Disulfide*	-	1.0507	0.0059	1.06	0.01	528.28	76.14	6.94	1	6.94	2.1E-02	5.3E-03
		DMS	-	-	0.0170	0.02	2.7E-04	8.48	62.13	1.4E-01	2	2.7E-01	3.4E-04	8.5E-05
		DMDS	-	-	0.0010	9.5E-04	1.0E-05	4.8E-01	94.19	5.1E-03	2	1.0E-02	1.9E-05	4.8E-06
		Carbonyl Sulfide*	-	-	0.0023	2.3E-03	3.8E-05	1.1E+00	60.07	1.9E-02	1	1.9E-02	4.6E-05	1.1E-05
		Methanol*	-	-	11.4895	11.49	0.36	5744.77	32.04	179.30	1	179.30	0.23	5.7E-02
		2-Propanol	-	-	0.0013	1.3E-03	2.2E-05	6.6E-01	60.11	1.1E-02	3	3.3E-02	2.6E-05	6.6E-06
		Propylene	7.15	-	-	7.15	0.17	3575.00	42.08	84.96	3	254.87	0.14	3.6E-02
TOTAL								**551,083.48**		**2,496.68**	**-**	**5,369.94**	**-**	**234.67**

Vent Gas HHV[3] (MMBtu/scf): 0.001235

Potential operation: 8760 hr/yr

Potential Emissions: Products of Combustion MSS Waste Gas Streams

Pollutant	Emission Factor		Estimated Emissions [1, 4]	Source of Emission Factor
	EF	Units	(tpy)	
CO_2	15996.59	lb-mol/yr	352.00	40 CFR 98 Subpart W [1]
CH_4	2.88	lb-mol/yr	2.3E-02	40 CFR 98 Subpart W [2]
N_2O	0.0002	lb/MMBtu	2.3E-01	40 CFR 98 Subpart W [3]
CO_2e	-	-	425.04	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO_2. Emission factor is multiplied by molecular weight of CO_2 (44.01 lb/lb-mol) to estimate emissions.

[2] Assumes 99.5% destruction of methane. Remaining 0.5% of methane in waste gas is emitted as methane.

[3] Uses the vent gas heating value of 1.235 x 10^{-3} MMBtu/scf and 1 x 10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

[4] Represents MSS emissions for two process trains.

Jefferson County NGL Fractionation Plant

Thermal Oxidizer Emission Summary Sheet

Source ID Number	TO1		
Equipment ID	TO1		
Source Description	Thermal Oxidizer 1		
Equipment Usage			
Equipment Make		Proposed Operation	8760 hr/yr
Equipment Model			
Serial Number			
Date in Service			

Potential Emissions Summary (fuel combustion + waste gas combustion)

Pollutant	**Fuel Gas Emissions**		**Waste Gas Emissions** [1]		**Total Estimated Emissions**	
	(lb/hr)	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**
CO_2	596.82	2,614.06	1,417.28	6,205.93	2,014.10	8,819.99
CH_4	0.01	0.05	5.0E-03	0.02	0.02	0.07
N_2O	1.0E-03	5.0E-03	4.7E-04	2.1E-03	1.5E-03	0.01
CO_2e	597.34	2,616.65	1,417.53	6,207.02	2,014.87	8,823.67

[1] Waste gas emissions include destruction of vents from amine system, gasoline treater flash pot, and seal gas leaks.

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: THERMAL OXIDIZER

Facility ID:	TBD	**Facility:**	Jefferson County NGL Fractionation Plant

Equipment Information

Source ID Number:	TO1	Model:	
Name 2:	TO1	Serial Number:	TBD
Name 3:	Thermal Oxidizer 1	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3318349	Permit Status:	TBD
Easting:	392641	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (mmbtu/hr):	5
Status:	Not Yet Built	Fuel Heat Value (btu/scf):	1006.68
Ext. Comb.Type:	Thermal Oxidizer		
Fuel Type:	Natural Gas		
Equipment Usage:			
Configuration:			
		Potential fuel usage (MMscf/yr):	43.51

Stack Parameters

Stack Name:	TO1	Height (ft):	55
Stack Number:		Diameter (ft):	5
Emission Percent:		Temperature (oF):	750
Stack Angle (o):		Flow (ACFM):	10,481
Raincap:		Velocity (ft/s):	8.9

Control Model

Emission Controls:

0.004966836

Potential operation: 8760 hr/yr

Potential Emissions: Products of Combustion: fuel

Pollutant	Emission Factor		Nominal Rating	Hrs of Operation	Estimated Emissions [1, 2]		Source of Emission Factor
	EF	Units	(MMBtu/hr)	(hrs/yr)	(lb/hr)	(tpy)	
CO_2	120161	lb/MMscf	5	8760	596.82	2,614.06	40 CFR 98 Subpart C, Table C-1
CH_4	2.27	lb/MMscf	5	8760	0.01	0.05	40 CFR 98 Subpart C, Table C-2
N_2O	0.23	lb/MMscf	5	8760	0.001	0.005	40 CFR 98 Subpart C, Table C-2
CO_2e					597.34	2,616.65	

[1] Hourly emissions estimated as follows: EF lb/MMscf x 5 MMBtu/hr / 1006.68 Btu/scf.

[2] Annual emissions estimated as follows: EF lb/MMscf x 5 MMBtu/hr / 1006.68 Btu/scf x 8,760 hr/yr / 2,000 lb/ton.

Notes **Notes Date:**

Jefferson County NGL Fractionation Plant

EPN TO1 Emissions from Compressor Seal Gas Vents

Compound Name	Compound Molecular Weight	Total Vent Discharge to TO1			Moles of Hydrocarbon	Number of Carbon Atoms per Molecule	Moles of CO_2 from Combustion
	(lb/lb-mol)	(scfh)[1]	(lb-mol/hr)[2]	(lb/hr)	(lb-mol/hr)		(lb-mol/hr)
Propylene	42.08	64.8	0.17	7.15	0.17	3	0.51
Propane	44.10	64.8	0.17	7.5	0.17	3	0.51
Isobutane	58.12	21.6	0.06	3.49	0.06	4	0.240000
Total				**18.14**	**0.40**		**1.26**

[1] At standard conditions of 60 °F and 14.7 psia.

[2] Based on Ideal Gas Law using scfh provided.

Vent Gas HHV[2] (MMBtu/scf): 0.001235

Potential operation: 8760 **hrs/yr**

Potential Emissions: Products of Combustion Compressor Seal Gas Vents

Pollutant	Emission Factor	Units	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
CO_2	1.26	lb-mol/hr	8760	55.45	242.88	40 CFR 98 Subpart W [1]
N_2O	0.0002	lb/MMBtu	8760	3.7E-05	1.6E-04	40 CFR 98 Subpart W [2]
CO_2e				55.46	242.93	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO_2. Emission factor is multiplied by molecular weight of CO_2 (44.01 lb/lb-mol) to estimate emissions.

[2] Uses the vent gas heating value of 1.235×10^{-3} MMBtu/scf and 1×10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

Jefferson County NGL Fractionation Plant

EPN TO1 Emissions from Gasoline Treater Flash Pot Vent

Compound Name	Compound Molecular Weight	Compound Percentage	Total Vent Discharge to TO1		Speciated Vent Discharge to TO1		Moles of Hydrocarbon	Number of Carbon Atoms per Molecule	Moles of CO_2 from Combustion
	(lb/lb-mol)	(mol%)	(scfh)[2]	(lb-mol/hr)[3]	(lb-mol/hr)	(lb/hr)	(lb-mol/hr)		(lb-mol/hr)
Ethyl mercaptan	62.13	0.00025	523.5	1.38	0.000003	0.0002	3.0E-06	2	6.0E-06
Methyl mercaptan	48.11	0.00025			0.000003	0.0001	3.0E-06	1	3.0E-06
Carbon disulfide*	76.14	1.0			0.0138	1.0507	1.4E-02	1	1.4E-02
n-Butane	58.12	0.00365			0.00005	0.0029	5.0E-05	4	2.0E-04
Isobutane	58.12	0.25805			0.003561	0.207	3.6E-03	4	1.4E-02
Pentane	72.15	0.1725			0.002381	0.1718	2.4E-03	5	1.2E-02
Cyclopentane	70.1	0.00975			0.000135	0.0095	1.4E-04	5	6.8E-04
Hexane*	86.1	0.03275			0.000452	0.0389	4.5E-04	6	2.7E-03
Methyl Cyclopentane	84.16	0.00935			0.000129	0.0109	1.3E-04	6	7.7E-04
Cyclohexane	84.16	0.046			0.000635	0.0534	6.4E-04	6	3.8E-03
Methyl Cyclohexane	98.19	0.00275			0.000038	0.0037	3.8E-05	7	2.7E-04
Benzene*	78.11	0.0052			0.000072	0.0056	7.2E-05	6	4.3E-04
Toluene*	92.14	0.00105			0.000014	0.0013	1.4E-05	7	9.8E-05
Inert Compounds [1]		98.45845			1.358727	-	-	-	-
Total		**100.00**			**1.38**	**1.56**	**0.02**		**0.05**

[1] Consists of oxygen, nitrogen, and water.

[2] At standard conditions of 60 °F and 14.7 psia.

[3] Based on Ideal Gas Law using scfh provided.

Vent Gas HHV[2] (MMBtu/scf): 0.001235

Potential operation: 8760 **hrs/yr**

Potential Emissions: Products of Combustion Gasoline Treater Flash Pot Vent

Pollutant	Emission Factor	Units	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
CO_2	0.05	lb-mol/hr	8760	2.20	9.64	40 CFR 98 Subpart W [1]
N_2O	0.0002	lb/MMBtu	8760	2.0E-06	8.7E-06	40 CFR 98 Subpart W [2]
CO_2e				2.20	9.64	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO_2. Emission factor is multiplied by molecular weight of CO_2 (44.01 lb/lb-mol) to estimate emissions.

[2] Uses the vent gas heating value of 1.235 x 10^{-3} MMBtu/scf and 1 x 10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

Jefferson County NGL Fractionation Plant

EPN TO1 Emissions from Gasoline Treater Flash Pot Daily Purge

Compound Name	Compound Molecular Weight	Speciated Vent Discharge to TO1 [1]	Moles of Hydrocarbon	Number of Carbon Atoms per Molecule	Vent Frequency	Moles of CO_2 from Combustion	
	(lb/lb-mol)	(lb/hr)	(lb-mol/hr)		(hrs/yr)	(lb-mol/hr)	(lb-mol/yr)
n-Butane	58.12	0.000839	1.44E-05	4	730	6.00E-05	0.04
Isopentane	72.15	0.06530	9.05E-04	5		4.53E-03	3.31
Pentane	72.15	0.04620	6.40E-04	5		3.20E-03	2.34
Cyclopentane	70.1	0.00514	7.33E-05	5		3.70E-04	0.27
Hexane*	86.1	0.00925	1.07E-04	6		6.40E-04	0.47
Methyl Cyclopentane	84.16	0.00537	6.38E-05	6		3.80E-04	0.28
Cyclohexane	84.16	0.00267	3.17E-05	6		1.90E-04	0.14
Methyl Cyclohexane	98.19	0.00150	1.53E-05	7		1.10E-04	0.08
Benzene*	78.11	0.00389	4.98E-05	6		3.00E-04	0.22
Toluene*	92.14	0.00110	1.19E-05	7		8.00E-05	0.06
Mixed Xylenes*	106.16	0.000185	1.74E-06	8		1.00E-05	7.0E-03
Total		**0.14**	**1.91E-03**			**0.01**	**7.22**

[1] Provided by engineering company; generated by process modeling software.

Vent Gas HHV[2] (MMBtu/scf): 0.001235

Potential operation: 730 **hrs/yr**

Potential Emissions: Products of Combustion Gasoline Treater Flash Pot Vent

Pollutant	Emission Factor	Units	Hrs of Operation (hrs/yr)	Estimated (lb/hr)	(tpy)	Source of Emission Factor
CO_2	0.01	lb-mol/hr	730	0.44	0.16	40 CFR 98 Subpart W [1]
N_2O	0.0002	lb/MMBtu	730	1.8E-07	7.0E-08	40 CFR 98 Subpart W [2]
CO_2e				0.44	0.16	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO2. Emission factor is multiplied by molecular weight of CO2 (44.01 lb/lb-mol) to estimate emissions.

[2] Uses the vent gas heating value of 1.235×10^{-3} MMBtu/scf and 1×10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

Jefferson County NGL Fractionation Plant

EPN TO1 Emissions from Amine Unit Vent Gas

Control Efficiency 99.90%

Compound	Rich Amine Flash Drum Emissions		Acid Gas Emissions		Total Uncontrolled Waste Gas Emissions	Molecular Weight	Total Moles of Hydrocarbon	Number of Carbon Atoms per Molecule	Moles of CO_2 from Combustion	Controlled Emissions	
	(lb-mol/hr)	(lb/hr)	(lb-mol/hr)	(lb/hr)	(lb/hr)	(lb/lb-mol)	(lb-mol/hr)		(lb-mol/hr)	(lb/hr)	(tpy)
carbon dioxide	5.0E-05	0.0022	21.2532	935.3551	935.36	44.01	-	-	-	935.36	4,096.86
Sulfur dioxide	-	-	-	-	-	64.06	-	-	-	0.46	2.01
hydrogen sulfide	0	0	0	0	0	34.08	0	-	-	0	0
Methyl mercaptan	7.0E-05	0.0034	0.0051	0.2444	0.25	48.11	0.0052	2	0.01	2.5E-04	1.1E-03
Ethyl mercaptan	2.0E-05	0.0012	0.0012	0.0770	0.08	62.13	0.0013	1	1.3E-03	7.8E-05	3.4E-04
n-Propyl mercaptan	5.0E-06	0.0004	0.0002	0.0152	0.02	76.16	0.0002	3	6.2E-04	1.6E-05	6.8E-05
n-Butyl mercaptan	1.0E-06	0.0001	2.0E-05	0.0018	1.9E-03	90.20	0.0000	4	8.4E-05	1.9E-06	8.3E-06
Carbon disulfide*	7.0E-06	0.0005	0.0001	0.0053	0.01	76.14	0.0001	1	7.7E-05	5.9E-06	2.6E-05
DMS	3.0E-06	0.0002	0.0003	0.0168	0.02	62.13	0.0003	2	5.5E-04	1.7E-05	7.4E-05
DMDS	1.0E-07	9.4E-06	1.0E-05	0.0009	9.5E-04	94.19	1.0E-05	2	2.0E-05	9.5E-07	4.2E-06
Carbonyl sulfide*	8.0E-06	0.0005	3.0E-05	0.0018	2.3E-03	60.07	3.8E-05	1	3.8E-05	2.3E-06	1.0E-05
Water	0.0200	0.3609	2.2044	39.7226	40.08	18.02	-	-	-	40.08	175.57
methane	0.2161	3.4661	0.0724	1.1607	4.63	16.04	0.2885	1	0.29	4.6E-03	0.02
ethane	2.1086	63.4059	1.0667	32.0763	95.48	30.07	3.1753	2	6.35	0.10	0.42
propane	0.4558	20.1021	0.1822	8.0359	28.14	44.10	0.6381	3	1.91	0.03	0.12
i-butane	0.0275	1.5977	0.0074	0.4289	2.03	58.12	0.0349	4	0.14	2.0E-03	8.9E-03
n-butane	0.0475	2.7578	0.0181	1.0520	3.81	58.12	0.0656	4	0.26	3.8E-03	0.02
i-pentane	0.0043	0.3117	0.0011	0.0772	0.39	72.15	0.0054	5	0.03	3.9E-04	1.7E-03
n-pentane	0.0035	0.2504	0.0010	0.0736	0.32	72.15	0.0045	5	0.02	3.2E-04	1.4E-03
Cyclopentane	0.0006	0.0393	0.0009	0.0638	0.10	70.10	0.0015	5	0.01	1.0E-04	4.5E-04
n-hexane*	0.0005	0.0431	0.0001	0.0103	0.05	86.10	0.0006	6	3.7E-03	5.3E-05	2.3E-04
Methylcyclopentane	0.0004	0.0362	0.0004	0.0362	0.07	84.16	0.0009	6	5.2E-03	7.2E-05	3.2E-04
Cyclohexane	0.0003	0.0261	0.0005	0.0379	0.06	84.16	0.0008	6	4.6E-03	6.4E-05	2.8E-04
Methylcyclohexane	0.0001	0.0137	0.0001	0.0108	0.02	98.19	0.0003	7	1.8E-03	2.5E-05	1.1E-04
Benzene*	0.0005	0.0422	0.0267	2.0824	2.12	78.11	0.0272	6	0.16	2.1E-03	9.3E-03
Toluene*	0.0001	0.0074	0.0080	0.7371	0.74	92.14	0.0081	7	0.06	7.4E-04	3.3E-03
Ethylbenzene*	0	0	0	0	0	106.17	0	8	0	0	0
o-xylene*	4.0E-06	0.0004	0.0005	0.0552	0.06	106.16	0.0005	8	4.2E-03	5.6E-05	2.4E-04
p-xylene*	4.0E-06	0.0004	0.0006	0.0594	0.06	106.16	0.0006	8	4.5E-03	6.0E-05	2.6E-04
m-xylene*	3.0E-06	0.0003	0.0004	0.0446	0.04	106.16	0.0004	8	3.4E-03	4.5E-05	2.0E-04
Methanol*	6.0E-05	0.0019	0.3585	11.4876	11.49	32.04	0.3586	1	0.36	0.01	0.05
2-Propanol	2.0E-06	0.0001	2.0E-05	0.0012	1.3E-03	60.11	2.2E-05	3	6.6E-05	1.3E-06	5.8E-06

Jefferson County NGL Fractionation Plant

EPN TO1 Emissions from Amine Unit Vent Gas

Control Efficiency 99.90%

Compound	Rich Amine Flash Drum Emissions		Acid Gas Emissions		Total Uncontrolled Waste Gas Emissions	Molecular Weight	Total Moles of Hydrocarbon	Number of Carbon Atoms per Molecule	Moles of CO_2 from Combustion	Controlled Emissions	
	(lb-mol/hr)	(lb/hr)	(lb-mol/hr)	(lb/hr)	(lb/hr)	(lb/lb-mol)	(lb-mol/hr)		(lb-mol/hr)	(lb/hr)	(tpy)
DEAmine*	3.0E-08	3.6E-06	1.0E-17	1.2E-15	3.6E-06	119.16	3.0E-08	4	1.2E-07	3.6E-09	1.6E-08
Piperazine	0	0	0	0	0	86.14	0	4	0	0	0
Total	**2.89**	**92.47**	**25.21**	**1032.97**	**1125.44**		**4.62**		**9.63**	**976.05**	**4,275.09**
Total Hydrocarbons	**2.87**	**92.11**	**1.75**	**57.89**	**150.00**		**4.62**		**-**	**0.15**	**0.66**
Total HAPs	**1.2E-03**	**0.10**	**0.39**	**14.48**	**14.58**		**0.40**		**-**	**0.01**	**0.06**
Total VOC	**0.54**	**25.24**	**0.61**	**24.66**	**49.89**		**1.15**		**-**	**0.05**	**0.22**

*HAP

Vent Gas HHV[3] (MMBtu/scf): 0.001235

Potential operation: 8760 **hrs/yr**

Potential Emissions: Products of Combustion Amine Unit Vent Gas

Pollutant	Emission Factor	Units	Nominal Rating (MMBtu/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
CO_2	30.88	lb-mol/hr	-	8760	1359.19	5953.24	40 CFR 98 Subpart W [1]
CH_4	0.0046	lb/hr	-	8760	5.0E-03	0.02	40 CFR 98 Subpart W [2]
N_2O	0.0002	lb/MMBtu	-	8760	4.3E-04	1.9E-03	40 CFR 98 Subpart W [3]
CO_2e					1359.43	5954.29	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO_2. Emission factor is multiplied by molecular weight of CO_2 (44.01 lb/lb-mol) to estimate

[2] Assumes 98% destruction of methane. Remaining 2% of methane in waste gas is emitted as methane.

[3] Uses the vent gas heating value of 1.235 x 10^{-3} MMBtu/scf and 1 x 10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

Jefferson County NGL Fractionation Plant

Thermal Oxidizer Emission Summary Sheet

Source ID Number	TO2		
Equipment ID	TO2		
Source Description	Thermal Oxidizer 2		
Equipment Usage			
Equipment Make		Proposed Operation	8760 hr/yr
Equipment Model			
Serial Number			
Date in Service			

Potential Emissions Summary (fuel combustion + waste gas combustion)

Pollutant	**Fuel Gas Emissions**		**Waste Gas Emissions**		**Total Estimated Emissions**	
	(lb/hr)	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**
CO_2	596.82	2,614.06	1,417.28	6,205.93	2,014.10	8,819.99
CH_4	0.01	0.05	5.0E-03	0.02	0.02	0.07
N_2O	1.0E-03	5.0E-03	4.7E-04	2.1E-03	1.5E-03	0.01
CO_2e	597.34	2,616.65	1,417.53	6,207.02	2,014.87	8,823.67

[1] Waste gas emissions include destruction of vents from amine system, gasoline treater flash pot, and seal gas leaks.

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: THERMAL OXIDIZER

Facility ID: TBD **Facility:** Jefferson County NGL Fractionation Plant

Equipment Information

Source ID Number:	TO2	Model:	
Name 2:	TO2	Serial Number:	TBD
Name 3:	Thermal Oxidizer 2	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3318118	Permit Status:	TBD
Easting:	392644	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (mmbtu/hr):	5
Status:	Not Yet Built	Fuel Heat Value (btu/scf):	1006.68
Ext. Comb.Type:	Thermal Oxidizer		
Fuel Type:	Natural Gas		
Equipment Usage:			
Configuration:			
		Potential fuel usage (MMscf/yr):	43.51

Stack Parameters

Stack Name:	TO2	Height (ft):	55
Stack Number:		Diameter (ft):	5
Emission Percent:		Temperature (oF):	750
Stack Angle (o):		Flow (ACFM):	10,481
Raincap:		Velocity (ft/s):	8.9

Control Model

Emission Controls:

Potential operation: 8760 hr/yr

Potential Emissions: Products of Combustion: fuel

Pollutant	Emission Factor		Nominal Rating	Hrs of Operation	Estimated Emissions		Source of Emission Factor
	EF	Units	(MMBtu/hr)	(hrs/yr)	(lb/hr)	(tpy)	
CO_2	120161	lb/MMscf	5	8760	596.82	2,614.06	40 CFR 98 Subpart C, Table C-1
CH_4	2.27	lb/MMscf	5	8760	0.01	0.05	40 CFR 98 Subpart C, Table C-2
N_2O	0.23	lb/MMscf	5	8760	0.001	0.005	40 CFR 98 Subpart C, Table C-2
CO_2e					597.34	2,616.65	

[1] Hourly emissions estimated as follows: EF lb/MMscf x 5 MMBtu/hr / 1006.68 Btu/scf.

[2] Annual emissions estimated as follows: EF lb/MMscf x 5 MMBtu/hr / 1006.68 Btu/scf x 8,760 hr/yr / 2,000 lb/ton.

Notes **Notes Date:**

Jefferson County NGL Fractionation Plant

EPN TO2 Emissions from Compressor Seal Gas Vents

Compound Name	Compound Molecular Weight	Total Vent Discharge to TO2			Moles of Hydrocarbon	Number of Carbon Atoms per Molecule	Moles of CO_2 from Combustion
	(lb/lb-mol)	(scfh)[1]	(lb-mol/hr)[2]	(lb/hr)	(lb-mol/hr)		(lb-mol/hr)
Propylene	42.08	64.8	0.17	7.15	0.17	3	0.51
Propane	44.10	64.8	0.17	7.5	0.17	3	0.51
Isobutane	58.12	21.6	0.06	3.49	0.06	4	0.240000
Total				**18.14**	**0.40**		**1.26**

[1] At standard conditions of 60 °F and 14.7 psia.

[2] Based on Ideal Gas Law using scfh provided.

Vent Gas HHV[2] (MMBtu/scf): 0.001235

Potential operation: 8760 **hrs/yr**

Potential Emissions: Products of Combustion Compressor Seal Gas Vents

Pollutant	Emission Factor	Units	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
CO_2	1.26	lb-mol/hr	8760	55.45	242.88	40 CFR 98 Subpart W [1]
N_2O	0.0002	lb/MMBtu	8760	3.7E-05	1.6E-04	40 CFR 98 Subpart W [2]
CO_2e				55.46	242.93	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO_2. Emission factor is multiplied by molecular weight of CO_2 (44.01 lb/lb-mol) to estimate emissions.

[2] Uses the vent gas heating value of 1.235 x 10^{-3} MMBtu/scf and 1 x 10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

Jefferson County NGL Fractionation Plant

EPN TO2 Emissions from Gasoline Treater Flash Pot Vent

Compound Name	Compound Molecular Weight	Compound Percentage	Total Vent Discharge to TO2		Speciated Vent Discharge to TO2		Moles of Hydrocarbon	Number of Carbon Atoms per Molecule	Moles of CO_2 from Combustion
	(lb/lb-mol)	(mol%)	(scfh)[2]	(lb-mol/hr)[3]	(lb-mol/hr)	(lb/hr)	(lb-mol/hr)		(lb-mol/hr)
Ethyl mercaptan	62.13	0.00025	523.5	1.38	0.000003	0.0002	3.0E-06	2	6.0E-06
Methyl mercaptan	48.11	0.00025			0.000003	0.0001	3.0E-06	1	3.0E-06
Carbon disulfide*	76.14	1.0			0.0138	1.0507	1.4E-02	1	1.4E-02
n-Butane	58.12	0.00365			0.00005	0.0029	5.0E-05	4	2.0E-04
Isobutane	58.12	0.25805			0.003561	0.207	3.6E-03	4	1.4E-02
Pentane	72.15	0.1725			0.002381	0.1718	2.4E-03	5	1.2E-02
Cyclopentane	70.1	0.00975			0.000135	0.0095	1.4E-04	5	6.8E-04
Hexane*	86.1	0.03275			0.000452	0.0389	4.5E-04	6	2.7E-03
Methyl Cyclopentane	84.16	0.00935			0.000129	0.0109	1.3E-04	6	7.7E-04
Cyclohexane	84.16	0.046			0.000635	0.0534	6.4E-04	6	3.8E-03
Methyl Cyclohexane	98.19	0.00275			0.000038	0.0037	3.8E-05	7	2.7E-04
Benzene*	78.11	0.0052			0.000072	0.0056	7.2E-05	6	4.3E-04
Toluene*	92.14	0.00105			0.000014	0.0013	1.4E-05	7	9.8E-05
Inert Compounds [1]		98.45845			1.358727	-	-	-	-
Total		**100.00**			**1.38**	**1.56**	**0.02**		**0.05**

[1] Consists of oxygen, nitrogen, and water.

[2] At standard conditions of 60 °F and 14.7 psia.

[3] Based on Ideal Gas Law using scfh provided.

Vent Gas HHV[2] (MMBtu/scf): 0.001235

Potential operation: 8760 **hrs/yr**

Potential Emissions: Products of Combustion Gasoline Treater Flash Pot Vent

Pollutant	Emission Factor	Units	Hrs of Operation (hrs/yr)	Estimated (lb/hr)	Estimated (tpy)	Source of Emission Factor
CO_2	0.05	lb-mol/hr	8760	2.20	9.64	40 CFR 98 Subpart W [1]
N_2O	0.0002	lb/MMBtu	8760	2.0E-06	8.7E-06	40 CFR 98 Subpart W [2]
CO_2e				2.20	9.64	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO_2. Emission factor is multiplied by molecular weight of CO_2 (44.01 lb/lb-mol) to estimate emissions.

[2] Uses the vent gas heating value of 1.235 x 10^{-3} MMBtu/scf and 1 x 10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

Jefferson County NGL Fractionation Plant

EPN TO2 Emissions from Gasoline Treater Flash Pot Daily Purge

Compound Name	Compound Molecular Weight	Speciated Vent Discharge to TO2 [1]	Moles of Hydrocarbon	Number of Carbon Atoms per Molecule	Vent Frequency	Moles of CO_2 from Combustion	
	(lb/lb-mol)	(lb/hr)	(lb-mol/hr)		(hrs/yr)	(lb-mol/hr)	(lb-mol/yr)
n-Butane	58.12	0.000839	1.44E-05	4	730	6.00E-05	0.04
Isopentane	72.15	0.06530	9.05E-04	5		4.53E-03	3.31
Pentane	72.15	0.04620	6.40E-04	5		3.20E-03	2.34
Cyclopentane	70.1	0.00514	7.33E-05	5		3.70E-04	0.27
Hexane*	86.1	0.00925	1.07E-04	6		6.40E-04	0.47
Methyl Cyclopentane	84.16	0.00537	6.38E-05	6		3.80E-04	0.28
Cyclohexane	84.16	0.00267	3.17E-05	6		1.90E-04	0.14
Methyl Cyclohexane	98.19	0.00150	1.53E-05	7		1.10E-04	0.08
Benzene*	78.11	0.00389	4.98E-05	6		3.00E-04	0.22
Toluene*	92.14	0.00110	1.19E-05	7		8.00E-05	0.06
Mixed Xylenes*	106.16	0.000185	1.74E-06	8		1.00E-05	7.0E-03
Total		**0.14**	**1.91E-03**			**0.01**	**7.22**

[1] Provided by engineering company; generated by process modeling software.

Vent Gas HHV[2] (MMBtu/scf): 0.001235

Potential operation: 730 **hrs/yr**

Potential Emissions: Products of Combustion Gasoline Treater Flash Pot Vent

Pollutant	Emission Factor	Units	Hrs of Operation (hrs/yr)	Estimated (lb/hr)	(tpy)	Source of Emission Factor
CO_2	0.01	lb-mol/hr	730	0.44	0.16	40 CFR 98 Subpart W [1]
N_2O	0.0002	lb/MMBtu	730	1.8E-07	7.0E-08	40 CFR 98 Subpart W [2]
CO_2e				0.44	0.16	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO2. Emission factor is multiplied by molecular weight of CO2 (44.01 lb/lb-mol) to estimate emissions.

[2] Uses the vent gas heating value of 1.235 x 10^{-3} MMBtu/scf and 1 x 10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

Jefferson County NGL Fractionation Plant

EPN TO2 Emissions from Amine Unit Vent Gas

Control Efficiency

Compound	Rich Amine Flash Drum Emissions		Acid Gas Emissions		Total Uncontrolled Waste Gas Emissions	Molecular Weight	Total Moles of Hydrocarbon	Number of Carbon Atoms per Molecule	Moles of CO_2 from Combustion	Controlled Emissions	
	(lb-mol/hr)	(lb/hr)	(lb-mol/hr)	(lb/hr)	(lb/hr)	(lb/lb-mol)	(lb-mol/hr)		(lb-mol/hr)	(lb/hr)	(tpy)
carbon dioxide	5.0E-05	0.0022	21.2532	935.3551	935.36	44.01	-	-	-	935.36	4,096.88
Sulfur dioxide	-	-	-	-	-	64.06	-	-	-	0.46	2.01
hydrogen sulfide	0	0	0	0	0	34.08	0	-	-	0	0
Methyl mercaptan	7.0E-05	0.0034	0.0051	0.2444	0.25	48.11	0.0052	2	0.01	2.5E-04	1.1E-03
Ethyl mercaptan	2.0E-05	0.0012	0.0012	0.0770	0.08	62.13	0.0013	1	1.3E-03	7.8E-05	3.4E-04
n-Propyl mercaptan	5.0E-06	0.0004	0.0002	0.0152	0.02	76.16	0.0002	3	6.2E-04	1.6E-05	6.8E-05
n-Butyl mercaptan	1.0E-06	0.0001	2.0E-05	0.0018	1.9E-03	90.20	0.0000	4	8.4E-05	1.9E-06	8.3E-06
Carbon disulfide*	7.0E-06	0.0005	0.0001	0.0053	0.01	76.14	0.0001	1	7.7E-05	5.9E-06	2.6E-05
DMS	3.0E-06	0.0002	0.0003	0.0168	0.02	62.13	0.0003	2	5.5E-04	1.7E-05	7.4E-05
DMDS	1.0E-07	9.4E-06	1.0E-05	0.0009	9.5E-04	94.19	1.0E-05	2	2.0E-05	9.5E-07	4.2E-06
Carbonyl sulfide*	8.0E-06	0.0005	3.0E-05	0.0018	2.3E-03	60.07	3.8E-05	1	3.8E-05	2.3E-06	1.0E-05
Water	0.0200	0.3609	2.2044	39.7226	40.08	18.02	-	-	-	40.08	175.57
methane	0.2161	3.4661	0.0724	1.1607	4.63	16.04	0.2885	1	0.29	4.6E-03	0.02
ethane	2.1086	63.4059	1.0667	32.0763	95.48	30.07	3.1753	2	6.35	0.10	0.42
propane	0.4558	20.1021	0.1822	8.0359	28.14	44.10	0.6381	3	1.91	0.03	0.12
i-butane	0.0275	1.5977	0.0074	0.4289	2.03	58.12	0.0349	4	0.14	2.0E-03	8.9E-03
n-butane	0.0475	2.7578	0.0181	1.0520	3.81	58.12	0.0656	4	0.26	3.8E-03	0.02
i-pentane	0.0043	0.3117	0.0011	0.0772	0.39	72.15	0.0054	5	0.03	3.9E-04	1.7E-03
n-pentane	0.0035	0.2504	0.0010	0.0736	0.32	72.15	0.0045	5	0.02	3.2E-04	1.4E-03
Cyclopentane	0.0006	0.0393	0.0009	0.0638	0.10	70.10	0.0015	5	0.01	1.0E-04	4.5E-04
n-hexane*	0.0005	0.0431	0.0001	0.0103	0.05	86.10	0.0006	6	3.7E-03	5.3E-05	2.3E-04
Methylcyclopentane	0.0004	0.0362	0.0004	0.0362	0.07	84.16	0.0009	6	5.2E-03	7.2E-05	3.2E-04
Cyclohexane	0.0003	0.0261	0.0005	0.0379	0.06	84.16	0.0008	6	4.6E-03	6.4E-05	2.8E-04
Methylcyclohexane	0.0001	0.0137	0.0001	0.0108	0.02	98.19	0.0003	7	1.8E-03	2.5E-05	1.1E-04
Benzene*	0.0005	0.0422	0.0267	2.0824	2.12	78.11	0.0272	6	0.16	2.1E-03	9.3E-03
Toluene*	0.0001	0.0074	0.0080	0.7371	0.74	92.14	0.0081	7	0.06	7.4E-04	3.3E-03
Ethylbenzene*	0	0	0	0	0	106.17	0	8	0	0	0
o-xylene*	4.0E-06	0.0004	0.0005	0.0552	0.06	106.16	0.0005	8	4.2E-03	5.6E-05	2.4E-04
p-xylene*	4.0E-06	0.0004	0.0006	0.0594	0.06	106.16	0.0006	8	4.5E-03	6.0E-05	2.6E-04
m-xylene*	3.0E-06	0.0003	0.0004	0.0446	0.04	106.16	0.0004	8	3.4E-03	4.5E-05	2.0E-04
Methanol*	6.0E-05	0.0019	0.3585	11.4876	11.49	32.04	0.3586	1	0.36	0.01	0.05
2-Propanol	2.0E-06	0.0001	2.0E-05	0.0012	1.3E-03	60.11	2.2E-05	3	6.6E-05	1.3E-06	5.8E-06

Jefferson County NGL Fractionation Plant

EPN TO2 Emissions from Amine Unit Vent Gas

Control Efficiency

Compound	Rich Amine Flash Drum Emissions		Acid Gas Emissions		Total Uncontrolled Waste Gas Emissions	Molecular Weight	Total Moles of Hydrocarbon	Number of Carbon Atoms per Molecule	Moles of CO_2 from Combustion	Controlled Emissions	
	(lb-mol/hr)	(lb/hr)	(lb-mol/hr)	(lb/hr)	(lb/hr)	(lb/lb-mol)	(lb-mol/hr)		(lb-mol/hr)	(lb/hr)	(tpy)
DEAmine*	3.0E-08	3.6E-06	1.0E-17	1.2E-15	3.6E-06	119.16	3.0E-08	4	1.2E-07	3.6E-09	1.6E-08
Piperazine	0	0	0	0	0	86.14	0	4	0	0	0
Total	**2.89**	**92.47**	**25.21**	**1032.97**	**1125.44**		**4.62**		**9.63**	**976.05**	**4,275.11**
Total Hydrocarbons	**2.87**	**92.11**	**1.75**	**57.89**	**150.00**		**4.62**		**-**	**0.15**	**0.66**
Total HAPs	**1.2E-03**	**0.10**	**0.39**	**14.48**	**14.58**		**0.40**		**-**	**0.01**	**0.06**
Total VOC	**0.54**	**25.24**	**0.61**	**24.66**	**49.89**		**1.15**		**-**	**0.05**	**0.22**

*HAP

Vent Gas HHV[3] (MMBtu/scf): 0.001235

Potential operation: 8760 **hrs/yr**

Potential Emissions: Products of Combustion Amine Unit Vent Gas

Pollutant	Emission Factor	Units	Nominal Rating (MMBtu/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
CO_2	30.88	lb-mol/hr	-	8760	1359.19	5953.24	40 CFR 98 Subpart W [1]
CH_4	0.0046	lb/hr	-	8760	5.0E-03	0.02	40 CFR 98 Subpart W [2]
N_2O	0.0002	lb/MMBtu	-	8760	4.3E-04	1.9E-03	40 CFR 98 Subpart W [3]
CO_2e					1359.43	5954.29	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO_2. Emission factor is multiplied by molecular weight of CO_2 (44.01 lb/lb-mol) to estimate

[2] Assumes 98% destruction of methane. Remaining 2% of methane in waste gas is emitted as methane.

[3] Uses the vent gas heating value of 1.235×10^{-3} MMBtu/scf and 1×10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

Jefferson County NGL Fractionation Plant

EPN TE1 Fractionation Train 1 Trace Erase System Small Fraction of Emissions from Analyzer Sample Purges

Control Efficiency 98.0%

SourceDescription	Compound	Amount Released[1]				Density	Uncontrolled MSS Emissions	Molecular Weight	Moles of Hydrocarbon		Number of Carbon Moles	Moles of CO_2 from Combustion		Controlled Emissions	
		per Hour	Units	(lb/hr)	(lb/yr)	(lb/gal)	(lb/yr)	(lb/lb-mol)	(lb-mol/hr)	(lb-mol/yr)	(mol-C/lb-mol)	(lb-mol/hr)	(lb-mol/yr)	(lb/hr)	(tpy)
Feed to Deethanizer Analyzer Vent	Nitrogen	4.7E-08	lb-mol	1.3E-06	0.01	-	0.01	28.01	4.7E-08	4.2E-04	0	0	0	1.3E-06	5.8E-06
	Carbon Dioxide	3.6E-07	lb-mol	1.6E-05	0.14	-	0.14	44.01	3.6E-07	3.1E-03	-	-	-	1.6E-05	6.9E-05
	Methane	2.9E-06	lb-mol	4.6E-05	0.41	-	0.41	16.04	2.9E-06	0.03	1	2.9E-06	0.03	1.0E-06	4.0E-06
	Ethane	1.3E-04	lb-mol	4.0E-03	35.45	-	35.45	30.07	1.3E-04	1.18	2	2.7E-04	2.36	1.0E-04	4.0E-04
	Propane	7.6E-05	lb-mol	3.3E-03	29.34	-	29.34	44.10	7.6E-05	0.67	3	2.3E-04	2.00	1.0E-04	3.0E-04
	Isobutane	1.4E-05	lb-mol	8.4E-04	7.34	-	7.34	58.12	1.4E-05	0.13	4	5.8E-05	0.51	2.0E-05	1.0E-04
	n-Butane	2.6E-05	lb-mol	1.5E-03	13.06	-	13.06	58.12	2.6E-05	0.22	4	1.0E-04	0.90	3.0E-05	1.0E-04
	Isopentane	7.4E-06	lb-mol	5.3E-04	4.66	-	4.66	72.15	7.4E-06	0.06	5	3.7E-05	0.32	1.0E-05	5.0E-05
	Pentane	6.4E-06	lb-mol	4.6E-04	4.03	-	4.03	72.15	6.4E-06	0.06	5	3.2E-05	0.28	1.0E-05	4.0E-05
	Cyclopentane	5.2E-07	lb-mol	3.7E-05	0.32	-	0.32	70.10	5.2E-07	4.6E-03	5	2.6E-06	0.02	1.0E-06	3.0E-06
	Hexane*	3.8E-06	lb-mol	3.3E-04	2.86	-	2.86	86.10	3.8E-06	0.03	6	2.3E-05	0.20	1.0E-05	3.0E-05
	Methylcyclopentane	1.1E-06	lb-mol	9.0E-05	0.79	-	0.79	84.16	1.1E-06	0.01	6	6.4E-06	0.06	2.0E-06	1.0E-05
	Benzene*	5.5E-07	lb-mol	4.3E-05	0.37	-	0.37	78.11	5.5E-07	4.8E-03	6	3.3E-06	0.03	1.0E-06	4.0E-06
	Cyclohexane	6.9E-07	lb-mol	5.8E-05	0.51	-	0.51	84.16	6.9E-07	0.01	6	4.1E-06	0.04	1.0E-06	1.0E-05
	Methyl Cyclohexane	9.5E-07	lb-mol	9.3E-05	0.82	-	0.82	98.19	9.5E-07	0.01	7	6.6E-06	0.06	2.0E-06	1.0E-05
	Toluene*	4.5E-07	lb-mol	4.2E-05	0.36	-	0.36	92.14	4.5E-07	3.9E-03	7	3.2E-06	0.03	1.0E-06	4.0E-06
	Mixed Xylenes*	1.9E-07	lb-mol	2.0E-05	0.18	-	0.18	106.16	1.9E-07	1.7E-03	8	1.5E-06	0.01	4.0E-07	2.0E-06
	Carbon Disulfide*	2.4E-09	lb-mol	1.8E-07	0.00	-	0.00	76.14	2.4E-09	2.1E-05	1	2.4E-09	2.1E-05	4.0E-09	2.0E-08
Ethane Product Analyzer Vent	Nitrogen	2.4E-09	lb-mol	6.6E-08	0.00	-	0.00	28.01	2.4E-09	2.1E-05	0	0	0	6.6E-08	2.9E-07
	Carbon Dioxide	1.4E-07	lb-mol	6.3E-06	0.05	-	0.05	44.01	1.4E-07	1.2E-03	-	-	-	6.3E-06	2.7E-05
	Methane	7.0E-06	lb-mol	1.1E-04	0.98	-	0.98	16.04	7.0E-06	0.06	1	7.0E-06	0.06	2.0E-06	1.0E-05
	Ethane	2.3E-04	lb-mol	7.0E-03	61.25	-	61.25	30.07	2.3E-04	2.04	2	4.7E-04	4.07	1.0E-04	1.0E-03
	Propane	1.1E-06	lb-mol	5.0E-05	0.44	-	0.44	44.10	1.1E-06	0.01	3	3.4E-06	0.03	5.0E-05	2.2E-04
Deethanizer Bottoms Analyzer Vent	Ethane	7.1E-07	lb-mol	2.1E-05	0.19	-	0.19	30.07	7.1E-07	0.01	2	1.4E-06	0.01	2.1E-05	9.4E-05
	Propane	1.4E-04	lb-mol	6.0E-03	52.31	-	52.31	44.10	1.4E-04	1.19	3	4.1E-04	3.56	1.0E-04	1.0E-03
	Isobutane	2.5E-05	lb-mol	1.4E-03	12.63	-	12.63	58.12	2.5E-05	0.22	4	9.9E-05	0.87	3.0E-05	1.0E-04
	n-Butane	4.4E-05	lb-mol	2.6E-03	22.47	-	22.47	58.12	4.4E-05	0.39	4	1.8E-04	1.55	1.0E-04	2.0E-04
	Isopentane	1.3E-05	lb-mol	9.1E-04	8.00	-	8.00	72.15	1.3E-05	0.11	5	6.3E-05	0.55	2.0E-05	1.0E-04
	Pentane	1.1E-05	lb-mol	7.9E-04	6.94	-	6.94	72.15	1.1E-05	0.10	5	5.5E-05	0.48	2.0E-05	1.0E-04
	Cyclopentane	8.8E-07	lb-mol	6.2E-05	0.54	-	0.54	70.10	8.8E-07	0.01	5	4.4E-06	0.04	1.0E-06	5.0E-06
	Hexane*	6.5E-06	lb-mol	5.6E-04	4.92	-	4.92	86.10	6.5E-06	0.06	6	3.9E-05	0.34	1.0E-05	5.0E-05
	Methylcyclopentane	1.8E-06	lb-mol	1.6E-04	1.36	-	1.36	84.16	1.8E-06	0.02	6	1.1E-05	0.10	3.0E-06	1.0E-05
	Benzene*	9.2E-07	lb-mol	7.2E-05	0.63	-	0.63	78.11	9.2E-07	0.01	6	5.5E-06	0.05	1.0E-06	1.0E-05
	Cyclohexane	1.2E-06	lb-mol	9.8E-05	0.86	-	0.86	84.16	1.2E-06	0.01	6	7.0E-06	0.06	2.0E-06	1.0E-05
	Methyl Cyclohexane	1.6E-06	lb-mol	1.6E-04	1.41	-	1.41	98.19	1.6E-06	0.01	7	1.1E-05	0.10	3.0E-06	1.0E-05
	Toluene*	7.8E-07	lb-mol	7.2E-05	0.63	-	0.63	92.14	7.8E-07	0.01	7	5.5E-06	0.05	1.0E-06	1.0E-05
	Mixed Xylenes*	3.3E-07	lb-mol	3.5E-05	0.31	-	0.31	106.16	3.3E-07	2.9E-03	8	2.7E-06	0.02	1.0E-06	3.0E-06
	Mercaptans	2.4E-08	lb-mol	1.5E-06	0.01	-	0.01	62.13	2.4E-08	2.1E-04	2	4.7E-08	4.2E-04	3.0E-08	1.0E-07
	Carbon Disulfide*	4.7E-09	lb-mol	3.6E-07	0.00	-	0.00	76.14	4.7E-09	4.2E-05	1	4.7E-09	4.2E-05	1.0E-08	3.0E-08
	Dimethyl Sulfide	2.4E-09	lb-mol	1.5E-07	0.00	-	0.00	62.13	2.4E-09	2.1E-05	2	4.7E-09	4.2E-05	3.0E-09	1.0E-08

Jefferson County NGL Fractionation Plant

EPN TE1 Fractionation Train 1 Trace Erase System Small Fraction of Emissions from Analyzer Sample Purges

Control Efficiency 98.0%

SourceDescription	**Compound**	**Amount Released[1]**				**Density**	**Uncontrolled MSS Emissions**	**Molecular Weight**	**Moles of Hydrocarbon**		**Number of Carbon Moles**	**Moles of CO_2 from Combustion**		**Controlled Emissions**	
		per Hour	**Units**	**(lb/hr)**	**(lb/yr)**	**(lb/gal)**	**(lb/yr)**	**(lb/lb-mol)**	**(lb-mol/hr)**	**(lb-mol/yr)**	**(mol-C/lb-mol)**	**(lb-mol/hr)**	**(lb-mol/yr)**	**(lb/hr)**	**(tpy)**
Depropanizer Product Analyzer Vent	Ethane	1.2E-06	lb-mol	3.7E-05	0.32	-	0.32	30.07	1.2E-06	0.01	2	2.5E-06	0.02	1.0E-06	3.0E-06
	Propane	2.3E-04	lb-mol	1.0E-02	90.76	-	90.76	44.10	2.3E-04	2.06	3	7.0E-04	6.17	2.0E-04	9.0E-04
	Isobutane	1.0E-06	lb-mol	5.8E-05	0.51	-	0.51	58.12	1.0E-06	0.01	4	4.0E-06	0.03	1.0E-06	1.0E-05
Debutanizer Overheads Analyzer Vent	Propane	8.3E-07	lb-mol	3.7E-05	0.32	-	0.32	44.10	8.3E-07	0.01	3	2.5E-06	0.02	1.0E-06	3.0E-06
	Isobutane	8.7E-05	lb-mol	5.1E-03	44.47	-	44.47	58.12	8.7E-05	0.77	4	3.5E-04	3.06	1.0E-04	4.0E-04
	n-Butane	1.5E-04	lb-mol	8.8E-03	77.32	-	77.32	58.12	1.5E-04	1.33	4	6.1E-04	5.32	2.0E-04	1.0E-03
	Isopentane	8.1E-07	lb-mol	5.8E-05	0.51	-	0.51	72.15	8.1E-07	0.01	5	4.0E-06	0.04	1.0E-06	1.0E-05
	Pentane	2.4E-08	lb-mol	1.7E-06	0.01	-	0.01	72.15	2.4E-08	2.1E-04	5	1.2E-07	1.0E-03	3.0E-08	1.0E-07
	Mercaptans	4.7E-08	lb-mol	2.9E-06	0.03	-	0.03	62.13	4.7E-08	4.2E-04	2	9.5E-08	8.3E-04	1.0E-07	3.0E-07
	Carbon Disulfide*	9.5E-09	lb-mol	7.2E-07	0.01	-	0.01	76.14	9.5E-09	8.3E-05	1	9.5E-09	8.3E-05	1.0E-08	1.0E-07
Deisobutanizer Overheads Analyzer Vent	Propane	2.3E-06	lb-mol	9.9E-05	0.87	-	0.87	44.10	2.3E-06	0.02	3	6.8E-06	0.06	2.0E-06	1.0E-05
	Isobutane	2.3E-04	lb-mol	1.3E-02	117.70	-	117.70	58.12	2.3E-04	2.03	4	9.2E-04	8.10	3.0E-04	1.0E-03
	n-Butane	3.7E-06	lb-mol	2.1E-04	1.87	-	1.87	58.12	3.7E-06	0.03	4	1.5E-05	0.13	4.0E-06	2.0E-05
	Mercaptans	4.7E-08	lb-mol	2.9E-06	0.03	-	0.03	62.13	4.7E-08	4.2E-04	2	9.5E-08	8.3E-04	1.0E-07	3.0E-07
n-Butane Product Analyzer Vent	Isobutane	3.4E-06	lb-mol	2.0E-04	1.75	-	1.75	58.12	3.4E-06	0.03	4	1.4E-05	0.12	4.0E-06	2.0E-05
	n-Butane	2.3E-04	lb-mol	1.4E-02	118.44	-	118.44	58.12	2.3E-04	2.04	4	9.3E-04	8.15	3.0E-04	1.0E-03
	Isopentane	1.2E-06	lb-mol	8.9E-05	0.78	-	0.78	72.15	1.2E-06	0.01	5	6.2E-06	0.05	2.0E-06	1.0E-05
	Pentane	4.7E-08	lb-mol	3.4E-06	0.03	-	0.03	72.15	4.7E-08	4.2E-04	5	2.4E-07	2.1E-03	1.0E-07	3.0E-07
	Mercaptans	2.4E-08	lb-mol	1.5E-06	0.01	-	0.01	62.13	2.4E-08	2.1E-04	2	4.7E-08	4.2E-04	3.0E-08	1.0E-07
	Carbon Disulfide*	1.4E-08	lb-mol	1.1E-06	0.01	-	0.01	76.14	1.4E-08	1.2E-04	1	1.4E-08	1.2E-04	2.0E-08	1.0E-07
TOTAL				**0.08**	**732.33**		**732.33**		**1.7E-03**	**15.00**	**-**	**5.7E-03**	**50.06**	**1.9E-03**	**0.01**

[1] Annual rates conservatively assume the hourly vent rate is continuous for the purpose of estimating annual emissions. However, these vents are intermittent and will likely not emit at the hourly rate every hour of the year.

Vent Gas HHV[3] (MMBtu/scf): 0.001235

Potential operation: 8760 hr/yr

Potential Emissions: Products of Combustion Small Fraction of Sample Purges

Pollutant	Emission Factor		Estimated Emissions[1]		Source of Emission Factor
	EF	Units	(lb/hr)	(tpy)	
CO_2	0.0057	lb-mol/hr	0.25	1.10	40 CFR 98 Subpart W[1]
CH_4	0.0000002	lb-mol/hr	3.0E-06	1.0E-05	40 CFR 98 Subpart W[2]
N_2O	0.0002	lb/MMBtu	1.6E-07	7.0E-07	40 CFR 98 Subpart W[3]
CO_2e	-	-	0.25	1.10	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO_2. Emission factor is multiplied by molecular weight of CO_2 (44.01 lb/lb-mol) to estimate emissions.

[2] Assumes 98% destruction of methane. Remaining 2% of methane in waste gas is emitted as methane.

[3] Uses the vent gas heating value of 1.235 x 10^{-3} MMBtu/scf and 1 x 10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

Jefferson County NGL Fractionation Plant

EPN TE2 Fractionation Train 2 Trace Erase System Small Fraction of Emissions from Analyzer Sample Purges

Control Efficiency 98.0%

SourceDescription	Compound	Amount Released[1]				Density	Uncontrolled MSS Emissions	Molecular Weight	Moles of Hydrocarbon		Number of Carbon Moles	Moles of CO_2 from Combustion		Controlled Emissions	
		per Hour	Units	(lb/hr)	(lb/yr)	(lb/gal)	(lb/yr)	(lb/lb-mol)	(lb-mol/hr)	(lb-mol/yr)	(mol-C/lb-mol)	(lb-mol/hr)	(lb-mol/yr)	(lb/hr)	(tpy)
Feed to Deethanizer Analyzer Vent	Nitrogen	4.7E-08	lb-mol	1.3E-06	0.01	-	0.01	28.01	4.7E-08	4.2E-04	0	0	0	1.3E-06	5.8E-06
	Carbon Dioxide	3.6E-07	lb-mol	1.6E-05	0.14	-	0.14	44.01	3.6E-07	3.1E-03	-	-	-	1.6E-05	6.9E-05
	Methane	2.9E-06	lb-mol	4.6E-05	0.41	-	0.41	16.04	2.9E-06	0.03	1	2.9E-06	0.03	1.0E-06	4.0E-06
	Ethane	1.3E-04	lb-mol	4.0E-03	35.45	-	35.45	30.07	1.3E-04	1.18	2	2.7E-04	2.36	1.0E-04	4.0E-04
	Propane	7.6E-05	lb-mol	3.3E-03	29.34	-	29.34	44.10	7.6E-05	0.67	3	2.3E-04	2.00	1.0E-04	3.0E-04
	Isobutane	1.4E-05	lb-mol	8.4E-04	7.34	-	7.34	58.12	1.4E-05	0.13	4	5.8E-05	0.51	2.0E-05	1.0E-04
	n-Butane	2.6E-05	lb-mol	1.5E-03	13.06	-	13.06	58.12	2.6E-05	0.22	4	1.0E-04	0.90	3.0E-05	1.0E-04
	Isopentane	7.4E-06	lb-mol	5.3E-04	4.66	-	4.66	72.15	7.4E-06	0.06	5	3.7E-05	0.32	1.0E-05	5.0E-05
	Pentane	6.4E-06	lb-mol	4.6E-04	4.03	-	4.03	72.15	6.4E-06	0.06	5	3.2E-05	0.28	1.0E-05	4.0E-05
	Cyclopentane	5.2E-07	lb-mol	3.7E-05	0.32	-	0.32	70.10	5.2E-07	4.6E-03	5	2.6E-06	0.02	1.0E-06	3.0E-06
	Hexane*	3.8E-06	lb-mol	3.3E-04	2.86	-	2.86	86.10	3.8E-06	0.03	6	2.3E-05	0.20	1.0E-05	3.0E-05
	Methylcyclopentane	1.1E-06	lb-mol	9.0E-05	0.79	-	0.79	84.16	1.1E-06	0.01	6	6.4E-06	0.06	2.0E-06	1.0E-05
	Benzene*	5.5E-07	lb-mol	4.3E-05	0.37	-	0.37	78.11	5.5E-07	4.8E-03	6	3.3E-06	0.03	1.0E-06	4.0E-06
	Cyclohexane	6.9E-07	lb-mol	5.8E-05	0.51	-	0.51	84.16	6.9E-07	0.01	6	4.1E-06	0.04	1.0E-06	1.0E-05
	Methyl Cyclohexane	9.5E-07	lb-mol	9.3E-05	0.82	-	0.82	98.19	9.5E-07	0.01	7	6.6E-06	0.06	2.0E-06	1.0E-05
	Toluene*	4.5E-07	lb-mol	4.2E-05	0.36	-	0.36	92.14	4.5E-07	3.9E-03	7	3.2E-06	0.03	1.0E-06	4.0E-06
	Mixed Xylenes*	1.9E-07	lb-mol	2.0E-05	0.18	-	0.18	106.16	1.9E-07	1.7E-03	8	1.5E-06	0.01	4.0E-07	2.0E-06
	Carbon Disulfide*	2.4E-09	lb-mol	1.8E-07	0.00	-	0.00	76.14	2.4E-09	2.1E-05	1	2.4E-09	2.1E-05	4.0E-09	2.0E-08
Ethane Product Analyzer Vent	Nitrogen	2.4E-09	lb-mol	6.6E-08	0.00	-	0.00	28.01	2.4E-09	2.1E-05	0	0	0	6.6E-08	2.9E-07
	Carbon Dioxide	1.4E-07	lb-mol	6.3E-06	0.05	-	0.05	44.01	1.4E-07	1.2E-03	-	-	-	6.3E-06	2.7E-05
	Methane	7.0E-06	lb-mol	1.1E-04	0.98	-	0.98	16.04	7.0E-06	0.06	1	7.0E-06	0.06	2.0E-06	1.0E-05
	Ethane	2.3E-04	lb-mol	7.0E-03	61.25	-	61.25	30.07	2.3E-04	2.04	2	4.7E-04	4.07	1.0E-04	1.0E-03
	Propane	1.1E-06	lb-mol	5.0E-05	0.44	-	0.44	44.10	1.1E-06	0.01	3	3.4E-06	0.03	5.0E-05	2.2E-04
Deethanizer Bottoms Analyzer Vent	Ethane	7.1E-07	lb-mol	2.1E-05	0.19	-	0.19	30.07	7.1E-07	0.01	2	1.4E-06	0.01	2.1E-05	9.4E-05
	Propane	1.4E-04	lb-mol	6.0E-03	52.31	-	52.31	44.10	1.4E-04	1.19	3	4.1E-04	3.56	1.0E-04	1.0E-03
	Isobutane	2.5E-05	lb-mol	1.4E-03	12.63	-	12.63	58.12	2.5E-05	0.22	4	9.9E-05	0.87	3.0E-05	1.0E-04
	n-Butane	4.4E-05	lb-mol	2.6E-03	22.47	-	22.47	58.12	4.4E-05	0.39	4	1.8E-04	1.55	1.0E-04	2.0E-04
	Isopentane	1.3E-05	lb-mol	9.1E-04	8.00	-	8.00	72.15	1.3E-05	0.11	5	6.3E-05	0.55	2.0E-05	1.0E-04
	Pentane	1.1E-05	lb-mol	7.9E-04	6.94	-	6.94	72.15	1.1E-05	0.10	5	5.5E-05	0.48	2.0E-05	1.0E-04
	Cyclopentane	8.8E-07	lb-mol	6.2E-05	0.54	-	0.54	70.10	8.8E-07	0.01	5	4.4E-06	0.04	1.0E-06	5.0E-06
	Hexane*	6.5E-06	lb-mol	5.6E-04	4.92	-	4.92	86.10	6.5E-06	0.06	6	3.9E-05	0.34	1.0E-05	5.0E-05
	Methylcyclopentane	1.8E-06	lb-mol	1.6E-04	1.36	-	1.36	84.16	1.8E-06	0.02	6	1.1E-05	0.10	3.0E-06	1.0E-05
	Benzene*	9.2E-07	lb-mol	7.2E-05	0.63	-	0.63	78.11	9.2E-07	0.01	6	5.5E-06	0.05	1.0E-06	1.0E-05
	Cyclohexane	1.2E-06	lb-mol	9.8E-05	0.86	-	0.86	84.16	1.2E-06	0.01	6	7.0E-06	0.06	2.0E-06	1.0E-05
	Methyl Cyclohexane	1.6E-06	lb-mol	1.6E-04	1.41	-	1.41	98.19	1.6E-06	0.01	7	1.1E-05	0.10	3.0E-06	1.0E-05
	Toluene*	7.8E-07	lb-mol	7.2E-05	0.63	-	0.63	92.14	7.8E-07	0.01	7	5.5E-06	0.05	1.0E-06	1.0E-05
	Mixed Xylenes*	3.3E-07	lb-mol	3.5E-05	0.31	-	0.31	106.16	3.3E-07	2.9E-03	8	2.7E-06	0.02	1.0E-06	3.0E-06
	Mercaptans	2.4E-08	lb-mol	1.5E-06	0.01	-	0.01	62.13	2.4E-08	2.1E-04	2	4.7E-08	4.2E-04	3.0E-08	1.0E-07
	Carbon Disulfide*	4.7E-09	lb-mol	3.6E-07	0.00	-	0.00	76.14	4.7E-09	4.2E-05	1	4.7E-09	4.2E-05	1.0E-08	3.0E-08
	Dimethyl Sulfide	2.4E-09	lb-mol	1.5E-07	0.00	-	0.00	62.13	2.4E-09	2.1E-05	2	4.7E-09	4.2E-05	3.0E-09	1.0E-08

Jefferson County NGL Fractionation Plant

EPN TE2 Fractionation Train 2 Trace Erase System Small Fraction of Emissions from Analyzer Sample Purges

Control Efficiency 98.0%

SourceDescription	Compound	Amount Released[1]				Density	Uncontrolled MSS Emissions	Molecular Weight	Moles of Hydrocarbon		Number of Carbon Moles	Moles of CO_2 from Combustion		Controlled Emissions	
		per Hour	Units	(lb/hr)	(lb/yr)	(lb/gal)	(lb/yr)	(lb/lb-mol)	(lb-mol/hr)	(lb-mol/yr)	(mol-C/lb-mol)	(lb-mol/hr)	(lb-mol/yr)	(lb/hr)	(tpy)
Depropanizer Product Analyzer Vent	Ethane	1.2E-06	lb-mol	3.7E-05	0.32	-	0.32	30.07	1.2E-06	0.01	2	2.5E-06	0.02	1.0E-06	3.0E-06
	Propane	2.3E-04	lb-mol	1.0E-02	90.76	-	90.76	44.10	2.3E-04	2.06	3	7.0E-04	6.17	2.0E-04	9.0E-04
	Isobutane	1.0E-06	lb-mol	5.8E-05	0.51	-	0.51	58.12	1.0E-06	0.01	4	4.0E-06	0.03	1.0E-06	1.0E-05
Debutanizer Overheads Analyzer Vent	Propane	8.3E-07	lb-mol	3.7E-05	0.32	-	0.32	44.10	8.3E-07	0.01	3	2.5E-06	0.02	1.0E-06	3.0E-06
	Isobutane	8.7E-05	lb-mol	5.1E-03	44.47	-	44.47	58.12	8.7E-05	0.77	4	3.5E-04	3.06	1.0E-04	4.0E-04
	n-Butane	1.5E-04	lb-mol	8.8E-03	77.32	-	77.32	58.12	1.5E-04	1.33	4	6.1E-04	5.32	2.0E-04	1.0E-03
	Isopentane	8.1E-07	lb-mol	5.8E-05	0.51	-	0.51	72.15	8.1E-07	0.01	5	4.0E-06	0.04	1.0E-06	1.0E-05
	Pentane	2.4E-08	lb-mol	1.7E-06	0.01	-	0.01	72.15	2.4E-08	2.1E-04	5	1.2E-07	1.0E-03	3.0E-08	1.0E-07
	Mercaptans	4.7E-08	lb-mol	2.9E-06	0.03	-	0.03	62.13	4.7E-08	4.2E-04	2	9.5E-08	8.3E-04	1.0E-07	3.0E-07
	Carbon Disulfide*	9.5E-09	lb-mol	7.2E-07	0.01	-	0.01	76.14	9.5E-09	8.3E-05	1	9.5E-09	8.3E-05	1.0E-08	1.0E-07
Deisobutanizer Overheads Analyzer Vent	Propane	2.3E-06	lb-mol	9.9E-05	0.87	-	0.87	44.10	2.3E-06	0.02	3	6.8E-06	0.06	2.0E-06	1.0E-05
	Isobutane	2.3E-04	lb-mol	1.3E-02	117.70	-	117.70	58.12	2.3E-04	2.03	4	9.2E-04	8.10	3.0E-04	1.0E-03
	n-Butane	3.7E-06	lb-mol	2.1E-04	1.87	-	1.87	58.12	3.7E-06	0.03	4	1.5E-05	0.13	4.0E-06	2.0E-05
	Mercaptans	4.7E-08	lb-mol	2.9E-06	0.03	-	0.03	62.13	4.7E-08	4.2E-04	2	9.5E-08	8.3E-04	1.0E-07	3.0E-07
n-Butane Product Analyzer Vent	Isobutane	3.4E-06	lb-mol	2.0E-04	1.75	-	1.75	58.12	3.4E-06	0.03	4	1.4E-05	0.12	4.0E-06	2.0E-05
	n-Butane	2.3E-04	lb-mol	1.4E-02	118.44	-	118.44	58.12	2.3E-04	2.04	4	9.3E-04	8.15	3.0E-04	1.0E-03
	Isopentane	1.2E-06	lb-mol	8.9E-05	0.78	-	0.78	72.15	1.2E-06	0.01	5	6.2E-06	0.05	2.0E-06	1.0E-05
	Pentane	4.7E-08	lb-mol	3.4E-06	0.03	-	0.03	72.15	4.7E-08	4.2E-04	5	2.4E-07	2.1E-03	1.0E-07	3.0E-07
	Mercaptans	2.4E-08	lb-mol	1.5E-06	0.01	-	0.01	62.13	2.4E-08	2.1E-04	2	4.7E-08	4.2E-04	3.0E-08	1.0E-07
	Carbon Disulfide*	1.4E-08	lb-mol	1.1E-06	0.01	-	0.01	76.14	1.4E-08	1.2E-04	1	1.4E-08	1.2E-04	2.0E-08	1.0E-07
TOTAL				**0.08**	**732.33**		**732.33**		**1.7E-03**	**15.00**	**-**	**5.7E-03**	**50.06**	**1.9E-03**	**0.01**

[1] Annual rates conservatively assume the hourly vent rate is continuous for the purpose of estimating annual emissions. However, these vents are intermittent and will likely not emit at the hourly rate every hour of the year.

Vent Gas HHV[3] (MMBtu/scf): 0.001235

Potential operation: 8760 hr/yr

Potential Emissions: Products of Combustion Small Fraction of Sample Purges

Pollutant	Emission Factor		Estimated Emissions[1]		Source of Emission Factor
	EF	Units	(lb/hr)	(tpy)	
CO_2	0.0057	lb-mol/hr	0.25	1.10	40 CFR 98 Subpart W [1]
CH_4	0.0000002	lb-mol/hr	3.0E-06	1.0E-05	40 CFR 98 Subpart W [2]
N_2O	0.0002	lb/MMBtu	1.6E-07	7.0E-07	40 CFR 98 Subpart W [3]
CO_2e	-	-	0.25	1.10	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO_2. Emission factor is multiplied by molecular weight of CO_2 (44.01 lb/lb-mol) to estimate emissions.

[2] Assumes 98% destruction of methane. Remaining 2% of methane in waste gas is emitted as methane.

[3] Uses the vent gas heating value of 1.235 x 10^{-3} MMBtu/scf and 1 x 10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs:FUG1 & FUG2
Total Emissions per Train

Component	Stream 101		Stream 114		Stream 114/118 Mix		Stream 116	Stream 118	Stream 200		Stream	Stream	Stream 205	Stream 300		Stream 301	Stream 302		Stream 304		Stream 400		Stream 402		Stream 403		Stream 404		Stream 500	Stream 501	Stream 502	Stream 504		Stream 700		Stream 701	Stream 05032	Stream 55015		Stream 55030		Stream 55032a	Stream 55038	Stream 55062	Natural Gas Fuel	Hourly	Annual
	gas (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	light liquid (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	light liquid (lb/hr)	light liquid (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	light liquid (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	gas (lb/hr)	Emissions (lb/hr)	Emissions (tpy)
Nitrogen	2.0E-06	4.7E-06	7.5E-06	1.7E-05	0	0	7.4E-06	0	8.3E-06	6.5E-06	1.1E-05	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.0E-05	2.6E-08	0	0	1.5E-08	1.2E-09	0	9.4E-12	0	1.1E-03	1.2E-03	0.01
Carbon Dioxide	2.3E-05	5.5E-05	5.9E-06	1.4E-05	3.0E-05	3.7E-06	5.8E-06	2.0E-05	1.3E-05	1.0E-05	1.7E-05	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8.1E-06	2.5E-04	1.1E-05	3.8E-04	1.0E-03	8.2E-05	0.03	2.4E-05	5.3E-07	8.2E-03	0.04	0.17
Methane	6.9E-05	1.6E-04	2.6E-04	6.1E-04	2.4E-05	3.0E-06	2.6E-04	0	2.2E-04	1.7E-04	2.9E-04	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2.9E-04	7.5E-07	0	0	9.2E-07	7.4E-08	3.6E-05	1.1E-09	8.4E-04	0.22	0.22	0.96
Ethane	4.3E-03	0.01	0.02	0.04	1.5E-03	1.8E-04	0.02	0	0.03	0.02	0.04	3.3E-05	7.4E-05	8.7E-05	3.2E-05	8.1E-06	0	0	2.8E-04	1.2E-04	0	0	0	0	0	0	0	0	0	0	0	0	0	5.0E-05	5.9E-05	0.02	1.6E-05	0	0	2.6E-05	2.1E-06	9.9E-04	3.4E-08	0.02	5.8E-03	0.22	0.95
Propane	5.0E-03	0.01	0.02	0.04	1.7E-03	2.1E-04	0.02	0	2.1E-04	1.6E-04	2.7E-04	9.4E-03	0.02	0.02	8.8E-03	2.3E-03	4.3E-06	3.1E-05	0.08	0.03	5.9E-05	3.0E-07	0	0	0	0	1.3E-04	4.7E-04	4.3E-04	1.4E-04	0	0	0	8.1E-04	9.6E-04	1.3E-04	4.6E-06	0	0	6.4E-06	5.1E-07	2.5E-04	6.5E-09	4.9E-03	4.3E-04	0.29	1.25
Propylene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.06	0.07	0	-	-	-	-	-	-	-	-	-	0.12	0.55
Isobutane	1.2E-03	3.0E-03	4.7E-03	0.01	4.3E-04	5.2E-05	4.7E-03	0	0	0	0	2.4E-03	1.2E-04	1.4E-04	4.9E-05	1.3E-05	5.9E-04	4.3E-03	4.4E-04	1.8E-04	8.3E-03	4.3E-05	0	0	9.5E-05	3.4E-04	0.02	0.06	0.06	0.02	3.2E-04	0	0	3.2E-04	3.8E-04	0	3.3E-07	0	0	3.4E-07	2.7E-08	1.3E-05	2.2E-10	3.9E-04	8.1E-05	0.20	0.89
n-Butane	2.2E-03	5.3E-03	8.4E-03	0.02	7.6E-04	9.4E-05	8.4E-03	0	0	0	0	4.2E-03	0	0	0	0	1.1E-03	7.8E-03	0	0	0.02	7.8E-05	8.7E-06	2.3E-05	6.4E-03	0.02	2.7E-04	1.0E-03	9.3E-04	3.1E-04	0.02	9.7E-05	9.5E-05	0	0	0	6.2E-07	0	0	8.4E-07	6.7E-08	3.2E-05	8.1E-10	6.7E-04	8.1E-05	0.13	0.56
Isopentane	7.9E-04	1.9E-03	3.0E-03	7.0E-03	2.7E-04	3.3E-05	3.0E-03	0	0	0	0	1.5E-03	0	0	0	0	3.8E-04	2.8E-03	0	0	9.9E-05	5.1E-07	1.8E-03	4.8E-03	4.2E-05	1.5E-04	0	0	0	0	1.4E-04	0.02	0.02	0	0	0	6.3E-08	0	0	6.1E-08	4.9E-09	2.4E-06	3.0E-11	7.6E-05	-	0.07	0.29
Pentane	6.8E-04	1.6E-03	2.6E-03	6.0E-03	2.3E-04	2.9E-05	2.6E-03	0	0	0	0	1.3E-03	0	0	0	0	3.3E-04	2.4E-03	0	0	2.9E-06	1.5E-08	1.6E-03	4.2E-03	1.6E-06	5.8E-06	0	0	0	0	5.4E-06	0.02	0.02	0	0	0	5.3E-08	0	0	5.9E-08	4.7E-09	2.3E-06	3.5E-11	6.1E-05	-	0.06	0.26
Cyclopentane	5.4E-05	1.3E-04	2.1E-04	4.8E-04	1.9E-05	2.3E-06	2.0E-04	0	0	0	0	1.0E-04	0	0	0	0	2.6E-05	1.9E-04	0	0	0	0	1.2E-04	3.3E-04	0	0	0	0	0	0	0	1.4E-03	1.4E-03	0	0	0	1.7E-08	0	0	5.1E-08	4.1E-09	2.0E-06	1.6E-10	9.5E-06	-	4.6E-03	0.02
Hexane*	4.8E-04	1.2E-03	1.8E-03	4.3E-03	1.7E-04	2.0E-05	1.8E-03	0	0	0	0	9.2E-04	0	0	0	0	2.4E-04	1.7E-03	0	0	0	0	1.1E-03	3.0E-03	0	0	0	0	0	0	0	0.01	0.01	0	0	0	8.6E-09	0	0	8.0E-09	6.4E-10	3.2E-07	2.7E-12	1.0E-05	-	0.04	0.18
Methylcyclopentane	1.3E-04	3.2E-04	5.1E-04	1.2E-03	4.7E-05	5.7E-06	5.0E-04	0	0	0	0	2.6E-04	0	0	0	0	6.6E-05	4.7E-04	0	0	0	0	3.1E-04	8.3E-04	0	0	0	0	0	0	0	3.4E-03	3.4E-03	0	0	0	1.2E-08	0	0	2.9E-08	2.3E-09	1.1E-06	4.7E-11	8.8E-06	-	0.01	0.05
Cyclohexane	8.6E-05	2.0E-04	3.3E-04	7.6E-04	3.0E-05	3.7E-06	3.2E-04	0	0	0	0	1.6E-04	0	0	0	0	4.1E-05	3.0E-04	0	0	0	0	2.0E-04	5.2E-04	0	0	0	0	0	0	0	2.2E-03	2.1E-03	0	0	0	1.0E-08	0	0	3.0E-08	2.4E-09	1.2E-06	8.2E-11	6.3E-06	-	0.01	0.03
Methyl Cyclohexane	1.4E-04	3.3E-04	5.2E-04	1.2E-03	4.7E-05	5.7E-06	5.2E-04	0	0	0	0	2.6E-04	0	0	0	0	6.7E-05	4.8E-04	0	0	0	0	3.2E-04	8.5E-04	0	0	0	0	0	0	0	3.5E-03	3.5E-03	0	0	0	4.0E-09	0	0	8.7E-09	7.0E-10	3.3E-07	1.2E-11	3.3E-06	-	0.01	0.05
Benzene*	6.3E-05	1.5E-04	2.4E-04	5.6E-04	2.2E-05	2.8E-06	2.4E-04	0	0	0	0	1.2E-04	0	0	0	0	3.1E-05	2.2E-04	0	0	0	0	1.5E-04	3.9E-04	0	0	0	0	0	0	0	1.6E-03	1.6E-03	0	0	0	3.5E-07	0	0	1.7E-06	1.4E-07	6.4E-05	1.5E-07	1.0E-05	4.7E-04	0.01	0.03
Toluene*	6.1E-05	1.5E-04	2.3E-04	5.4E-04	2.0E-05	2.5E-06	2.3E-04	0	0	0	0	1.2E-04	0	0	0	0	3.0E-05	2.2E-04	0	0	0	0	1.4E-04	3.8E-04	0	0	0	0	0	0	0	1.6E-03	1.6E-03	0	0	0	1.2E-07	0	0	6.0E-07	4.8E-08	2.3E-05	4.0E-08	1.8E-06	1.3E-04	0.01	0.02
Ethylbenzene*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	1.0E-05	1.0E-05	4.6E-05
o-Xylene*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.2E-09	0	0	4.5E-08	3.6E-09	1.7E-06	3.7E-09	1.0E-07	-	1.9E-06	8.2E-06
p-Xylene*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9E-09	0	0	4.9E-08	3.9E-09	1.8E-06	4.0E-09	1.0E-07	1.8E-05	2.0E-05	8.9E-05
m-Xylene*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.3E-09	0	0	3.6E-08	2.9E-09	1.4E-06	2.9E-09	7.7E-08	-	1.5E-06	6.6E-06
Mixed Xylenes*	3.0E-05	7.1E-05	1.1E-04	2.6E-04	1.1E-05	1.4E-06	1.1E-04	0	0	0	0	5.8E-05	0	0	0	0	1.5E-05	1.1E-04	0	0	0	0	7.2E-05	1.9E-04	0	0	0	0	0	0	0	8.0E-04	7.8E-04	0	0	0	-	-	-	-	-	-	-	-	-	2.6E-03	0.01
Hydrogen Sulfide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	-	0.0E+00	0.0E+00
Methyl Mercaptan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.0E-08	0	0	2.1E-07	1.7E-08	7.5E-06	3.4E-08	8.2E-07	-	8.7E-06	3.8E-05
Ethyl Mercaptan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.3E-08	0	0	6.4E-08	5.2E-09	2.4E-06	9.1E-09	3.0E-07	-	2.8E-06	1.2E-05
n-Propyl Mercaptan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6E-09	0	0	1.3E-08	1.0E-09	4.7E-07	1.5E-09	9.2E-08	-	5.8E-07	2.5E-06
n-Butyl Mercaptan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.5E-10	0	0	1.2E-09	9.5E-11	5.6E-08	6.6E-11	2.2E-08	-	7.9E-08	3.5E-07
Carbon Disulfide*	2.7E-07	6.4E-07	1.0E-06	2.4E-06	0	0	1.0E-06	0	0	0	0	5.9E-07	0	0	0	0	1.4E-07	9.8E-07	0	0	9.3E-07	4.8E-09	3.4E-07	9.1E-07	4.3E-07	1.5E-06	0	0	0	0	1.4E-06	3.8E-06	3.8E-06	0	0	0	9.3E-10	0	0	4.2E-09	3.3E-10	1.6E-07	1.3E-10	1.3E-07	-	2.0E-05	9.0E-05
Dimethyl Sulfide	0	0	0	0	0	0	0	0	0	0	0	2.4E-07	0	0	0	0	2.8E-08	2.0E-07	0	0	0	0	1.9E-07	5.0E-07	0	0	0	0	0	0	0	2.1E-06	2.0E-06	0	0	0	2.7E-09	0	0	1.4E-08	1.2E-09	5.2E-07	3.7E-09	4.5E-08	-	5.8E-06	2.6E-05
Dimethyl Disulfide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.6E-10	0	0	8.9E-10	7.1E-11	2.9E-08	2.9E-10	2.3E-09	-	3.3E-08	1.4E-07
Carbonyl Sulfide*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4.1E-10	0	0	1.6E-09	1.3E-10	5.6E-08	2.3E-11	1.2E-07	-	1.7E-07	7.6E-07
Methanol*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.1E-05	4.9E-06	1.8E-04	2.8E-04	2.2E-05	3.5E-04	8.2E-04	4.7E-07	-	1.7E-03	0.01
2-Propanol	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.9E-10	0	0	1.2E-09	9.6E-11	3.7E-08	3.5E-11	2.9E-08	-	6.8E-08	3.0E-07
Diethanolamine*	0	0	0	0	3.3E-03	4.1E-04	0	2.4E-03	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5.5E-03	1.4E-03	0.05	3.8E-11	3.1E-12	3.7E-20	1.2E-10	8.7E-10	-	0.06	0.28
Diethylamine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	-	0.0E+00	0.0E+00
Methyl Diethanolamine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	-	0.0E+00	0.0E+00
Piperazine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	-	0.0E+00	0.0E+00
Water	0	0	3.6E-05	8.4E-05	0.01	1.2E-03	0	7.1E-03	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.02	4.2E-03	0.15	5.8E-03	4.7E-04	1.2E-03	0.02	8.7E-05	-	0.22	0.95
Total	**0.02**	**0.04**	**0.06**	**0.14**	**0.02**	**2.3E-03**	**0.06**	**0.01**	**0.03**	**0.02**	**0.04**	**0.02**	**0.02**	**0.02**	**0.01**	**2.3E-03**	**2.9E-03**	**0.02**	**0.08**	**0.03**	**0.02**	**1.2E-04**	**0.01**	**0.02**	**0.01**	**0.02**	**0.02**	**0.07**	**0.06**	**0.02**	**0.02**	**0.06**	**0.06**	**5.8E-02**	**6.9E-02**	**0.02**	**0.02**	**0.01**	**0.20**	**0.01**	**5.7E-04**	**0.03**	**0.02**	**0.02**	**0.23**	**1.71**	**7.51**
CO_2	**2.3E-05**	**5.5E-05**	**5.9E-06**	**1.4E-05**	**3.0E-05**	**3.7E-06**	**5.8E-06**	**2.0E-05**	**1.3E-05**	**1.0E-05**	**1.7E-05**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**8.1E-06**	**2.5E-04**	**1.1E-05**	**3.8E-04**	**1.0E-03**	**8.2E-05**	**0.03**	**2.4E-05**	**5.3E-07**	**0.01**	**0.04**	**0.17**
CH_4	**6.9E-05**	**1.6E-04**	**2.6E-04**	**6.1E-04**	**2.4E-05**	**3.0E-06**	**2.6E-04**	**0**	**2.2E-04**	**1.7E-04**	**2.9E-04**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**2.9E-04**	**7.5E-07**	**0**	**0**	**9.2E-07**	**7.4E-08**	**3.6E-05**	**1.1E-09**	**8.4E-04**	**0.22**	**0.22**	**0.96**
CO_2e	**0.02**	**0.05**	**0.08**	**0.19**	**0.01**	**9.3E-04**	**0.08**	**2.0E-05**	**0.07**	**0.05**	**0.09**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.09**	**4.8E-04**	**1.1E-05**	**3.8E-04**	**1.3E-03**	**1.1E-04**	**0.04**	**2.4E-05**	**0.26**	**66.81**	**67.84**	**297.15**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 114 - Y-Grade NGL to Amine Wash

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	21	0.00992	97%	0.006
	Light Liquid	70	0.0055	97%	0.012
Flanges	Gas	42	0.00086	75%	0.009
	Light Liquid	140	0.000243	75%	0.009
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	0	0.02866	93%	0.000
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	1	0.0165	0%	0.017
Total Emissions	**Gas**				**0.02**
	Light Liquid				**0.04**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0.013	2.0E-06	8.6E-06	0.01	4.7E-06	2.1E-05
Carbon Dioxide	0.152	2.3E-05	1.0E-04	0.15	5.5E-05	2.4E-04
Methane	0.449	6.9E-05	3.0E-04	0.45	1.6E-04	7.2E-04
Ethane	27.911	0.004	0.019	27.91	0.010	0.045
Propane	32.435	0.005	0.022	32.44	0.012	0.052
Propylene	0	0	0	0	0	0
Isobutane	8.117	0.001	0.005	8.12	0.003	0.013
n-Butane	14.445	0.002	0.010	14.44	0.005	0.023
Isopentane	5.154	0.001	0.003	5.15	0.002	0.008
Pentane	4.458	0.001	0.003	4.46	0.002	0.007
Cyclopentane	0.354	5.4E-05	2.4E-04	0.35	1.3E-04	5.7E-04
Hexane*	3.167	4.8E-04	0.002	3.17	0.001	0.01
Methylcyclopentane	0.870	1.3E-04	0.001	0.87	3.2E-04	1.4E-03
Benzene*	0.413	6.3E-05	2.8E-04	0.41	1.5E-04	6.6E-04
Cyclohexane	0.561	8.6E-05	3.8E-04	0.56	2.0E-04	9.0E-04
Methyl Cyclohexane	0.902	1.4E-04	0.001	0.90	3.3E-04	1.4E-03
Toluene*	0.402	6.1E-05	2.7E-04	0.40	1.5E-04	6.4E-04
Mixed Xylenes*	0.195	3.0E-05	1.3E-04	0.20	7.1E-05	3.1E-04
Mercaptans	0	0	0	0	0	0
Carbon Disulfide*	0.002	2.7E-07	1.2E-06	0.00	6.4E-07	2.8E-06
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0.015**	**0.067**	**100**	**0.037**	**0.160**
CO_2	**0.15**	**2.3E-05**	**1.0E-04**	**0.15**	**5.5E-05**	**2.4E-04**
CH_4	**0.45**	**6.9E-05**	**3.0E-04**	**0.45**	**1.6E-04**	**7.2E-04**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 114 - Regenerant

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	76	0.00992	97%	0.023
	Light Liquid	225	0.0055	97%	0.037
Flanges	Gas	154	0.00086	75%	0.033
	Light Liquid	461	0.000243	75%	0.028
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	2	0.02866	93%	0.004
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	4	0.0194	97%	0.002
	Light Liquid	4	0.0165	0%	0.066
Total Emissions	**Gas**				**0.06**
	Light Liquid				**0.14**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0.013	7.5E-06	3.3E-05	0.01	1.7E-05	7.6E-05
Carbon Dioxide	0.010	5.9E-06	2.6E-05	0.01	1.4E-05	6.0E-05
Methane	0.450	2.6E-04	1.1E-03	0.45	6.1E-04	0.003
Ethane	27.929	0.016	0.071	27.93	0.038	0.165
Propane	32.463	0.019	0.083	32.46	0.044	0.192
Propylene	0	0	0	0	0	0
Isobutane	8.124	0.005	0.021	8.12	0.011	0.048
n-Butane	14.457	0.008	0.037	14.46	0.020	0.086
Isopentane	5.159	0.003	0.013	5.16	0.007	0.031
Pentane	4.462	0.003	0.011	4.46	0.006	0.026
Cyclopentane	0.355	2.1E-04	0.001	0.35	4.8E-04	0.002
Hexane*	3.170	0.002	0.008	3.17	0.004	0.019
Methylcyclopentane	0.871	0.001	0.002	0.87	0.001	0.005
Benzene*	0.413	2.4E-04	0.001	0.41	0.001	0.002
Cyclohexane	0.561	3.3E-04	0.001	0.56	0.001	0.003
Methyl Cyclohexane	0.903	0.001	0.002	0.90	0.001	0.005
Toluene*	0.402	2.3E-04	0.001	0.40	0.001	0.002
Mixed Xylenes*	0.195	1.1E-04	5.0E-04	0.20	2.6E-04	0.001
Mercaptans	0	0	0	0	0	0
Carbon Disulfide*	0.002	1.0E-06	4.5E-06	0.00	2.4E-06	1.0E-05
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	0.062	3.6E-05	1.58E-04	0.06	8.4E-05	3.7E-04
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0.058**	**0.254**	**100**	**0.135**	**0.592**
CO_2	**0.01**	**5.9E-06**	**2.6E-05**	**0.01**	**1.4E-05**	**6.0E-05**
CH_4	**0.45**	**2.6E-04**	**0.001**	**0.45**	**6.1E-04**	**0.003**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 114/118 Mix

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	24	0.00992	97%	0.007
	Light Liquid	8	0.0055	97%	0.001
Flanges	Gas	48	0.00086	75%	0.010
	Light Liquid	16	0.000243	75%	0.001
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	0	0.02866	93%	0.000
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	2	0.0194	97%	0.001
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0.02**
	Light Liquid				**2.3E-03**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0.160	3.0E-05	1.3E-04	0.16	3.7E-06	1.6E-05
Methane	0.130	2.4E-05	1.1E-04	0.13	3.0E-06	1.3E-05
Ethane	7.880	0.001	0.006	7.88	1.8E-04	7.9E-04
Propane	9.160	0.002	0.007	9.16	2.1E-04	9.2E-04
Propylene	0	0	0	0	0	0
Isobutane	2.290	4.3E-04	0.002	2.29	5.2E-05	2.3E-04
n-Butane	4.080	0.001	0.003	4.08	9.4E-05	4.1E-04
Isopentane	1.450	2.7E-04	0.001	1.45	3.3E-05	1.5E-04
Pentane	1.260	2.3E-04	0.001	1.26	2.9E-05	1.3E-04
Cyclopentane	0.100	1.9E-05	8.2E-05	0.10	2.3E-06	1.0E-05
Hexane*	0.890	1.7E-04	0.001	0.89	2.0E-05	8.9E-05
Methylcyclopentane	0.250	4.7E-05	2.0E-04	0.25	5.7E-06	2.5E-05
Benzene*	0.120	2.2E-05	9.8E-05	0.12	2.8E-06	1.2E-05
Cyclohexane	0.160	3.0E-05	1.3E-04	0.16	3.7E-06	1.6E-05
Methyl Cyclohexane	0.250	4.7E-05	2.0E-04	0.25	5.7E-06	2.5E-05
Toluene*	0.110	2.0E-05	9.0E-05	0.11	2.5E-06	1.1E-05
Mixed Xylenes*	0.060	1.1E-05	4.9E-05	0.06	1.4E-06	6.0E-06
Mercaptans	0	0	0	0	0	0
Carbon Disulfide*	0	0	0	0	0	0
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	53.75	0.010	0.044	53.75	0.001	0.005
Diethanolamine*	17.92	0.003	0.015	17.92	0.000	0.002
Total	**100.020**	**0.019**	**0.082**	**100.02**	**0.002**	**0.010**
CO_2	**0.16**	**3.0E-05**	**1.3E-04**	**0.16**	**3.7E-06**	**1.6E-05**
CH_4	**0.13**	**2.4E-05**	**1.1E-04**	**0.13**	**3.0E-06**	**1.3E-05**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 116 - Y-Grade NGL from Dehydrators

Operating Schedule (hr/yr)	8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	0	0.00992	97%	0.000
	Light Liquid	86	0.0055	97%	0.014
Flanges	Gas	0	0.00086	75%	0.000
	Light Liquid	174	0.000243	75%	0.011
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	0	0.02866	93%	0.000
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	2	0.0165	0%	0.033
Total Emissions	**Gas**				**0**
	Light Liquid				**0.06**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0.013	0	0	0.01	7.4E-06	3.3E-05
Carbon Dioxide	0.010	0	0	0.01	5.8E-06	2.6E-05
Methane	0.453	0	0	0.45	2.6E-04	0.001
Ethane	27.945	0	0	27.94	0.016	0.071
Propane	32.485	0	0	32.48	0.019	0.082
Propylene	0	0	0	0	0	0
Isobutane	8.130	0	0	8.13	0.005	0.021
n-Butane	14.471	0	0	14.47	0.008	0.037
Isopentane	5.154	0	0	5.15	0.003	0.013
Pentane	4.474	0	0	4.47	0.003	0.011
Cyclopentane	0.354	0	0	0.35	2.0E-04	0.001
Hexane*	3.167	0	0	3.17	0.002	0.008
Methylcyclopentane	0.870	0	0	0.87	0.001	0.002
Benzene*	0.413	0	0	0.41	2.4E-04	0.001
Cyclohexane	0.561	0	0	0.56	3.2E-04	0.001
Methyl Cyclohexane	0.902	0	0	0.90	0.001	0.002
Toluene*	0.402	0	0	0.40	2.3E-04	0.001
Mixed Xylenes*	0.195	0	0	0.20	1.1E-04	4.9E-04
Mercaptans	0	0	0	0	0	0
Carbon Disulfide*	0.002	0	0	0.00	1.0E-06	4.4E-06
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0**	**0**	**100**	**0.058**	**0.253**
CO_2	**0.01**	**0**	**0**	**0.01**	**5.8E-06**	**2.6E-05**
CH_4	**0.45**	**0**	**0**	**0.45**	**2.6E-04**	**0.001**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 118 - Amine to Coalescers

Operating Schedule (hr/yr)	8760

Fugitive Emission Calculations

Emission Sources	**Phase**	**Source Count[1]**	**Uncontrolled Emission Factor[2] (lb/hr/source)**	**Control Factor[3]**	**Hourly Emission (lb/hr)**
Valves	Gas	0	0.00992	97%	0.000
	Light Liquid	33	0.0055	97%	0.005
Flanges	Gas	0	0.00086	75%	0.000
	Light Liquid	66	0.000243	75%	0.004
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	0	0.02866	93%	0.000
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0**
	Light Liquid				**0.01**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	**Gas Stream**			**Light Liquid Stream**		
	Weight Percent (%)	**Hourly Emissions (lb/hr)**	**Annual Emissions (tpy)**	**Weight Percent (%)**	**Hourly Emissions (lb/hr)**	**Annual Emissio (tpy)**
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0.213	0	0	0.213	2.0E-05	8.8E-05
Methane	0	0	0	0	0	0
Ethane	0	0	0	0	0	0
Propane	0	0	0	0	0	0
Propylene	0	0	0	0	0	0
Isobutane	0	0	0	0	0	0
n-Butane	0	0	0	0	0	0
Isopentane	0	0	0	0	0	0
Pentane	0	0	0	0	0	0
Cyclopentane	0	0	0	0	0	0
Hexane*	0	0	0	0	0	0
Methylcyclopentane	0	0	0	0	0	0
Benzene*	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0
Methyl Cyclohexane	0	0	0	0	0	0
Toluene*	0	0	0	0	0	0
Mixed Xylenes*	0	0	0	0	0	0
Mercaptans	0	0	0	0	0	0
Carbon Disulfide*	0	0	0	0	0	0
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	74.834	0	0	74.834	0.007	0.031
Diethanolamine*	24.953	0	0	24.953	0.002	0.010
Total	**100.000**	**0**	**0**	**100**	**0.009**	**0.041**
CO_2	**0.21**	**0**	**0**	**0.21**	**2.0E-05**	**8.8E-05**
CH_4	**0**	**0**	**0**	**0**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 200 - Amine to Coalescers

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	40	0.00992	97%	0.012
	Light Liquid	66	0.0055	97%	0.011
Flanges	Gas	83	0.00086	75%	0.018
	Light Liquid	134	0.000243	75%	0.008
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	2	0.02866	93%	0.004
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0.03**
	Light Liquid				**0.02**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0.028	8.3E-06	3.7E-05	0.028	6.5E-06	2.8E-05
Carbon Dioxide	0.044	1.3E-05	5.7E-05	0.044	1.0E-05	4.4E-05
Methane	0.755	2.2E-04	0.001	0.755	1.7E-04	7.6E-04
Ethane	98.466	0.029	0.128	98.466	0.023	0.099
Propane	0.707	2.1E-04	0.001	0.707	1.6E-04	0.001
Propylene	0	0	0	0	0	0
Isobutane	0	0	0	0	0	0
n-Butane	0	0	0	0	0	0
Isopentane	0	0	0	0	0	0
Pentane	0	0	0	0	0	0
Cyclopentane	0	0	0	0	0	0
Hexane*	0	0	0	0	0	0
Methylcyclopentane	0	0	0	0	0	0
Benzene*	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0
Methyl Cyclohexane	0	0	0	0	0	0
Toluene*	0	0	0	0	0	0
Mixed Xylenes*	0	0	0	0	0	0
Mercaptans	0	0	0	0	0	0
Carbon Disulfide*	0	0	0	0	0	0
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0.030**	**0.130**	**100**	**0.023**	**0.101**
CO_2	**0.04**	**1.3E-05**	**5.7E-05**	**0.04**	**1.0E-05**	**4.4E-05**
CH_4	**0.75**	**2.2E-04**	**9.8E-04**	**0.75**	**1.7E-04**	**7.6E-04**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 203 - Ethane Product to Subcooler

Operating Schedule (hr/yr)	8760

Fugitive Emission Calculations

Emission Sources	**Phase**	**Source Count[1]**	**Uncontrolled Emission Factor[2] (lb/hr/source)**	**Control Factor[3]**	**Hourly Emission (lb/hr)**
Valves	Gas	0	0.00992	97%	0.000
	Light Liquid	62	0.0055	97%	0.010
Flanges	Gas	0	0.00086	75%	0.000
	Light Liquid	124	0.000243	75%	0.008
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	2	0.02866	93%	0.004
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	1	0.0165	0%	0.017
Total Emissions	**Gas**				**0**
	Light Liquid				**0.04**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	**Gas Stream**			**Light Liquid Stream**		
	Weight Percent (%)	**Hourly Emissions (lb/hr)**	**Annual Emissions (tpy)**	**Weight Percent (%)**	**Hourly Emissions (lb/hr)**	**Annual Emissio (tpy)**
Nitrogen	0.028	0	0	0.028	1.1E-05	4.7E-05
Carbon Dioxide	0.044	0	0	0.044	1.7E-05	7.4E-05
Methane	0.755	0	0	0.755	2.9E-04	0.001
Ethane	98.466	0	0	98.466	0.038	0.165
Propane	0.707	0	0	0.707	2.7E-04	0.001
Propylene	0	0	0	0	0	0
Isobutane	0	0	0	0	0	0
n-Butane	0	0	0	0	0	0
Isopentane	0	0	0	0	0	0
Pentane	0	0	0	0	0	0
Cyclopentane	0	0	0	0	0	0
Hexane*	0	0	0	0	0	0
Methylcyclopentane	0	0	0	0	0	0
Benzene*	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0
Methyl Cyclohexane	0	0	0	0	0	0
Toluene*	0	0	0	0	0	0
Mixed Xylenes*	0	0	0	0	0	0
Mercaptans	0	0	0	0	0	0
Carbon Disulfide*	0	0	0	0	0	0
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0**	**0**	**100**	**0.038**	**0.168**
CO_2	**0.04**	**0**	**0**	**0.04**	**1.7E-05**	**7.4E-05**
CH_4	**0.75**	**0**	**0**	**0.75**	**2.9E-04**	**0.001**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 204 - Ethane Product to Subcooler

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	**Phase**	**Source Count[1]**	**Uncontrolled Emission Factor[2] (lb/hr/source)**	**Control Factor[3]**	**Hourly Emission (lb/hr)**
Valves	Gas	0	0.00992	97%	0.000
	Light Liquid	58	0.0055	97%	0.010
Flanges	Gas	0	0.00086	75%	0.000
	Light Liquid	185	0.000243	75%	0.011
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	0	0.02866	93%	0.000
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0**
	Light Liquid				**0.02**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	**Gas Stream**			**Light Liquid Stream**		
	Weight Percent (%)	**Hourly Emissions (lb/hr)**	**Annual Emissions (tpy)**	**Weight Percent (%)**	**Hourly Emissions (lb/hr)**	**Annual Emissio (tpy)**
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0
Methane	0	0	0	0	0	0
Ethane	0.158	0	0	0.158	3.3E-05	1.4E-04
Propane	45.148	0	0	45.148	0.009	0.041
Propylene	0	0	0	0	0	0
Isobutane	11.376	0	0	11.376	0.002	0.010
n-Butane	20.240	0	0	20.240	0.004	0.018
Isopentane	7.210	0	0	7.210	0.002	0.007
Pentane	6.251	0	0	6.251	0.001	0.006
Cyclopentane	0.485	0	0	0.485	1.0E-04	4.4E-04
Hexane*	4.434	0	0	4.434	0.001	0.004
Methylcyclopentane	1.228	0	0	1.228	2.6E-04	0.001
Benzene*	0.570	0	0	0.570	1.2E-04	0.001
Cyclohexane	0.772	0	0	0.772	1.6E-04	0.001
Methyl Cyclohexane	1.268	0	0	1.268	2.6E-04	0.001
Toluene*	0.569	0	0	0.569	1.2E-04	0.001
Mixed Xylenes*	0.278	0	0	0.278	5.8E-05	2.5E-04
Mercaptans	0.009	0	0	0.009	1.9E-06	8.2E-06
Carbon Disulfide*	0.003	0	0	0.003	5.9E-07	2.6E-06
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0.001	0	0	0.001	2.4E-07	1.1E-06
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0**	**0**	**100**	**0.021**	**0.091**
CO_2	**0**	**0**	**0**	**0**	**0**	**0**
CH_4	**0**	**0**	**0**	**0**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 205 - Propane to Precooler

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	0	0.00992	97%	0.000
	Light Liquid	58	0.0055	97%	0.010
Flanges	Gas	0	0.00086	75%	0.000
	Light Liquid	185	0.000243	75%	0.011
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	0	0.02866	93%	0.000
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0**
	Light Liquid				**0.02**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0
Methane	0	0	0	0	0	0
Ethane	0.355	0	0	0.355	7.4E-05	3.2E-04
Propane	99.092	0	0	99.092	0.021	0.090
Propylene	0	0	0	0	0	0
Isobutane	0.554	0	0	0.554	1.2E-04	0.001
n-Butane	0	0	0	0	0	0
Isopentane	0	0	0	0	0	0
Pentane	0	0	0	0	0	0
Cyclopentane	0	0	0	0	0	0
Hexane*	0	0	0	0	0	0
Methylcyclopentane	0	0	0	0	0	0
Benzene*	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0
Methyl Cyclohexane	0	0	0	0	0	0
Toluene*	0	0	0	0	0	0
Mixed Xylenes*	0	0	0	0	0	0
Mercaptans	0	0	0	0	0	0
Carbon Disulfide*	0	0	0	0	0	0
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0**	**0**	**100**	**0.021**	**0.091**
CO_2	**0**	**0**	**0**	**0**	**0**	**0**
CH_4	**0**	**0**	**0**	**0**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 300 - Depropanizer Overhead

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	**Phase**	**Source Count[1]**	**Uncontrolled Emission Factor[2] (lb/hr/source)**	**Control Factor[3]**	**Hourly Emission (lb/hr)**
Valves	Gas	33	0.00992	97%	0.010
	Light Liquid	24	0.0055	97%	0.004
Flanges	Gas	66	0.00086	75%	0.014
	Light Liquid	48	0.000243	75%	0.003
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	1	0.02866	93%	0.002
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	1	0.0194	97%	0.001
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0.02**
	Light Liquid				**0.01**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	**Gas Stream**			**Light Liquid Stream**		
	Weight Percent (%)	**Hourly Emissions (lb/hr)**	**Annual Emissions (tpy)**	**Weight Percent (%)**	**Hourly Emissions (lb/hr)**	**Annual Emissio (tpy)**
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0
Methane	0	0	0	0	0	0
Ethane	0.355	8.7E-05	3.8E-04	0.355	3.2E-05	1.4E-04
Propane	99.092	0.024	0.107	99.092	0.009	0.039
Propylene	0	0	0	0	0	0
Isobutane	0.554	1.4E-04	0.001	0.554	4.9E-05	2.2E-04
n-Butane	0	0	0	0	0	0
Isopentane	0	0	0	0	0	0
Pentane	0	0	0	0	0	0
Cyclopentane	0	0	0	0	0	0
Hexane*	0	0	0	0	0	0
Methylcyclopentane	0	0	0	0	0	0
Benzene*	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0
Methyl Cyclohexane	0	0	0	0	0	0
Toluene*	0	0	0	0	0	0
Mixed Xylenes*	0	0	0	0	0	0
Mercaptans	0	0	0	0	0	0
Carbon Disulfide*	0	0	0	0	0	0
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0.025**	**0.108**	**100**	**0.009**	**0.039**
CO_2	**0**	**0**	**0**	**0**	**0**	**0**
CH_4	**0**	**0**	**0**	**0**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 301 - Propane to Injection Pumps

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	0	0.00992	97%	0.000
	Light Liquid	8	0.0055	97%	0.001
Flanges	Gas	0	0.00086	75%	0.000
	Light Liquid	16	0.000243	75%	0.001
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	0	0.02866	93%	0.000
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0**
	Light Liquid				**2.3E-03**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.
[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000
[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0
Methane	0	0	0	0	0	0
Ethane	0.355	0	0	0.355	8.1E-06	3.6E-05
Propane	99.092	0	0	99.092	0.002	0.010
Propylene	0	0	0	0	0	0
Isobutane	0.554	0	0	0.554	1.3E-05	5.6E-05
n-Butane	0	0	0	0	0	0
Isopentane	0	0	0	0	0	0
Pentane	0	0	0	0	0	0
Cyclopentane	0	0	0	0	0	0
Hexane*	0	0	0	0	0	0
Methylcyclopentane	0	0	0	0	0	0
Benzene*	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0
Methyl Cyclohexane	0	0	0	0	0	0
Toluene*	0	0	0	0	0	0
Mixed Xylenes*	0	0	0	0	0	0
Mercaptans	0	0	0	0	0	0
Carbon Disulfide*	0	0	0	0	0	0
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0**	**0**	**100**	**0.002**	**0.010**
CO_2	**0**	**0**	**0**	**0**	**0**	**0**
CH_4	**0**	**0**	**0**	**0**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 302 - Debutanizer Feed

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	4	0.00992	97%	0.001
	Light Liquid	73	0.0055	97%	0.012
Flanges	Gas	8	0.00086	75%	0.002
	Light Liquid	146	0.000243	75%	0.009
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	0	0.02866	93%	0.000
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**2.9E-03**
	Light Liquid				**0.02**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0
Methane	0	0	0	0	0	0
Ethane	0	0	0	0	0	0
Propane	0.149	4.3E-06	1.9E-05	0.149	3.1E-05	1.4E-04
Propylene	0	0	0	0	0	0
Isobutane	20.407	0.001	0.003	20.407	0.004	0.019
n-Butane	37.110	0.001	0.005	37.110	0.008	0.034
Isopentane	13.216	3.8E-04	0.002	13.216	0.003	0.012
Pentane	11.462	3.3E-04	0.001	11.462	0.002	0.010
Cyclopentane	0.896	2.6E-05	1.1E-04	0.896	1.9E-04	0.001
Hexane*	8.131	0.000	0.001	8.131	0.002	0.007
Methylcyclopentane	2.254	6.6E-05	2.9E-04	2.254	4.7E-04	0.002
Benzene*	1.058	3.1E-05	1.3E-04	1.058	2.2E-04	0.001
Cyclohexane	1.425	4.1E-05	1.8E-04	1.425	3.0E-04	0.001
Methyl Cyclohexane	2.313	6.7E-05	2.9E-04	2.313	4.8E-04	0.002
Toluene*	1.035	3.0E-05	1.3E-04	1.035	2.2E-04	0.001
Mixed Xylenes*	0.523	1.5E-05	6.7E-05	0.523	1.1E-04	4.8E-04
Mercaptans	0.015	4.3E-07	1.9E-06	0.015	3.1E-06	1.4E-05
Carbon Disulfide*	0.005	1.4E-07	6.0E-07	0.005	9.8E-07	4.3E-06
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0.001	2.8E-08	1.2E-07	0.001	2.0E-07	8.8E-07
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0.003**	**0.013**	**100**	**0.021**	**0.092**
CO_2	**0**	**0**	**0**	**0**	**0**	**0**
CH_4	**0**	**0**	**0**	**0**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 304 - Depropanizer Heat Pump Outlet

Operating Schedule (hr/yr)	8760

Fugitive Emission Calculations

Emission Sources	**Phase**	**Source Count[1]**	**Uncontrolled Emission Factor[2] (lb/hr/source)**	**Control Factor[3]**	**Hourly Emission (lb/hr)**
Valves	Gas	101	0.00992	97%	0.030
	Light Liquid	100	0.0055	97%	0.017
Flanges	Gas	202	0.00086	75%	0.043
	Light Liquid	200	0.000243	75%	0.012
Pump	Gas	1	0.00529	0%	0.005
	Light Liquid	2	0.02866	93%	0.004
Compressor Seals	Gas	1	0.0194	95%	0.001
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0.08**
	Light Liquid				**0.03**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	**Gas Stream**			**Light Liquid Stream**		
	Weight Percent (%)	**Hourly Emissions (lb/hr)**	**Annual Emissions (tpy)**	**Weight Percent (%)**	**Hourly Emissions (lb/hr)**	**Annual Emissio (tpy)**
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0
Methane	0	0	0	0	0	0
Ethane	0.355	2.8E-04	0.001	0.355	1.2E-04	0.001
Propane	99.092	0.079	0.346	99.092	0.032	0.142
Propylene	0	0	0	0	0	0
Isobutane	0.554	4.4E-04	0.002	0.554	1.8E-04	0.001
n-Butane	0	0	0	0	0	0
Isopentane	0	0	0	0	0	0
Pentane	0	0	0	0	0	0
Cyclopentane	0	0	0	0	0	0
Hexane*	0	0	0	0	0	0
Methylcyclopentane	0	0	0	0	0	0
Benzene*	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0
Methyl Cyclohexane	0	0	0	0	0	0
Toluene*	0	0	0	0	0	0
Mixed Xylenes*	0	0	0	0	0	0
Mercaptans	0	0	0	0	0	0
Carbon Disulfide*	0	0	0	0	0	0
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0.080**	**0.349**	**100**	**0.033**	**0.143**
CO_2	**0**	**0**	**0**	**0**	**0**	**0**
CH_4	**0**	**0**	**0**	**0**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 400 - Debutanizer Overhead

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	**Phase**	**Source Count[1]**	**Uncontrolled Emission Factor[2] (lb/hr/source)**	**Control Factor[3]**	**Hourly Emission (lb/hr)**
Valves	Gas	31	0.00992	97%	0.009
	Light Liquid	0	0.0055	97%	0.000
Flanges	Gas	64	0.00086	75%	0.014
	Light Liquid	2	0.000243	75%	0.000
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	0	0.02866	93%	0.000
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	1	0.0194	97%	0.001
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0.02**
	Light Liquid				**1.2E-04**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	**Gas Stream**			**Light Liquid Stream**		
	Weight Percent (%)	**Hourly Emissions (lb/hr)**	**Annual Emissions (tpy)**	**Weight Percent (%)**	**Hourly Emissions (lb/hr)**	**Annual Emissio (tpy)**
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0
Methane	0	0	0	0	0	0
Ethane	0	0	0	0	0	0
Propane	0.250	5.9E-05	2.6E-04	0.250	3.0E-07	1.3E-06
Propylene	0	0	0	0	0	0
Isobutane	35.261	0.008	0.036	35.261	4.3E-05	1.9E-04
n-Butane	64.042	0.015	0.066	64.042	7.8E-05	3.4E-04
Isopentane	0.422	9.9E-05	4.4E-04	0.422	5.1E-07	2.2E-06
Pentane	0.012	2.9E-06	1.3E-05	0.012	1.5E-08	6.6E-08
Cyclopentane	0	0	0	0	0	0
Hexane*	0	0	0	0	0	0
Methylcyclopentane	0	0	0	0	0	0
Benzene*	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0
Methyl Cyclohexane	0	0	0	0	0	0
Toluene*	0	0	0	0	0	0
Mixed Xylenes*	0	0	0	0	0	0
Mercaptans	0.008	2.0E-06	8.5E-06	0.008	1.0E-08	4.4E-08
Carbon Disulfide*	0.004	9.3E-07	4.1E-06	0.004	4.8E-09	2.1E-08
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0.024**	**0.103**	**100**	**0.000**	**0.001**
CO_2	**0**	**0**	**0**	**0**	**0**	**0**
CH_4	**0**	**0**	**0**	**0**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 402 - Gasoline to Air Cooler

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	8	0.00992	97%	0.002
	Light Liquid	54	0.0055	97%	0.009
Flanges	Gas	16	0.00086	75%	0.003
	Light Liquid	108	0.000243	75%	0.007
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	0	0.02866	93%	0.000
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0.01**
	Light Liquid				**1.5E-02**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0
Methane	0	0	0	0	0	0
Ethane	0	0	0	0	0	0
Propane	0	0	0	0	0	0
Propylene	0	0	0	0	0	0
Isobutane	0	0	0	0	0	0
n-Butane	0.150	8.7E-06	3.8E-05	0.150	2.3E-05	1.0E-04
Isopentane	30.808	0.002	0.008	30.808	0.005	0.021
Pentane	27.176	0.002	0.007	27.176	0.004	0.018
Cyclopentane	2.126	1.2E-04	0.001	2.126	3.3E-04	0.001
Hexane*	19.309	0.001	0.005	19.309	0.003	0.013
Methylcyclopentane	5.334	3.1E-04	0.001	5.334	0.001	0.004
Benzene*	2.500	1.5E-04	0.001	2.500	3.9E-04	0.002
Cyclohexane	3.379	2.0E-04	0.001	3.379	0.001	0.002
Methyl Cyclohexane	5.488	3.2E-04	0.001	5.488	0.001	0.004
Toluene*	2.474	1.4E-04	0.001	2.474	3.8E-04	0.002
Mixed Xylenes*	1.233	7.2E-05	3.1E-04	1.233	1.9E-04	0.001
Mercaptans	0.012	7.2E-07	3.2E-06	0.012	1.9E-06	8.4E-06
Carbon Disulfide*	0.006	3.4E-07	1.5E-06	0.006	9.1E-07	4.0E-06
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0.003	1.9E-07	8.2E-07	0.003	5.0E-07	2.2E-06
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0.006**	**0.025**	**100**	**0.015**	**0.068**
CO_2	**0**	**0**	**0**	**0**	**0**	**0**
CH_4	**0**	**0**	**0**	**0**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 403 - N-Butane to WSAC

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	**Phase**	**Source Count[1]**	**Uncontrolled Emission Factor[2] (lb/hr/source)**	**Control Factor[3]**	**Hourly Emission (lb/hr)**
Valves	Gas	9	0.00992	97%	0.003
	Light Liquid	68	0.0055	97%	0.011
Flanges	Gas	18	0.00086	75%	0.004
	Light Liquid	136	0.000243	75%	0.008
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	2	0.02866	93%	0.004
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0.01**
	Light Liquid				**0.02**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	**Gas Stream**			**Light Liquid Stream**		
	Weight Percent (%)	**Hourly Emissions (lb/hr)**	**Annual Emissions (tpy)**	**Weight Percent (%)**	**Hourly Emissions (lb/hr)**	**Annual Emissio (tpy)**
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0
Methane	0	0	0	0	0	0
Ethane	0	0	0	0	0	0
Propane	0	0	0	0	0	0
Propylene	0	0	0	0	0	0
Isobutane	1.448	9.5E-05	4.2E-04	1.448	3.4E-04	0.001
n-Butane	97.868	0.006	0.028	97.868	0.023	0.101
Isopentane	0.645	4.2E-05	1.8E-04	0.645	1.5E-04	0.001
Pentane	0.025	1.6E-06	7.1E-06	0.025	5.8E-06	2.6E-05
Cyclopentane	0	0	0	0	0	0
Hexane*	0	0	0	0	0	0
Methylcyclopentane	0	0	0	0	0	0
Benzene*	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0
Methyl Cyclohexane	0	0	0	0	0	0
Toluene*	0	0	0	0	0	0
Mixed Xylenes*	0	0	0	0	0	0
Mercaptans	0.008	5.4E-07	2.4E-06	0.008	1.9E-06	8.5E-06
Carbon Disulfide*	0.007	4.3E-07	1.9E-06	0.007	1.5E-06	6.7E-06
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0.007**	**0.029**	**100**	**0.023**	**0.103**
CO_2	**0**	**0**	**0**	**0**	**0**	**0**
CH_4	**0**	**0**	**0**	**0**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 404 - I-Butane to WSAC

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	24	0.00992	97%	0.007
	Light Liquid	160	0.0055	97%	0.026
Flanges	Gas	48	0.00086	75%	0.010
	Light Liquid	342	0.000243	75%	0.021
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	1	0.02866	93%	0.002
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	1	0.0165	0%	0.017
Total Emissions	**Gas**				**0.02**
	Light Liquid				**0.07**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0
Methane	0	0	0	0	0	0
Ethane	0	0	0	0	0	0
Propane	0.723	1.3E-04	0.001	0.723	4.7E-04	0.002
Propylene	0	0	0	0	0	0
Isobutane	97.707	0.017	0.075	97.707	0.064	0.281
n-Butane	1.554	2.7E-04	0.001	1.554	0.001	0.004
Isopentane	0	0	0	0	0	0
Pentane	0	0	0	0	0	0
Cyclopentane	0	0	0	0	0	0
Hexane*	0	0	0	0	0	0
Methylcyclopentane	0	0	0	0	0	0
Benzene*	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0
Methyl Cyclohexane	0	0	0	0	0	0
Toluene*	0	0	0	0	0	0
Mixed Xylenes*	0	0	0	0	0	0
Mercaptans	0.017	2.9E-06	1.3E-05	0.017	1.1E-05	4.8E-05
Carbon Disulfide*	0	0	0	0	0	0
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0.017**	**0.076**	**100**	**0.066**	**0.288**
CO_2	**0**	**0**	**0**	**0**	**0**	**0**
CH_4	**0**	**0**	**0**	**0**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 500 - Deisobutanizer Overhead

Operating Schedule (hr/yr)	8760

Fugitive Emission Calculations

Emission Sources	**Phase**	**Source Count[1]**	**Uncontrolled Emission Factor[2] (lb/hr/source)**	**Control Factor[3]**	**Hourly Emission (lb/hr)**
Valves	Gas	71	0.00992	97%	0.021
	Light Liquid	0	0.0055	97%	0.000
Flanges	Gas	147	0.00086	75%	0.032
	Light Liquid	0	0.000243	75%	0.000
Pump	Gas	1	0.00529	0%	0.005
	Light Liquid	0	0.02866	93%	0.000
Compressor Seals	Gas	1	0.0194	95%	0.001
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	1	0.0194	97%	0.001
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0.06**
	Light Liquid				**0**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	**Gas Stream**			**Light Liquid Stream**		
	Weight Percent (%)	**Hourly Emissions (lb/hr)**	**Annual Emissions (tpy)**	**Weight Percent (%)**	**Hourly Emissions (lb/hr)**	**Annual Emissio (tpy)**
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0
Methane	0	0	0	0	0	0
Ethane	0	0	0	0	0	0
Propane	0.723	4.3E-04	0.002	0.723	0	0
Propylene	0	0	0	0	0	0
Isobutane	97.707	0.058	0.255	97.707	0	0
n-Butane	1.554	0.001	0.004	1.554	0	0
Isopentane	0	0	0	0	0	0
Pentane	0	0	0	0	0	0
Cyclopentane	0	0	0	0	0	0
Hexane*	0	0	0	0	0	0
Methylcyclopentane	0	0	0	0	0	0
Benzene*	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0
Methyl Cyclohexane	0	0	0	0	0	0
Toluene*	0	0	0	0	0	0
Mixed Xylenes*	0	0	0	0	0	0
Mercaptans	0.017	9.9E-06	4.3E-05	0.017	0	0
Carbon Disulfide*	0	0	0	0	0	0
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0.060**	**0.261**	**100**	**0**	**0**
CO_2	**0**	**0**	**0**	**0**	**0**	**0**
CH_4	**0**	**0**	**0**	**0**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 501 - I-Butane to Injection Pump

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	0	0.00992	97%	0.000
	Light Liquid	55	0.0055	97%	0.009
Flanges	Gas	0	0.00086	75%	0.000
	Light Liquid	110	0.000243	75%	0.007
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	2	0.02866	93%	0.004
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0**
	Light Liquid				**0.02**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0
Methane	0	0	0	0	0	0
Ethane	0	0	0	0	0	0
Propane	0.723	0	0	0.723	1.4E-04	0.001
Propylene	0	0	0	0	0	0
Isobutane	97.707	0	0	97.707	0.019	0.085
n-Butane	1.554	0	0	1.554	3.1E-04	0.001
Isopentane	0	0	0	0	0	0
Pentane	0	0	0	0	0	0
Cyclopentane	0	0	0	0	0	0
Hexane*	0	0	0	0	0	0
Methylcyclopentane	0	0	0	0	0	0
Benzene*	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0
Methyl Cyclohexane	0	0	0	0	0	0
Toluene*	0	0	0	0	0	0
Mixed Xylenes*	0	0	0	0	0	0
Mercaptans	0.017	0	0	0.017	3.3E-06	1.4E-05
Carbon Disulfide*	0	0	0	0	0	0
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0**	**0**	**100**	**0.020**	**0.087**
CO_2	**0**	**0**	**0**	**0**	**0**	**0**
CH_4	**0**	**0**	**0**	**0**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 502 - N-Butane to Injection Pump

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	0	0.00992	97%	0.000
	Light Liquid	62	0.0055	97%	0.010
Flanges	Gas	0	0.00086	75%	0.000
	Light Liquid	124	0.000243	75%	0.008
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	2	0.02866	93%	0.004
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0**
	Light Liquid				**0.02**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0
Methane	0	0	0	0	0	0
Ethane	0	0	0	0	0	0
Propane	0	0	0	0	0	0
Propylene	0	0	0	0	0	0
Isobutane	1.448	0	0	1.448	3.2E-04	0.001
n-Butane	97.868	0	0	97.868	0.021	0.093
Isopentane	0.645	0	0	0.645	1.4E-04	6.1E-04
Pentane	0.025	0	0	0.025	5.4E-06	2.4E-05
Cyclopentane	0	0	0	0	0	0
Hexane*	0	0	0	0	0	0
Methylcyclopentane	0	0	0	0	0	0
Benzene*	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0
Methyl Cyclohexane	0	0	0	0	0	0
Toluene*	0	0	0	0	0	0
Mixed Xylenes*	0	0	0	0	0	0
Mercaptans	0.008	0	0	0.008	1.8E-06	7.9E-06
Carbon Disulfide*	0.007	0	0	0.007	1.4E-06	6.2E-06
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0**	**0**	**100**	**0.022**	**0.095**
CO_2	**0**	**0**	**0**	**0**	**0**	**0**
CH_4	**0**	**0**	**0**	**0**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 504 - Gasoline to Treating

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	79	0.00992	97%	0.024
	Light Liquid	201	0.0055	97%	0.033
Flanges	Gas	158	0.00086	75%	0.034
	Light Liquid	402	0.000243	75%	0.024
Pump	Gas	1	0.00529	0%	0.005
	Light Liquid	3	0.02866	93%	0.006
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	3	0.0194	97%	0.002
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0.06**
	Light Liquid				**0.06**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0
Methane	0	0	0	0	0	0
Ethane	0	0	0	0	0	0
Propane	0	0	0	0	0	0
Propylene	0	0	0	0	0	0
Isobutane	0	0	0	0	0	0
n-Butane	0.150	9.7E-05	4.2E-04	0.150	9.5E-05	4.2E-04
Isopentane	30.808	0.020	0.087	30.808	0.020	0.086
Pentane	27.176	0.018	0.077	27.176	0.017	0.076
Cyclopentane	2.126	0.001	0.006	2.126	0.001	0.006
Hexane*	19.309	0.012	0.055	19.309	0.012	0.054
Methylcyclopentane	5.334	0.003	0.015	5.334	0.003	0.015
Benzene*	2.500	0.002	0.007	2.500	0.002	0.007
Cyclohexane	3.379	0.002	0.010	3.379	0.002	0.009
Methyl Cyclohexane	5.488	0.004	0.016	5.488	0.003	0.015
Toluene*	2.474	0.002	0.007	2.474	0.002	0.007
Mixed Xylenes*	1.233	0.001	0.003	1.233	0.001	0.003
Mercaptans	0.012	8.0E-06	3.5E-05	0.012	7.9E-06	3.5E-05
Carbon Disulfide*	0.006	3.8E-06	1.7E-05	0.006	3.8E-06	1.6E-05
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0.003	2.1E-06	9.1E-06	0.003	2.0E-06	8.9E-06
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0.065**	**0.283**	**100**	**0.064**	**0.279**
CO_2	**0**	**0**	**0**	**0**	**0**	**0**
CH_4	**0**	**0**	**0**	**0**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 700 - Refrigerant Compressor Inlet

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	77	0.00992	97%	0.023
	Light Liquid	177	0.0055	97%	0.029
Flanges	Gas	154	0.00086	75%	0.033
	Light Liquid	354	0.000243	75%	0.022
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	1	0.02866	93%	0.002
Compressor Seals	Gas	1	0.0194	95%	0.001
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	2	0.0194	97%	0.001
	Light Liquid	1	0.0165	0%	0.017
Total Emissions	**Gas**				**0.06**
	Light Liquid				**0.07**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0
Methane	0	0	0	0	0	0
Ethane	0.086	5.0E-05	2.2E-04	0.086	5.9E-05	2.6E-04
Propane	1.391	0.001	0.004	1.391	0.001	0.004
Propylene	97.971	0.057	0.250	97.971	0.068	0.30
Isobutane	0.552	3.2E-04	0.001	0.552	3.8E-04	0.002
n-Butane	0	0	0	0	0	0
Isopentane	0	0	0	0	0	0
Pentane	0	0	0	0	0	0
Cyclopentane	0	0	0	0	0	0
Hexane*	0	0	0	0	0	0
Methylcyclopentane	0	0	0	0	0	0
Benzene*	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0
Methyl Cyclohexane	0	0	0	0	0	0
Toluene*	0	0	0	0	0	0
Mixed Xylenes*	0	0	0	0	0	0
Mercaptans	0	0	0	0	0	0
Carbon Disulfide*	0	0	0	0	0	0
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0.058**	**0.255**	**100**	**0.069**	**0.303**
CO_2	**0**	**0**	**0**	**0**	**0**	**0**
CH_4	**0**	**0**	**0**	**0**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 701 - Ethane to Injection Pump

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	**Phase**	**Source Count[1]**	**Uncontrolled Emission Factor[2] (lb/hr/source)**	**Control Factor[3]**	**Hourly Emission (lb/hr)**
Valves	Gas	0	0.00992	97%	0.000
	Light Liquid	50	0.0055	97%	0.008
Flanges	Gas	0	0.00086	75%	0.000
	Light Liquid	100	0.000243	75%	0.006
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	2	0.02866	93%	0.004
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0**
	Light Liquid				**0.02**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	**Gas Stream**			**Light Liquid Stream**		
	Weight Percent (%)	**Hourly Emissions (lb/hr)**	**Annual Emissions (tpy)**	**Weight Percent (%)**	**Hourly Emissions (lb/hr)**	**Annual Emissio (tpy)**
Nitrogen	0.057	0	0	0.057	1.0E-05	4.5E-05
Carbon Dioxide	0.044	0	0	0.044	8.1E-06	3.6E-05
Methane	1.585	0	0	1.585	2.9E-04	1.3E-03
Ethane	97.602	0	0	97.602	0.018	0.08
Propane	0.712	0	0	0.712	1.3E-04	5.7E-04
Propylene	0	0	0	0	0	0
Isobutane	0	0	0	0	0	0
n-Butane	0	0	0	0	0	0
Isopentane	0	0	0	0	0	0
Pentane	0	0	0	0	0	0
Cyclopentane	0	0	0	0	0	0
Hexane*	0	0	0	0	0	0
Methylcyclopentane	0	0	0	0	0	0
Benzene*	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0
Methyl Cyclohexane	0	0	0	0	0	0
Toluene*	0	0	0	0	0	0
Mixed Xylenes*	0	0	0	0	0	0
Mercaptans	0	0	0	0	0	0
Carbon Disulfide*	0	0	0	0	0	0
Carbonyl Sulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Water	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Total	**100.000**	**0**	**0**	**100**	**0.018**	**0.080**
CO_2	**0.04**	**0**	**0**	**0.04**	**8.1E-06**	**3.6E-05**
CH_4	**1.6E+00**	**0**	**0**	**1.6E+00**	**2.9E-04**	**1.3E-03**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 05032 - Rich Amine to Regeneration

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	0	0.00992	97%	0.000
	Light Liquid	77	0.0055	97%	0.013
Flanges	Gas	0	0.00086	75%	0.000
	Light Liquid	154	0.000243	75%	0.009
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	0	0.02866	93%	0.000
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0**
	Light Liquid				**0.02**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emission (tpy)
Nitrogen	1.2E-04	0	0	1.2E-04	2.6E-08	1.1E-07
Carbon Dioxide	1.129	0	0	1.129	2.5E-04	1.1E-03
Methane	0.003	0	0	0.003	7.5E-07	3.3E-06
Ethane	0.071	0	0	0.071	1.6E-05	6.8E-05
Propane	0.021	0	0	0.021	4.6E-06	2.0E-05
Isobutane	0.001	0	0	0.001	3.3E-07	1.4E-06
n-Butane	0.003	0	0	0.003	6.2E-07	2.7E-06
Isopentane	2.9E-04	0	0	2.9E-04	6.3E-08	2.8E-07
Pentane	2.4E-04	0	0	2.4E-04	5.3E-08	2.3E-07
Cyclopentane	7.6E-05	0	0	7.6E-05	1.7E-08	7.4E-08
Hexane*	3.9E-05	0	0	3.9E-05	8.6E-09	3.8E-08
Methylcyclopentane	5.3E-05	0	0	5.3E-05	1.2E-08	5.2E-08
Cyclohexane	4.7E-05	0	0	4.7E-05	1.0E-08	4.5E-08
Methyl Cyclohexane	1.8E-05	0	0	1.8E-05	4.0E-09	1.7E-08
Benzene*	1.6E-03	0	0	1.6E-03	3.5E-07	1.5E-06
Toluene*	5.5E-04	0	0	5.5E-04	1.2E-07	5.4E-07
Ethylbenzene*	0	0	0	0	0	0
o-Xylene*	4.1E-05	0	0	4.1E-05	9.2E-09	4.0E-08
p-Xylene*	4.5E-05	0	0	4.5E-05	9.9E-09	4.3E-08
m-Xylene*	3.3E-05	0	0	3.3E-05	7.3E-09	3.2E-08
Hydrogen Sulfide	0	0	0	0	0	0
Methyl Mercaptan	1.8E-04	0	0	1.8E-04	4.0E-08	1.8E-07
Ethyl Mercaptan	5.8E-05	0	0	5.8E-05	1.3E-08	5.6E-08
n-Propyl Mercaptan	1.2E-05	0	0	1.2E-05	2.6E-09	1.1E-08
n-Butyl Mercaptan	1.1E-06	0	0	1.1E-06	2.5E-10	1.1E-09
Carbon Disulfide*	4.2E-06	0	0	4.2E-06	9.3E-10	4.1E-09
Dimethyl Sulfide	1.2E-05	0	0	1.2E-05	2.7E-09	1.2E-08
Dimethyl Disulfide	7.4E-07	0	0	7.4E-07	1.6E-10	7.2E-10
Carbonyl Sulfide*	1.9E-06	0	0	1.9E-06	4.1E-10	1.8E-09
Methanol*	0.094	0	0	0.094	2.1E-05	9.1E-05
2-Propanol	1.3E-06	0	0	1.3E-06	2.9E-10	1.3E-09
Diethanolamine*	24.766	0	0	24.766	0.01	0.02
Diethylamine	0	0	0	0	0	0
Methyl Diethanolamine	0	0	0	0	0	0
Piperazine	0	0	0	0	0	0
Water	73.909	0	0	73.909	0.02	0.07
Total	**100**	**0**	**0**	**100**	**0.022**	**0.097**
CO_2	**1.13**	**0**	**0**	**1.13**	**2.5E-04**	**0.001**
CH_4	**3.4E-03**	**0**	**0**	**3.4E-03**	**7.5E-07**	**3.3E-06**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 55015 - Lean Amine to Lean/Rich Heat Exchanger

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	7	0.00992	97%	0.002
	Light Liquid	227	0.0055	97%	0.037
Flanges	Gas	14	0.00086	75%	0.003
	Light Liquid	454	0.000243	75%	0.028
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	3	0.02866	93%	0.006
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	1	0.0194	97%	0.001
	Light Liquid	8	0.0165	0%	0.132
Total Emissions	**Gas**				**0.01**
	Light Liquid				**0.20**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0.189	1.1E-05	4.7E-05	0.189	3.8E-04	1.7E-03
Methane	0	0	0	0	0	0
Ethane	0	0	0	0	0	0
Propane	0	0	0	0	0	0
Isobutane	0	0	0	0	0	0
n-Butane	0	0	0	0	0	0
Isopentane	0	0	0	0	0	0
Pentane	0	0	0	0	0	0
Cyclopentane	0	0	0	0	0	0
Hexane*	0	0	0	0	0	0
Methylcyclopentane	0	0	0	0	0	0
Cyclohexane	0	0	0	0	0	0
Methyl Cyclohexane	0	0	0	0	0	0
Benzene*	0	0	0	0	0	0
Toluene*	0	0	0	0	0	0
Ethylbenzene*	0	0	0	0	0	0
o-Xylene*	0	0	0	0	0	0
p-Xylene*	0	0	0	0	0	0
m-Xylene*	0	0	0	0	0	0
Hydrogen Sulfide	0	0	0	0	0	0
Methyl Mercaptan	0	0	0	0	0	0
Ethyl Mercaptan	0	0	0	0	0	0
n-Propyl Mercaptan	0	0	0	0	0	0
n-Butyl Mercaptan	0	0	0	0	0	0
Carbon Disulfide*	0	0	0	0	0	0
Dimethyl Sulfide	0	0	0	0	0	0
Dimethyl Disulfide	0	0	0	0	0	0
Carbonyl Sulfide*	0	0	0	0	0	0
Methanol*	0.087	4.9E-06	2.2E-05	0.087	1.8E-04	7.7E-04
2-Propanol	0	0	0	0	0	0
Diethanolamine*	25.037	0.001	0.006	25.037	0.051	0.22
Diethylamine	0	0	0	0	0	0
Methyl Diethanolamine	0	0	0	0	0	0
Piperazine	0	0	0	0	0	0
Water	74.687	0.004	0.019	74.687	0.152	0.66
Total	**100**	**0.006**	**0.025**	**100**	**0.203**	**0.889**
CO_2	**0.19**	**1.1E-05**	**4.7E-05**	**0.19**	**3.8E-04**	**0.002**
CH_4	**0**	**0**	**0**	**0**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 55030 - Amine Regenerator Column Overheads

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	9	0.00992	97%	0.003
	Light Liquid	2	0.0055	97%	0.000
Flanges	Gas	18	0.00086	75%	0.004
	Light Liquid	4	0.000243	75%	0.000
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	0	0.02866	93%	0.000
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	1	0.0194	97%	0.001
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0.01**
	Light Liquid				**5.7E-04**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	2.1E-04	1.5E-08	6.7E-08	2.1E-04	1.2E-09	5.4E-09
Carbon Dioxide	14.348	0.001	0.004	14.348	8.2E-05	3.6E-04
Methane	0.013	9.2E-07	4.0E-06	0.013	7.4E-08	3.3E-07
Ethane	0.358	2.6E-05	1.1E-04	0.358	2.1E-06	9.0E-06
Propane	0.090	6.4E-06	2.8E-05	0.090	5.1E-07	2.3E-06
Isobutane	0.005	3.4E-07	1.5E-06	0.005	2.7E-08	1.2E-07
n-Butane	0.012	8.4E-07	3.7E-06	0.012	6.7E-08	2.9E-07
Isopentane	0.001	6.1E-08	2.7E-07	0.001	4.9E-09	2.2E-08
Pentane	0.001	5.9E-08	2.6E-07	0.001	4.7E-09	2.1E-08
Cyclopentane	0.001	5.1E-08	2.2E-07	0.001	4.1E-09	1.8E-08
Hexane*	1.1E-04	8.0E-09	3.5E-08	1.1E-04	6.4E-10	2.8E-09
Methylcyclopentane	4.0E-04	2.9E-08	1.3E-07	4.0E-04	2.3E-09	1.0E-08
Cyclohexane	4.2E-04	3.0E-08	1.3E-07	4.2E-04	2.4E-09	1.1E-08
Methyl Cyclohexane	1.2E-04	8.7E-09	3.8E-08	1.2E-04	7.0E-10	3.1E-09
Benzene*	0.024	1.7E-06	7.5E-06	0.024	1.4E-07	6.0E-07
Toluene*	0.008	6.0E-07	2.6E-06	0.008	4.8E-08	2.1E-07
Ethylbenzene*	0	0	0	0	0	0
o-Xylene*	0.001	4.5E-08	2.0E-07	0.001	3.6E-09	1.6E-08
p-Xylene*	0.001	4.9E-08	2.1E-07	0.001	3.9E-09	1.7E-08
m-Xylene*	0.001	3.6E-08	1.6E-07	0.001	2.9E-09	1.3E-08
Hydrogen Sulfide	0	0	0	0	0	0
Methyl Mercaptan	0.003	2.1E-07	9.0E-07	0.003	1.7E-08	7.2E-08
Ethyl Mercaptan	0.001	6.4E-08	2.8E-07	0.001	5.2E-09	2.3E-08
n-Propyl Mercaptan	1.8E-04	1.3E-08	5.7E-08	1.8E-04	1.0E-09	4.6E-09
n-Butyl Mercaptan	1.7E-05	1.2E-09	5.2E-09	1.7E-05	9.5E-11	4.2E-10
Carbon Disulfide*	5.8E-05	4.2E-09	1.8E-08	5.8E-05	3.3E-10	1.5E-09
Dimethyl Sulfide	2.0E-04	1.4E-08	6.3E-08	2.0E-04	1.2E-09	5.1E-09
Dimethyl Disulfide	1.2E-05	8.9E-10	3.9E-09	1.2E-05	7.1E-11	3.1E-10
Carbonyl Sulfide*	2.3E-05	1.6E-09	7.0E-09	2.3E-05	1.3E-10	5.7E-10
Methanol*	3.858	2.8E-04	0.001	3.858	2.2E-05	9.7E-05
2-Propanol	1.7E-05	1.2E-09	5.2E-09	1.7E-05	9.6E-11	4.2E-10
Diethanolamine*	5.3E-07	3.8E-11	1.7E-10	5.3E-07	3.1E-12	1.3E-11
Diethylamine	0	0	0	0	0	0
Methyl Diethanolamine	0	0	0	0	0	0
Piperazine	0	0	0	0	0	0
Water	81.275	0.006	0.025	81.275	4.7E-04	2.0E-03
Total	**100**	**0.007**	**0.031**	**100**	**0.001**	**0.003**
CO_2	**14.35**	**0.001**	**0.004**	**14.35**	**8.2E-05**	**3.6E-04**
CH_4	**1.3E-02**	**9.2E-07**	**4.0E-06**	**1.3E-02**	**7.4E-08**	**3.3E-07**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 55032a - Acid Gas to Thermal Oxidizer

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	43	0.00992	97%	0.013
	Light Liquid	0	0.0055	97%	0.000
Flanges	Gas	86	0.00086	75%	0.018
	Light Liquid	0	0.000243	75%	0.000
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	0	0.02866	93%	0.000
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	1	0.0194	97%	0.001
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0.03**
	Light Liquid				**0**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	90.550	0.029	0.126	90.550	0	0
Methane	0.112	3.6E-05	1.6E-04	0.112	0	0
Ethane	3.105	0.001	0.004	3.105	0	0
Propane	0.778	2.5E-04	0.001	0.778	0	0
Isobutane	0.042	1.3E-05	5.8E-05	0.042	0	0
n-Butane	0.102	3.2E-05	1.4E-04	0.102	0	0
Isopentane	0.007	2.4E-06	1.0E-05	0.007	0	0
Pentane	0.007	2.3E-06	9.9E-06	0.007	0	0
Cyclopentane	0.006	2.0E-06	8.6E-06	0.006	0	0
Hexane*	0.001	3.2E-07	1.4E-06	0.001	0	0
Methylcyclopentane	0.004	1.1E-06	4.9E-06	0.004	0	0
Cyclohexane	0.004	1.2E-06	5.1E-06	0.004	0	0
Methyl Cyclohexane	0.001	3.3E-07	1.5E-06	0.001	0	0
Benzene*	0.202	6.4E-05	2.8E-04	0.202	0	0
Toluene*	0.071	2.3E-05	1.0E-04	0.071	0	0
Ethylbenzene*	0	0	0	0	0	0
o-Xylene*	0.005	1.7E-06	7.5E-06	0.005	0	0
p-Xylene*	0.006	1.8E-06	8.0E-06	0.006	0	0
m-Xylene*	0.004	1.4E-06	6.0E-06	0.004	0	0
Hydrogen Sulfide	0	0	0	0	0	0
Methyl Mercaptan	0.024	7.5E-06	3.3E-05	0.024	0	0
Ethyl Mercaptan	0.007	2.4E-06	1.0E-05	0.007	0	0
n-Propyl Mercaptan	0.001	4.7E-07	2.1E-06	0.001	0	0
n-Butyl Mercaptan	0.000	0.000	0.000	0.000	0	0
Carbon Disulfide*	0.001	1.6E-07	7.2E-07	0.001	0	0
Dimethyl Sulfide	0.002	5.2E-07	2.3E-06	0.002	0	0
Dimethyl Disulfide	0	0	0	0	0	0
Carbonyl Sulfide*	0	0	0	0	0	0
Methanol*	1.112	3.5E-04	0.002	1.112	0	0
2-Propanol	0	0	0	0	0	0
Diethanolamine*	0	0	0	0	0	0
Diethylamine	0	0	0	0	0	0
Methyl Diethanolamine	0	0	0	0	0	0
Piperazine	0	0	0	0	0	0
Water	3.845	0.001	0.005	3.845	0	0
Total	**100**	**0.032**	**0.140**	**100**	**0**	**0**
CO_2	**90.55**	**0.029**	**0.126**	**90.55**	**0**	**0**
CH_4	**0.112**	**3.6E-05**	**1.6E-04**	**0.112**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 55038 - Condensate from Amine Regenerator Overhead Condenser

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	0	0.00992	97%	0.000
	Light Liquid	51	0.0055	97%	0.008
Flanges	Gas	0	0.00086	75%	0.000
	Light Liquid	102	0.000243	75%	0.006
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	2	0.02866	93%	0.004
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	0	0.0194	97%	0.000
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0**
	Light Liquid				**0.02**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	5.0E-08	0	0	5.0E-08	9.4E-12	4.1E-11
Carbon Dioxide	0.128	0	0	0.128	2.4E-05	1.0E-04
Methane	5.9E-06	0	0	5.9E-06	1.1E-09	4.8E-09
Ethane	1.8E-04	0	0	1.8E-04	3.4E-08	1.5E-07
Propane	3.5E-05	0	0	3.5E-05	6.5E-09	2.9E-08
Isobutane	1.2E-06	0	0	1.2E-06	2.2E-10	9.6E-10
n-Butane	4.3E-06	0	0	4.3E-06	8.1E-10	3.5E-09
Isopentane	1.6E-07	0	0	1.6E-07	3.0E-11	1.3E-10
Pentane	1.9E-07	0	0	1.9E-07	3.5E-11	1.6E-10
Cyclopentane	8.5E-07	0	0	8.5E-07	1.6E-10	7.0E-10
Hexane*	1.5E-08	0	0	1.5E-08	2.7E-12	1.2E-11
Methylcyclopentane	2.5E-07	0	0	2.5E-07	4.7E-11	2.1E-10
Cyclohexane	4.4E-07	0	0	4.4E-07	8.2E-11	3.6E-10
Methyl Cyclohexane	6.3E-08	0	0	6.3E-08	1.2E-11	5.1E-11
Benzene*	0.001	0	0	0.001	1.5E-07	6.6E-07
Toluene*	2.2E-04	0	0	2.2E-04	4.0E-08	1.8E-07
Ethylbenzene*	0	0	0	0	0	0
o-Xylene*	2.0E-05	0	0	2.0E-05	3.7E-09	1.6E-08
p-Xylene*	2.1E-05	0	0	2.1E-05	4.0E-09	1.8E-08
m-Xylene*	1.6E-05	0	0	1.6E-05	2.9E-09	1.3E-08
Hydrogen Sulfide	0	0	0	0	0	0
Methyl Mercaptan	1.8E-04	0	0	1.8E-04	3.4E-08	1.5E-07
Ethyl Mercaptan	4.9E-05	0	0	4.9E-05	9.1E-09	4.0E-08
n-Propyl Mercaptan	8.2E-06	0	0	8.2E-06	1.5E-09	6.7E-09
n-Butyl Mercaptan	3.5E-07	0	0	3.5E-07	6.6E-11	2.9E-10
Carbon Disulfide*	6.9E-07	0	0	6.9E-07	1.3E-10	5.6E-10
Dimethyl Sulfide	2.0E-05	0	0	2.0E-05	3.7E-09	1.6E-08
Dimethyl Disulfide	1.6E-06	0	0	1.6E-06	2.9E-10	1.3E-09
Carbonyl Sulfide*	1.2E-07	0	0	1.2E-07	2.3E-11	1.0E-10
Methanol*	4.405	0	0	4.405	0.001	3.6E-03
2-Propanol	1.9E-07	0	0	1.9E-07	3.5E-11	1.5E-10
Diethanolamine*	6.3E-07	0	0	6.3E-07	1.2E-10	5.1E-10
Diethylamine	0	0	0	0	0	0
Methyl Diethanolamine	0	0	0	0	0	0
Piperazine	0	0	0	0	0	0
Water	95.466	0	0	95.466	0.018	0.08
Total	**100**	**0**	**0**	**100**	**0.019**	**0.082**
CO_2	**0.13**	**0**	**0**	**0.13**	**2.4E-05**	**1.0E-04**
CH_4	**5.9E-06**	**0**	**0**	**5.9E-06**	**1.1E-09**	**4.8E-09**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Stream 55062 - Rich Amine Flash Tank Vent to Thermal Oxidizer

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	30	0.00992	97%	0.009
	Light Liquid	0	0.0055	97%	0.000
Flanges	Gas	60	0.00086	75%	0.013
	Light Liquid	0	0.000243	75%	0.000
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	0	0.02866	93%	0.000
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	1	0.0194	97%	0.001
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0.02**
	Light Liquid				**0**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0	0	0	0	0	0
Carbon Dioxide	0.002	5.3E-07	2.3E-06	0.002	0	0
Methane	3.748	0.001	0.004	3.748	0	0
Ethane	68.568	0.015	0.067	68.568	0	0
Propane	21.739	0.005	0.021	21.739	0	0
Isobutane	1.728	3.9E-04	0.002	1.728	0	0
n-Butane	2.982	0.001	0.003	2.982	0	0
Isopentane	0.337	7.6E-05	3.3E-04	0.337	0	0
Pentane	0.271	6.1E-05	2.7E-04	0.271	0	0
Cyclopentane	0.042	9.5E-06	4.2E-05	0.042	0	0
Hexane*	0.047	1.0E-05	4.6E-05	0.047	0	0
Methylcyclopentane	0.039	8.8E-06	3.8E-05	0.039	0	0
Cyclohexane	0.028	6.3E-06	2.8E-05	0.028	0	0
Methyl Cyclohexane	0.015	3.3E-06	1.5E-05	0.015	0	0
Benzene*	0.046	1.0E-05	4.5E-05	0.046	0	0
Toluene*	0.008	1.8E-06	7.8E-06	0.008	0	0
Ethylbenzene*	0	0	0	0	0	0
o-Xylene*	4.6E-04	1.0E-07	4.5E-07	4.6E-04	0	0
p-Xylene*	4.6E-04	1.0E-07	4.5E-07	4.6E-04	0	0
m-Xylene*	3.4E-04	7.7E-08	3.4E-07	3.4E-04	0	0
Hydrogen Sulfide	0	0	0	0	0	0
Methyl Mercaptan	0.004	8.2E-07	3.6E-06	0.004	0	0
Ethyl Mercaptan	0.001	3.0E-07	1.3E-06	0.001	0	0
n-Propyl Mercaptan	4.1E-04	9.2E-08	4.0E-07	4.1E-04	0	0
n-Butyl Mercaptan	9.8E-05	2.2E-08	9.6E-08	9.8E-05	0	0
Carbon Disulfide*	0.001	1.3E-07	5.7E-07	0.001	0	0
Dimethyl Sulfide	2.0E-04	4.5E-08	2.0E-07	2.0E-04	0	0
Dimethyl Disulfide	1.0E-05	2.3E-09	1.0E-08	1.0E-05	0	0
Carbonyl Sulfide*	0.001	1.2E-07	5.1E-07	0.001	0	0
Methanol*	0.002	4.7E-07	2.0E-06	0.002	0	0
2-Propanol	1.3E-04	2.9E-08	1.3E-07	1.3E-04	0	0
Diethanolamine*	3.9E-06	8.7E-10	3.8E-09	3.9E-06	0	0
Diethylamine	0	0	0	0	0	0
Methyl Diethanolamine	0	0	0	0	0	0
Piperazine	0	0	0	0	0	0
Water	0.390	8.7E-05	3.8E-04	0.390	0	0
Total	**100**	**0.022**	**0.098**	**100**	**0**	**0**
CO_2	**2.4E-03**	**5.3E-07**	**2.3E-06**	**2.4E-03**	**0**	**0**
CH_4	**3.748**	**8.4E-04**	**3.7E-03**	**3.748**	**0**	**0**

Jefferson County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1 & FUG2 (Emissions represent one train, but are the same for both trains.)
Natural Gas Fuel System

Operating Schedule (hr/yr) 8760

Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	317	0.00992	97%	0.094
	Light Liquid	0	0.0055	97%	0.000
Flanges	Gas	634	0.00086	75%	0.136
	Light Liquid	0	0.000243	75%	0.000
Pump	Gas	0	0.00529	0%	0.000
	Light Liquid	0	0.02866	93%	0.000
Compressor Seals	Gas	0	0.0194	95%	0.000
	Light Liquid	0	0.0165	95%	0.000
Relief Valves	Gas	1	0.0194	97%	0.001
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0.23**
	Light Liquid				**0**

[1] Estimated from P&IDs for a single train. Must be multiplied by 2 for two trains.

[2] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3] TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000. Based on 28LAER, aligned with NSPS OOOO.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Nitrogen	0.487	0.001	0.005	0.487	0	0
Carbon Dioxide	3.564	0.008	0.036	3.564	0	0
Methane	93.186	0.215	0.944	93.186	0	0
Ethane	2.508	0.006	0.025	2.508	0	0
Propane	0.185	4.3E-04	0.002	0.185	0	0
Isobutane	0.035	8.1E-05	3.5E-04	0.035	0	0
n-Butane	0.035	8.1E-05	3.5E-04	0.035	0	0
Total	**100.000**	**0.231**	**1.013**	**100.000**	**0**	**0**
CO_2	**3.56**	**0.008**	**0.036**	**3.56**	**0**	**0**
CH_4	**93.19**	**0.215**	**0.944**	**93**	**0**	**0**

ATTACHMENT C

SUPPORTING DOCUMENTATION

Diethanol Amine MSDS

Chemtherm 550 Hot Oil MSDS

Inlet Feed Composition

Diethanol Amine MSDS

MATERIAL SAFETY DATA SHEET

DIETHANOLAMINE

SECTION 1: IDENTIFICATION

Product Name:	Diethanolamine (All Grades)
Chemical Name:	2,2'iminobisetanol
CAS Number:	111-42-2
Synonyms:	All Grades includes: DEA, DEA-LFG
Chemical Family:	Ethanolamines

Telephone Numbers:
Emergency: CHEMTREC 800-424-9300

SECTION 2: COMPOSITION

Component Name:	Diethanolamine	Water
CAS #:	111-42-2	7732-18-5
OSHA PEL:	N/L	N/L
OSHA STEL:	N/L	N/L
ACGIH TLV:	0.46ppm SKIN	N/L
ACGIH STEL:	N/L	N/L
Carcinogenic Listing*:	N/L	N/L
Concentration by Wt./Mol%:	Min=83.0, Max=100.0	Max=17.0

1* = OSHA 2 = IARC 3 = NTP 4 = Others N/L = Not Listed
See Section 11 for more information

SECTION 3: HAZARD IDENTIFICATION

Emergency Overview:	The purpose of this MSDS is to transmit important product safety information. Please review this information with those who will use the product. For specific details on a particular product, please consult the technical data sheet.
Signal Word:	WARNING!
Hazards:	CAUSES SEVERE EYE AND SKIN BURNS. Prolonged and repeated skin contact or inhalation can cause liver, kidney, or brain damage and blood changes.
Physical State:	Liquid
Color:	
Odor:	Ammonia-like

Odor Threshold:	No value available
Potential Health Effects	
Routes of Exposure:	Ingestion, Skin Contact, Eye Contact, Inhalation
Signs and Symptoms of Acute Exposure:	See component summary
Diethanolamine:	Material is corrosive to the eyes, the vapor irritates the eyes, skin and respiratory tract.
Skin:	Irritating to the skin, not a sensitizer.
Inhalation:	Vapors or mists from this material can irritate the nose, throat and lungs, and cause signs and symptoms of central nervous system (CNS) depression, depending on the concentration and duration of exposure.
Eye:	Contact with liquid may cause chemical burns of the eyes and may cause blindness without prompt treatment. The vapors are severly irritating to the eyes.
Ingestion:	May irritate the mouth, throat and stomach and may cause nausea, vomiting, diarrhea and restlessness. Toxic effects similar to those resulting from inhalation may occur. If aspirated into the lungs, it may cause chemical pneumonia.
Chronic Health Effects:	Prolonged and repeated exposure to vapors may cause damage to the CNS, lungs and kidneys.
Diethanolamine:	Repeated exposure may cause liver and kidney damage.
Conditions Aggravated By Exposure:	Any pre-existing disorders or diseased of the liver, kidneys, reproductive system, and blood. Certain sensitive individuals and individuals with respiratory impairments may be affected by exposure to components in the processing emissions.

SECTION 4: FIRST AID MEASURES

Take proper precautions to ensure your own health and safety before attempting rescue and providing first aid. For specific information refer to the Emergency Overview in Section 3 of this MSDS

Inhalation:	
Eye:	Immediately flush eyes with plenty of cool water for at least 15 minutes. Do not permit victim to rub eyes. Get medical attention immediately!
Skin:	Immediately remove excess chemical and contaminated clothing; thoroughly wash contaminated skin with mild soap and water. If irritation persists after washing, seek medical attention.

	Thoroughly clean contaminated clothing before reuse; discard contaminated leather goods (gloves, shoes, belts, wallets, etc.).
Ingestion:	NEVER GIVE ANYTHING BY MOUTH TO AN UNCONSCIOUS PERSON. Have patient drink several glasses of water then induce vomiting by having patient tickle back of throat with finger.

SECTION 5: FIRE FIGHTING MEASURES

NFPA:	Health 1; Fire 1; Reactivity 0; Others:
Flammability Classification:	OSHA/NFPA Class IIIB combustible liquid.
Flash Point/Method:	> 138°C (>200°F) PMCC (Please refer to the product specification sheet for specific data).
Auto-Ignition Temperature:	662°C (1,224°F) (Please refer to the product specification sheet for specific data).
Flammable Limits:	LOWER: No Data Available. UPPER: No Data Available.
Hazardous Combustion Products:	Carbon oxides (CO, CO_2)
Special Conditions to Avoid:	Oxides of nitrogen will be evolved.
Extinguishing Media:	Use dry chemical, foam or carbon dioxide.
Fire Fighting Instructions:	Protective Equipment/Clothing: Wear an approved positive pressure self-contained breathing apparatus and firefighting turnout gear. INSTRUCTIONS: Water may be ineffective, but should be used to keep fire-exposed containers cool.

SECTION 6: ACCIDENTAL RELEASE MEASURES

Release Response:	Contain spill with dike to prevent entry into sewers or waterways. For large spills, dike and pump into properly labeled containers for reclamation or disposal. For small spills, soak up with absorbent material and place in properly labeled containers for disposal. All recovered material should be packaged, labeled, transported and disposed of or reclaimed in conformance with applicable laws and regulations and in conformance with good engineering practices. Reclaim where possible.
Reportable Quantities:	See Section 15: Regulatory Information.

SECTION 7: HANDLING AND STORAGE

Handling:	Containers, even those that have been emptied, will retain product residue and vapor and should be handled as if they were full. Do not eat, drink or smoke in areas where this material is used. After handling, always wash hands thoroughly with soap and water. Do not handle near heat, sparks or flame. Avoid contact with incompatible agents. Use only with adequate ventilation/personal protection. Avoid contact with eyes, skin and clothing. Do not enter storage areas unless adequately ventilated. Metal containers involved in the transfer of this material should be grounded and bonded.
Storage:	Store containers in a cool, dry, ventilated, fire resistant area away from sources of ignition and incompatible materials. Keep container tightly closed and properly labeled

SECTION 8: EXPOSURE CONTROLS AND PERSONAL PROTECTION

Engineering Controls:	Use process enclosures, local exhaust ventilation, or other engineering controls to keep airborne levels below recommended exposure limits. Emergency shower and eyewash facility should be in close proximity (ANSI Z358.1)
Personal Protection:	
Inhalation:	A respiratory protection program that meets OSHA's 29 CFR 1910.134 or ANSI Z88.2 requirements must be followed whenever workplace conditions warrant respirator use.
Skin:	Wear chemical resistant gloves such as: Rubber Neoprene, Nitrile or PVC. Appropriate protective clothing should be worn to prevent skin contact.
Eyes:	Wear safety glasses meeting the specifications of OSHA 29 CFR 1910.133/ANSI Standard Z87.1 where no contact with the eye is anticipated. Chemical safety goggles of this type should be worn whenever there is possibility of splashing or other contact with the eyes.

SECTION 9: PHYSICAL AND CHEMICAL PROPERTIES

Boiling Point:	100-268°C (212-516°F) (Please refer to the product specification sheet for specific data).	
Vapor Pressure:	<0.01 mm Hg @ 20°C	
pH:	11	
Viscosity:	352 mpsi	
Specific Gravity:	Solid/Liquid:	1.08 g/cc (Please refer to the product specification sheet for specific data) (Water=1)
	Vapor:	3.65 (Air=1.0)

Water Solubility:	Miscible
Octanol/Water Partition Coefficient in Kow:	-1.43 Estimated
Melting/Freezing Point:	-2.22°C (28°F) Water is added to Low Freeze Grades to depress freezing point.
Evaporation Rate:	No Data Available.

SECTION 10: STABILITY AND REACTIVITY

Chemical Stability:	The product is stable
Conditions to Avoid:	Avoid contact with strong oxidizers, excessive heat, sparks or open flame.
Incompatibility with:	Oxidizers, Acids, Alkalis
Hazardous Products Of Decomposition:	Carbon Monoxide and Carbon Dioxide. Ammonia and oxides of nitrogen.
Hazardous Polymerization:	Will not occur.
Reactions with Air & Water:	Does not react with air, water or other common materials.

SECTION 11: TOXICOLOGICAL INFORMATION

Product Summary: NTP has concluded that there is clear evidence of liver tumor and some evidence of kidney tumor in mice dermally exposed for their lifetime to DEA and TEA. The significance of these findings and their relevance to humans are not clear as neither DEA nor TEA were genotoxic (mutagenic nor clastogenic), and did not induce tumors in rats or in transgenic mice similarly treated. Additional research to better understand the significance of these observations to humans, if any is underway.

Rat	710 mg/kg
Rabbit	12200 mg/kg

ACUTE INHALATION EFFECTS: Due to low vapor pressure, significant exposure by inhalation appears unlikely. However, exposure to high concentrations of mist, aerosol, or vapors at elevated temperatures may cause irritation, coughing and discomfort in the nose, throat and chest.

ACUTE ORAL EFFECTS: May cause irritation of the mouth, throat, esophagus and stomach. Signs and symptoms may include pain, nausea, dizziness, faintness, weakness, collapse and coma.

Repeated Dose Toxicity: Repeated exposure may depress body weight and produce adverse changes in the kidneys and liver.

IMPORTANT: While Brenntag believes the information contained herein to be accurate, Brenntag makes no representation or warranty, express or implied, regarding, and assumes no liability for, the accuracy or completeness of the information. The Buyer assumes all responsibility for handling, using and/or reselling the Product in accordance with the applicable federal, state, and local law. This MSDS shall not in any way limit or preclude the operation and effect of any of the provisions of Brenntag's terms and conditions of sale.

CARCINOGENICITY: No conclusive data found in literature search.

Component Summary:
Diethanolamine

LD50 (Oral)	Rat	620 ul/kg
	Mouse	3300 mg/kg
LD50 (Skin)	Rabbit	7640 ul/kg

SKIN EFFECTS: Contact may cause mild skin irritation.

EYE EFFECTS: Corrosive to eyes.

SECTION 12: ECOLOGICAL INFORMATION

Ecotoxicity: This material is highly soluble in water. Laboratory toxicity tests indicate that is not significantly toxic to fish and aquatic invertebrates, although amphibians may be more sensitive. Wildlife species may be more susceptible since mammals and birds do not readily metabolize this material. The odor and flavor of this material may attract some wildlife and cause them to consume spilled material.

Environmental Fate: This material will biodegrade relatively rapidly in both soil and water, and will not persist in the environment. Due care should be taken to avoid accidental releases to aquatic or terrestrial systems.

Bioaccumulation: Because of this material's high solubility and rapid biodegradability, it is unlikely that bioaccumulation will occur in aquatic or terrestrial systems. Models estimate that this material will preferentially partition to water versus air or soil.

SECTION 13: DISPOSAL CONSIDERATIONS

Dispose of all waste and contaminated equipment in accordance with all applicable federal, state and local health and environmental regulations. Recovery and reuse, rather than disposal, should be the ultimate goal of handling efforts. The materials resulting from clean-up operations may be hazardous wastes and therefore, subject to specific regulations.

SECTION 14: TRANSPORT INFORMATION

Proper Shipping Name:
Environmentally Hazardous Substance, Liquid, n.o.s. (Diethanolamine)

DOT Hazard Class: 9

UN/NA ID:	UN 3082	Marine Pollutant:	No
Packaging Group:	PG III	NAER Guidebook:	171

Labels: Class 9 (miscellaneous hazardous material)

DOT Status: Regulated material. RQ: see section 15.

SECTION 15: REGULATORY INFORMATION

TSCA: All components of this product are listed or are exempt from listing on the TSCA 8(b) inventory. If identified components of this product are listed under the TSCA 12(b) Export Notification rule, they will be listed below.

TSCA 12(b) Component
Diethanolamine

SARA – Section 313 Emissions Reporting:

Component Summary	Reporting Threshold
Diethanolamine	1.0%

SARA – Section 311/312:

CERCLA Hazardous Substances and their Reportable Quantities:

Component Summary	Reportable Quantity
Diethanolamine	100 pounds (45.4 kg)

California Prop 65:
Proposition 65 requires manufacturers or distributors of consumer products into the State of California to provide a warning statement if the product contains ingredients for which the State has found to cause cancer, birth defects or other reproductive harm. If this product contains an ingredient listed by the State of California to cause cancer or reproductive toxicity it will be listed below.

SECTION 16: OTHER INFORMATION

DISCLAIMER OF RESPONSIBILITY: The information on this MSDS was obtained from sources which we believe are reliable. However, the information is provided without any warranty, expressed or implied, regarding its correctness. Some information presented and conclusions drawn herein are from sources other than direct test data on the substance itself. The conditions or methods of handling, storage, use and disposal of the product are beyond our control and may be beyond our knowledge. For this and other reasons, we do not assume responsibility and expressly disclaim liability for loss, damage, or expense arising out of or in any way connected with handling, storage, use or disposal of this product. If the product is used as a component in another product, this MSDS information may not be applicable.

Chemtherm 550 Hot Oil MSDS

Material Safety Data Sheet

Section 1. Chemical Product and Company Identification

Common Name	**Chemtherm 550**
Supplier	Coastal Chemical Co., L.L.C. 3520 Veterans Memorial Drive Abbeville, LA 70510 337-893-3862
Synonym	Paraffinic Oil Hot Oil & Heat Transfer Fluid
Trade name	Chemtherm 550
Material Uses	Heat Transfer Fluid
Manufacturer	Coastal Chemical Co., L.L.C. 3520 Veterans Memorial Drive Abbeville, LA 70510 337-893-3862

Code	35402
MSDS#	Not available.
Validation Date	**4/1/2004**
Print Date	4/1/2004
Responsible Name	**Charles Toups**

In Case of Emergency	Transportation Emergency Call CHEMTREC 800-424-9300 Other Infomation Call Charles Toups 337-261-0796

Section 2. Composition and Information on Ingredients

Name	CAS #	% by Weight	Exposure Limits
1) Heavy Hydrotreated Naphthenic Distillates (petroleum)	64742-52-5	100%	

Section 3. Hazards Identification

Physical State and Appearance	Liquid.
Emergency Overview	CAUTION! MAY CAUSE EYE IRRITATION. MAY CAUSE SKIN IRRITATION. May be harmful if swallowed. After handling, always wash hands thoroughly with soap and water. Store and use away from heat, sparks, open flame, or any other ignition source.
Routes of Entry	Skin contact.
Potential Acute Health Effects	
Eyes	May be irritating to the eyes.
Skin	May be irritating to skin and eyes.
Inhalation	Not available.
Ingestion	Not available.
Potential Chronic Health Effects	**CARCINOGENIC EFFECTS**: Not available. **MUTAGENIC EFFECTS**: Not available. **TERATOGENIC EFFECTS**: Not available.
Medical Conditions Aggravated by Overexposure:	Repeated or prolonged exposure is not known to aggravate medical condition.
Overexposure /Signs/Symptoms	Not available.

See Toxicological Information (section 11)

Continued on Next Page

Section 4. First Aid Measures

Eye Contact	Check for and remove any contact lenses. In case of contact, immediately flush eyes with plenty of water for at least 15 minutes. Get medical attention.
Skin Contact	In case of contact, immediately flush skin with plenty of water. Remove contaminated clothing and shoes. Wash clothing before reuse. Thoroughly clean shoes before reuse. Get medical attention.
Inhalation	If inhaled, remove to fresh air. If not breathing, give artificial respiration. If breathing is difficult, give oxygen. Get medical attention.
Ingestion	DO NOT induce vomiting. Seek medical attention.
Notes to Physician	Not available.

Section 5. Fire Fighting Measures

Flammability of the Product	May be combustible at high temperature.
Auto-ignition Temperature	700 F
Flash Points	OPEN CUP: 172.78°C (343°F) (Cleveland.).
Flammable Limits	Not available.
Products of Combustion	carbon oxides (CO, CO2) Expect other products of combustion depending on other material related to or involved in the fire.
Fire Hazards in Presence of Various Substances	COMBUSTIBLE. Slightly flammable to flammable in presence of open flames, sparks, heat, oxidizing materials, reducing materials, combustible materials.
Explosion Hazards in Presence of Various Substances	Risks of explosion of the product in presence of mechanical impact: Not available. Risks of explosion of the product in presence of static discharge: Not available.
Fire Fighting Media and Instructions	SMALL FIRE: Use DRY chemical powder. LARGE FIRE: Use water spray, fog or foam. Do not use water jet.
Protective Clothing (Fire)	Be sure to use an approved/certified respirator or equivalent.
Special Remarks on Fire Hazards	Not available.
Special Remarks on Explosion Hazards	Not available.

Section 6. Accidental Release Measures

Small Spill and Leak	Absorb with an inert material and put the spilled material in an appropriate waste disposal.
Large Spill and Leak	Absorb with an inert material and put the spilled material in an appropriate waste disposal. Finish cleaning by spreading water on the contaminated surface and allow to evacuate through the sanitary system.

Section 7. Handling and Storage

Handling	Avoid breathing vapors or spray mists.
Storage	Keep container tightly closed. Keep container in a cool, well-ventilated area.

Continued on Next Page

Section 8. Exposure Controls/Personal Protection

Engineering Controls	Provide exhaust ventilation or other engineering controls to keep the airborne concentrations of vapors below their respective threshold limit value. Ensure that eyewash stations and safety showers are proximal to the work-station location.
Personal Protection	
Eyes	Safety glasses.
Body	Lab coat.
Respiratory	Not applicable.
Hands	Gloves (impervious).
Feet	Not applicable.
Personal Protection in Case of a Large Spill	Splash goggles. Full suit. Boots. Gloves. Suggested protective clothing might not be sufficient; consult a specialist BEFORE handling this product.

Product Name	**Exposure Limits**
1) Heavy Hydrotreated Naphthenic Distillates (petroleum)	

Consult local authorities for acceptable exposure limits.

Section 9. Physical and Chemical Properties

Physical State and Appearance	Liquid.
Molecular Weight	Not applicable.
Molecular Formula	Not applicable.
pH (1% Soln/Water)	4;5
Boiling/Condensation Point	>274°C (525.2°F)
Melting/Freezing Point	Pour point -50 F
Critical Temperature	Not available.
Specific Gravity	0.9 (Water = 1)
Vapor Pressure	<0 kPa (@ 20°C)
Vapor Density	>5 (Air = 1)
Volatility	0% (v/v). 0% (w/w).
Odor Threshold	Not available.
Evaporation Rate	Not available.
VOC	0 (%)
Viscosity	4.5 cSt at 100 C / 212 F
LogK$_{ow}$	Not available.
Ionicity (in Water)	Not available.
Dispersion Properties	Not available.

Odor	Bland. (Slight.)
Taste	Not available.
Color	Colorless to light yellow. (Light.)

Continued on Next Page

Solubility	Insoluble in cold water, hot water.
Physical Chemical Comments	Not available.

Section 10. Stability and Reactivity

Stability and Reactivity	The product is stable.
Conditions of Instability	Not available.
Incompatibility with Various Substances	Not available.
Hazardous Decomposition Products	Not available.
Hazardous Polymerization	Will not occur.

Section 11. Toxicological Information

Toxicity to Animals	LD50: Not available. LC50: Not available.
Chronic Effects on Humans	Not available.
Other Toxic Effects on Humans	No specific information is available in our database regarding the other toxic effects of this material for humans.
Special Remarks on Toxicity to Animals	Not available.
Special Remarks on Chronic Effects on Humans	Not available.
Special Remarks on Other Toxic Effects on Humans	Not available.

Section 12. Ecological Information

Ecotoxicity	Not available.
BOD5 and COD	Not available.
Biodegradable/OECD	Not available.
Mobility	Not available.
	Not available.
Toxicity of the Products of Biodegradation	Not available.
Special Remarks on the Products of Biodegradation	Not available.

Section 13. Disposal Considerations

Waste Information	Waste must be disposed of in accordance with federal, state and local environmental control regulations.
Waste Stream	Not available.

Consult your local or regional authorities.

Continued on Next Page

Section 14. Transport Information

Shipping Description	Not a DOT controlled material (United States). Not regulated.
Reportable Quantity	Not available.
Marine Pollutant	Not available.
Special Provisions for Transport	Not applicable.

Section 15. Regulatory Information

HCS Classification	Not controlled under the HCS (United States).
U.S. Federal Regulations	TSCA 8(b) inventory: Chemtherm 550 SARA 302/304/311/312 extremely hazardous substances: No products were found. SARA 302/304 emergency planning and notification: No products were found. SARA 302/304/311/312 hazardous chemicals: No products were found. SARA 311/312 MSDS distribution - chemical inventory - hazard identification: No products were found. SARA 313 toxic chemical notification and release reporting: No products were found. Clean Water Act (CWA) 307: No products were found. Clean Water Act (CWA) 311: No products were found. Clean air act (CAA) 112 accidental release prevention: No products were found. Clean air act (CAA) 112 regulated flammable substances: No products were found. Clean air act (CAA) 112 regulated toxic substances: No products were found.
International Regulations	
EINECS	Not available.
DSCL (EEC)	This product is not classified according to the EU regulations.
International Lists	No products were found.
State Regulations	No products were found. California prop. 65: No products were found.

Section 16. Other Information

Label Requirements	MAY CAUSE EYE IRRITATION. MAY CAUSE SKIN IRRITATION. May be harmful if swallowed.

Hazardous Material Information System (U.S.A.)

Health	1
Fire Hazard	1
Reactivity	0
Personal Protection	B

National Fire Protection Association (U.S.A.)

References	Not available.
Other Special Considerations	Not available.

Continued on Next Page

Validated by Charles Toups on 4/1/2004.	**Verified by Charles Toups.** **Printed 4/1/2004.**

Emergency Phone :
Transportation Emergency Call
CHEMTREC 800-424-9300
Other Infomation Call
Charles Toups
337-261-0796

Notice to Reader

Inlet Feed Composition

FEEDSTOCKS

1. Feedstock compositions and approximate throughput for this project are expected as shown below:

Feed Composition, Conditions and Rates (Dry Basis, Standard Barrels)

DCP Jefferson County Fractionation Project – Y Grade Feed Composition, Throughput and Conditions			
Component/Characteristic	Low Ethane Feed (LV%)	Mid-Range Feed (LV%)	High Ethane Feed (LV%)
N2	0.010	0.010	0.010
CO2	0.090	0.075	0.060
Methane	0.720	0.605	0.490
Ethane	37.680	45.835	53.990
Propane	30.740	27.295	23.860
i-Butane	6.940	5.955	4.970
n-Butane	11.900	9.925	7.950
i-Pentane	3.970	3.425	2.880
n-Pentane	3.400	2.935	2.470
CycloPentane	0.220	0.190	0.160
n-Hexane	2.300	1.985	1.670
MethylCycloPentane	0.560	0.485	0.410
Benzene	0.220	0.190	0.160
CycloHexane	0.340	0.290	0.240
MethylCycloHexane	0.560	0.485	0.410
Toluene	0.220	0.190	0.160
Xylenes	0.110	0.095	0.080
Sulfur Compounds	0.020	0.030	0.030
TOTALS	100.000	100.000	100.000
Approx. Throughput - BPD	77,200	87,000	75,900
Corrosion, Copper Strip	No. 1	No. 1	No. 1
Free Water Content	None	None	None

Feed Temperature and Pressure

Delivery Pressure	450 - 500 psig
Delivery Temperature	70 - 100 °F

ATTACHMENT D

SUPPORTING BACT INFORMATION

CCS Cost Estimation Study

CO_2 Pipeline Cost Estimation Guidance

Denbury Green Pipeline Map

Good Combustion Practices

TCEQ Fugitive Guidance

CCS Cost Estimation Study

Table D-1
CCS Equipment Capital Cost Estimate[1]
CCS Cost Estimation Study
DCP Midstream - Jefferson County NGL Fractionation Plant

DIRECT COSTS, (DC)		
CO_2 Capture Efficiency		90%
Skid Equipment Cost 2012$		$41,504,000
Total Equipment Cost (A) - 2012$		$41,504,000
Instrumentation (10% x A)		$4,150,400
Sales tax (8.25% x A)		$3,424,100
Freight (5% x A)		$2,075,200
Purchased Equipment Cost, (B)		**$51,153,700**
Direct Installation Costs		
Foundation & Supports	0.08 x B	$4,092,300
Erection & Handling	0.14 x B	$7,161,500
Electrical	0.04 x B	$2,046,100
Piping	0.02 x B	$1,023,100
Insulation	0.01 x B	$511,500
Painting	0.01 x B	$511,500
Subtotal		**$15,346,000**
Site Preparation		As Required
Building		As Required
Total Direct Costs		**$66,499,700**
INDIRECT COSTS, (IC)		
Engineering	0.10 x B	$5,115,400
Construction and Field Expenses	0.05 x B	$2,557,700
Contractor Fee	0.10 x B	$5,115,400
Start-up	0.02 x B	$1,023,100
Performance Test	0.01 x B	$511,500
Contingencies	0.03 x B	$1,534,600
Other (ER, SPCC, RMP Plans)	other	$20,000
Total Indirect Costs		**$15,877,700**
TOTAL CAPITAL COSTS, (CC)		**$82,377,400**

[1] Reference: EPA Air Pollution Control Cost Manual, Sixth Edition - EPA/452/B-02-001, Section 4.2, Chapter 2

Table D-2
Operating Cost Estimate[1]
CCS Cost Estimation Study
DCP Midstream - SET Frac Plant

TOTAL CAPITAL COST		
CO_2 CCS Unit		$82,377,400
DIRECT OPERATING COST, $/yr		
Operating Labor		
Operators Labor, 8 hrs/shift, 3 shifts/day @ $32.50/hr		$284,700
Supervision, 15% of Operator		$42,700
Maintenance		
Analyzer Technician (0.5 hrs/day, 365 days/yr @ $33.47/hr)		$6,100
Utilities & Operating Expenses		
Electricity: (12 MWh)(8760 hrs)($0.07/kwh)		$7,358,400
Amine: (1.0 gal/hr)($1.00/gal)		$8,760
Total Direct Operating Cost, $/yr		**$7,700,660**
INDIRECT OPERATING COSTS, $/yr		
Overhead		
60% of operators, supervisors and maintenance labor and material		$200,100
Administrative charges	0.02 x CC	$1,647,500
Property Taxes	0.01 x CC	$823,800
Insurance	0.01 x CC	$823,800
Capital Recovery Cost, 10 years, 10% = 0.1628		$13,411,000
Total Indirect Operating Cost, $/yr		**$16,906,200**
TOTAL ANNUAL OPERATING COST		**$24,606,860**
CO_2 Emission Reduction (190,957 tpy @ 90%)		171,861.30
TOTAL ANNUALIZED COST, $/TON CO_2 REMOVED*		**$143**
*Excluding: Process Royalty Fees Permit Fees & Special Engineering for Permits Fuel Costs		

[1] Reference: EPA Air Pollution Control Cost Manual, Sixth Edition - EPA/452/B-02-001, Section 4.2, Chapter 2

Table D-3
CO_2 Pipeline Capital Cost Estimate[1]
CCS Cost Estimation Study
DCP Midstream - Jefferson County NGL Fractionation Plant

Pipeline diameter (in)	4
Pipeline Length (miles)	1.5

Pipeline Costs			
Cost Type	**Units**	**Formula**	**Cost**
Materials	$ Diameter (in) Length (mi)	\$64,632 + \$1.85 x L x (330.5 x D^2 + 686.7 x D + 26,960)	$ 161,742.57
Labor	$ Diameter (in) Length (mi)	\$341,627 + \$1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013)	$ 851,672.56
Miscellaneous	$ Diameter (in) Length (mi)	\$150,166+ \$1.58 x L x (8,417 x D + 7,234)	$ 247,103.74
Right of Way	$ Diameter (in) Length (mi)	\$48,037+ \$1.20 x L x (577 x D + 29,788)	$ 105,809.80
Other Capital			
Cost Type	**Units**	**Formula**	**Cost**
CO_2 Surge Tank	$	Fixed	$ 1,150,636.00
Pipeline Control System	$	Fixed	$ 110,632.00
O&M			
Cost Type	**Units**	**Formula**	**Cost**
Fixed O&M	$/mile/year	Fixed	$ 8,632.00

Total Capital Cost	$	$	2,627,596.67
Depreciation (Amortized over 10 Years at 10%)		$	427,641.36

Annual O&M	$	12,948.00
Depreciation	$	427,641.36
Annual Pipeline Costs	**$**	**440,589.36**
Annual CCS Equipment Costs	**$**	**24,606,860.00**
Total CCS Costs	**$**	**25,047,449.36**

Total Tons CO_2	190,957.00
Estimated Reduction	90%
Total CO_2 Sequestered	171,861.30

Cost Per Ton Reduction	**$**	**145.74**

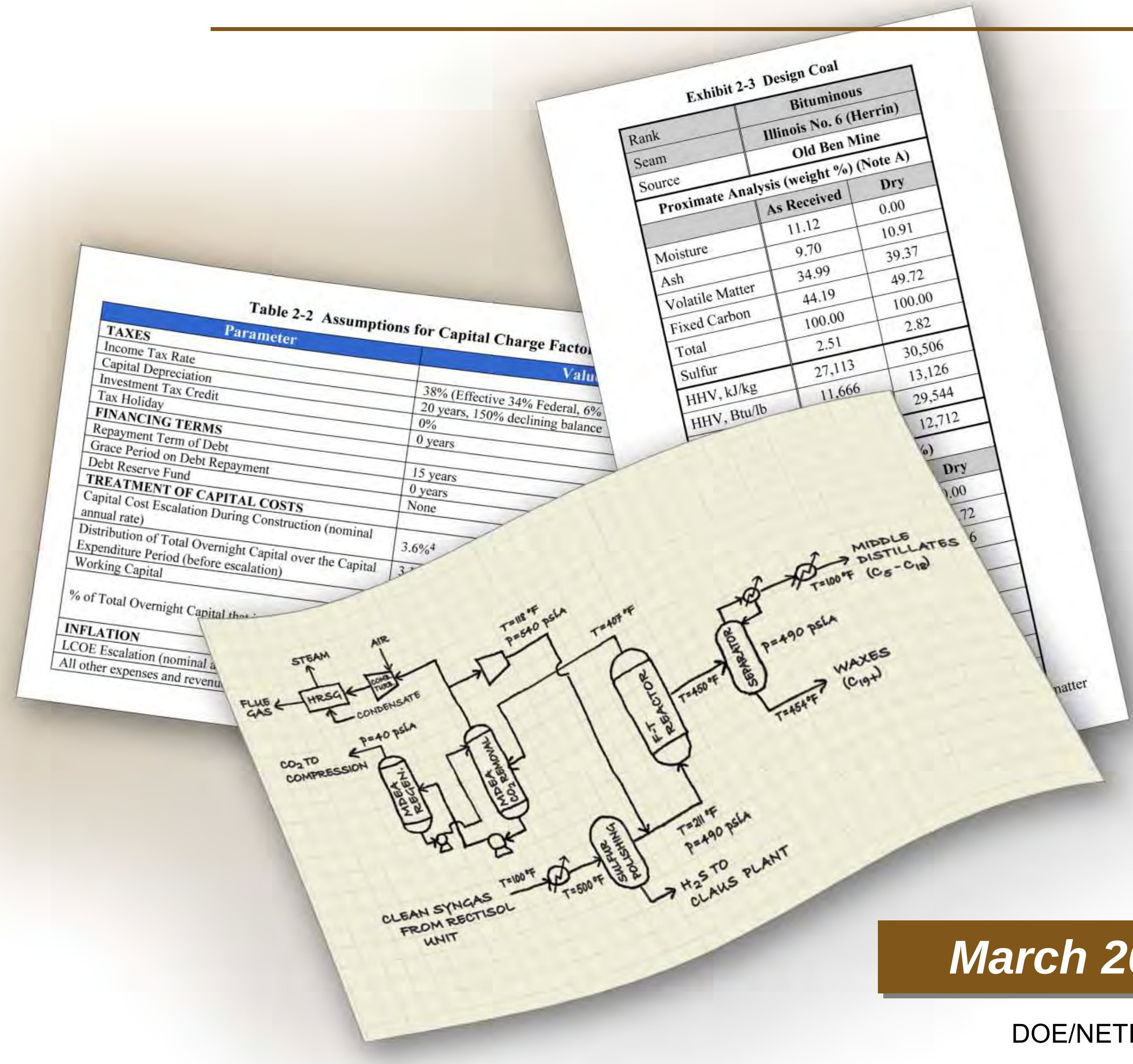
[1] Estimated using the National Energy Technology Laboratory's document "Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs." (DOE/NETL-2010/1447, March 2010)

CO_2 Pipeline Cost Estimation Guidance

the ENERGY lab

QUALITY GUIDELINES
FOR ENERGY SYSTEM STUDIES

Estimating Carbon Dioxide Transport and Storage Costs



March 2010

DOE/NETL-2010/1447

NATIONAL ENERGY TECHNOLOGY LABORATORY

U.S. DEPARTMENT OF ENERGY

Quality Guidelines for Energy Systems Studies

Estimating CO_2 Transport, Storage & Monitoring Costs

Background

This paper explores the costs associated with geologic sequestration of carbon dioxide (CO_2). This cost is often cited at the flat figure of $5-10 per short ton of CO_2 removed, but estimates can vary with values as high as $23 per short ton having been published recently [1, 2, 3]. The variability of these costs is due in part to the wide range of transportation and storage options available for CO_2 sequestration, but may also relate to the dramatic rise of construction and material costs in the United States which has occurred over the last several years. This paper examines the transportation of CO_2 via pipeline to, and storage of that CO_2 in, a geologic formation representative of those identified in North America as having storage potential based on data available from the literature.

Approach

Geologic sequestration costs were assessed based on the pipeline transport and injection of super-critical CO_2 into a geologic reservoir representative of those identified in North America as having storage potential. High pressure (2,200 psig) CO_2 is provided by the power plant or energy conversion facility and the cost and energy requirements of compression are assumed by that entity. CO_2 is in a super-critical state at this pressure which is desirable for transportation and storage purposes.

CO_2 exits the pipeline terminus at a pressure of 1,200 psig, and the pipeline diameter was sized for this to be achieved without the need for recompression stages along the pipeline length. This exit pressure specification: (1) ensures that CO_2 remains in a supercritical state throughout the length of the pipeline regardless of potential pressure drops due to pipeline elevation change[1]; (2) is equivalent to the reservoir pressure – exceeding it after hydrostatic head is accounted for – alleviating the need for recompression at the storage site; and (3) minimizes the pipeline diameter required, and in turn, transport capital cost.

The required pipeline diameter was calculated iteratively by determining the diameter required to achieve a 1,000 psig pressure drop (2,200 psig inlet, 1,200 psig outlet) over the specified pipeline distance, and rounding up to the nearest even sized pipe diameter. The pipeline was sized based on the CO_2 output produced by the power plant when it is operating at full capacity (100% utilization factor) rather than the average capacity.

The storage site evaluated is a saline formation at a depth of 4,055 feet (1,236 meters) with a permeability of 22 md and down-hole pressure of 1,220 psig (8.4 MPa) [4].[2] This is considered an average storage site and requires roughly one injection well for each 10,300 short tons of CO_2 injected per day [4]. An overview of the geologic formation characteristics are shown in Table 1.

Table 1: Deep, Saline Formation Specification [4]

Parameter	Units	Average Case
Pressure	MPa (psi)	8.4 (1,220)
Thickness	m (ft)	161 (530)
Depth	m (ft)	1,236 (4,055)
Permeability	Md	22
Pipeline Distance	km (miles)	80 (50)
Injection Rate per Well	tonne (short ton) CO_2/day	9,360 (10,320)

---

[1] Changes in pipeline elevation can result in pipeline pressure reductions due to head losses, temperature variations or other factors. Therefore a 10% safety margin is maintained to ensure the CO_2 supercritical pressure of 1,070 psig is exceeded at all times.

[2] "md", or millidarcy, is a measure of permeability defined as 10^{-12} Darcy.

Cost Sources & Methodology

The cost metrics utilized in this study provide a best estimate of T, S, & M costs for a "typical" sequestration project, and may vary significantly based on variables such as terrain to be crossed by the pipeline, reservoir characteristics, and number of land owners from which sub-surface rights must be acquired. Raw capital and operating costs are derived from detailed cost metrics found in the literature, escalated to June 2007-year dollars using appropriate price indices. These costs were then verified against values quoted by any industrial sources available. Where regulatory uncertainty exists or costs are undefined, such as liability costs and the acquisition of underground pore volume, analogous existing policies were used for representative cost scenarios.

The following sections describe the sources and methodology used for each metric.

Cost Levelization and Sensitivity Cases

Capital costs were levelized over a 30-year period and include both process and project contingency factors. Operating costs were similarly levelized over a 30-year period and a sensitivity analysis was performed to determine the effects of different pipeline lengths on overall and avoided costs as well as the distribution of transport versus storage costs.

In several areas, such as Pore Volume Acquisition, Monitoring, and Liability, cost outlays occur over a longer time period, up to 100 years. In these cases a capital fund is established based on the net present value of the cost outlay, and this fund is then levelized as described in the previous paragraph.

Following the determination of cost metrics, a range of CO_2 sequestration rates and transport distances were assessed to determine cost sensitivity to these parameters. Costs were also assessed in terms of both removed and avoided emissions cost, which requires power plant specific information such as plant efficiency, capacity factor, and emission rates. This paper presents avoided and removed emission costs for both Pulverized Coal (PC) and Integrated Gasification Combined Cycle (IGCC) cases using data from Cases 11 & 12 (Supercritical PC with and without CO_2 Capture) and Cases 1 & 2 (GEE Gasifier with and without CO_2 Capture) from the *Bituminous Baseline Study* [5].

Transport Costs

CO_2 transport costs are broken down into three categories: pipeline costs, related capital expenditures, and O&M costs.

Pipeline costs are derived from data published in the Oil and Gas Journal's (O&GJ) annual Pipeline Economics Report for existing natural gas, oil, and petroleum pipeline project costs from 1991 to 2003. These costs are expected to be analogous to the cost of building a CO_2 pipeline, as noted in various studies [4, 6, 7]. The University of California performed a regression analysis to generate the following cost curves from the O&GJ data: (1) Pipeline Materials, (2) Direct Labor, (3) Indirect Costs[3], and (4) Right-of-way acquisition, with each represented as a function of pipeline length and diameter [7].

Related capital expenditures were based on the findings of a previous study funded by DOE/NETL, *Carbon Dioxide Sequestration in Saline Formations – Engineering and Economic Assessment* [6]. This study utilized a similar basis for pipeline costs (Oil and Gas Journal Pipeline cost data up to the year 2000) but added a CO_2 surge tank and pipeline control system to the project.

Transport O&M costs were assessed using metrics published in a second DOE/NETL sponsored report entitled *Economic Evaluation of CO_2 Storage and Sink Enhancement Options* [4]. This study was chosen due to the reporting of O&M costs in terms of pipeline length, whereas the other studies mentioned above either (a)

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[3] Indirect costs are inclusive of surveying, engineering, supervision, contingencies, allowances for funds used during construction, administration and overheads, and regulatory filing fees.

do not report operating costs, or (b) report them in absolute terms for one pipeline, as opposed to as a length- or diameter-based metric.

Storage Costs

Storage costs were broken down into five categories: (1) Site Screening and Evaluation, (2) Injection Wells, (3) Injection Equipment, (4) O&M Costs, and (5) Pore Volume Acquisition. With the exception of Pore Volume Acquisition, all of the costs were obtained from *Economic Evaluation of CO_2 Storage and Sink Enhancement Options* [4]. These costs include all of the costs associated with determining, developing, and maintaining a CO_2 storage location, including site evaluation, well drilling, and the capital equipment required for distributing and injecting CO_2.

Pore Volume Acquisition costs are the costs associated with acquiring rights to use the sub-surface area where the CO_2 will be stored, i.e. the pore space in the geologic formation. These costs were based on recent research by Carnegie Mellon University which examined existing sub-surface rights acquisition as it pertains to natural gas storage [8]. The regulatory uncertainty in this area combined with unknowns regarding the number and type (private or government) of property owners requires a number of “best engineering judgment” decisions to be made, as documented below under Cost Metrics.

Liability Protection

Liability Protection addresses the fact that if damages are caused by injection and long-term storage of CO_2, the injecting party may bear financial liability. Several types of liability protection schemas have been suggested for CO_2 storage, including Bonding, Insurance, and Federal Compensation Systems combined with either tort law (as with the Trans-Alaska Pipeline Fund), or with damage caps and preemption, as is used for nuclear energy under the Price Anderson Act [9].

At present, a specific liability regime has yet to be dictated either at a Federal or (to our knowledge) State level. However, certain state governments have enacted legislation which assigns liability to the injecting party, either in perpetuity (Wyoming) or until ten years after the cessation of injection operations, pending reservoir integrity certification, at which time liability is turned over to the state (North Dakota and Louisiana) [10, 11, 12]. In the case of Louisiana, a trust fund of five million dollars is established for each injector over the first ten years (120 months) of injection operations. This fund is then used by the state for CO_2 monitoring and, in the event of an at-fault incident, damage payments.

This study assumes that a bond must be purchased before injection operations are permitted in order to establish the ability and good will of an injector to address damages where they are deemed liable. A figure of five million dollars was used for the bond based on the Louisiana fund level. This Bond level may be conservative, in that the Louisiana fund covers both liability and monitoring, but that fund also pertains to a certified reservoir where injection operations have ceased, having a reduced risk compared to active operations. This cost may be updated as more specific liability regimes are instituted at the Federal or State levels. The Bond cost was not escalated.

Monitoring Costs

Monitoring costs were evaluated based on the methodology set forth in the IEA Greenhouse Gas R&D Programme’s *Overview of Monitoring Projects for Geologic Storage Projects* report [13]. In this scenario, operational monitoring of the CO_2 plume occurs over thirty years (during plant operation) and closure monitoring occurs for the following fifty years (for a total of eighty years). Monitoring is via electromagnetic (EM) survey, gravity survey, and periodic seismic survey, EM and gravity surveys are ongoing while seismic survey occurs in years 1, 2, 5, 10, 15, 20, 25, and 30 during the operational period, then in years 40, 50, 60, 70, and 80 after injection ceases.

Cost Metrics

The following sections detail the Transport, Storage, Monitoring, and Liability cost metrics used to determine CO_2 sequestration costs for the deep, saline formation described above. The cost escalation indices utilized to bring these metrics to June-2007 year dollars are also described below.

Transport Costs

The regression analysis performed by the University of California breaks down pipeline costs into four categories: (1) Materials, (2) Labor, (3) Miscellaneous, and (4) Right of Way. The Miscellaneous category is inclusive of costs such as surveying, engineering, supervision, contingencies, allowances, overhead, and filing fees [7]. These cost categories are reported individually as a function of pipeline diameter (in inches) and length (in miles) in Table 2 [7].

The escalated CO_2 surge tank and pipeline control system capital costs, as well as the Fixed O&M costs (as a function of pipeline length) are also listed in Table 2. Fixed O&M Costs are reported in terms of dollars per miles of pipeline per year.

Storage Costs

Storage costs were broken down into five categories: (1) Site Screening and Evaluation, (2) Injection Wells, (3) Injection Equipment, (4) O&M Costs, and (5) Pore Space Acquisition. Additionally, the cost of Liability Protection is also listed here for the sake of simplicity. Several storage costs are evaluated as flat fees, including Site Screening & Evaluation and the Liability Bond required for sequestration to take place.

As mentioned in the methodology section above, the site screening and evaluation figure of $4.7 million dollars is derived from *Economic Evaluation of CO_2 Storage and Sink Enhancement Options* [4]. Some sources in

Table 2: Pipeline Cost Breakdown [4, 6, 7]

Cost Type	Units	Cost
Pipeline Costs		
Materials	\$ *Diameter (inches), Length (miles)*	$\$64{,}632 + \$1.85 \times L \times (330.5 \times D^2 + 686.7 \times D + 26{,}960)$
Labor	\$ *Diameter (inches), Length (miles)*	$\$341{,}627 + \$1.85 \times L \times (343.2 \times D^2 + 2{,}074 \times D + 170{,}013)$
Miscellaneous	\$ *Diameter (inches), Length (miles)*	$\$150{,}166 + \$1.58 \times L \times (8{,}417 \times D + 7{,}234)$
Right of Way	\$ *Diameter (inches), Length (miles)*	$\$48{,}037 + \$1.20 \times L \times (577 \times D + 29{,}788)$
Other Capital		
CO_2 Surge Tank	\$	\$1,150,636
Pipeline Control System	\$	\$110,632
O&M		
Fixed O&M	\$/mile/year	\$8,632

industry, however, have quoted significantly higher costs for site screening and evaluation, on the magnitude of $100 to $120 million dollars. The higher cost may be reflective of a different criteria utilized in assessing costs, such as a different reservoir size – the reservoir assessed in the higher cost case could be large enough to serve 5 to 7 different injection projects – or uncertainty regarding the success rate in finding a suitable reservoir. Future analyses will examine the sensitivity of overall T, S, and M costs to higher site evaluation costs.

Pore Space Acquisition costs are based on acquiring long-term (100-year) lease rights and paying annual rent to land-owners once the CO_2 plume has reached their property. Rights are acquired by paying a one-time $500 fee to land-owners before injection begins, as per CMU's design criteria [8]. When the CO_2 plume enters into the area owned by that owner (as determined by annual monitoring), the injector begins paying an annual "rent" of $100 per acre to that owner for the period of up to 100 years from plant start-up [8]. A 3% annual escalation rate is assumed for rental rate over the 100-year rental period [8]. Similar to the CMU study, this study assumes that the plume area will cover rights need to be acquired from 120 landowners, however, a sensitivity analysis found that the overall acquisition costs were not significantly affected by this: increasing the

Table 3: Geologic Storage Costs [4, 8, 11]

Cost Type	Units	Cost
Capital		
Site Screening and Evaluation	$	$4,738,488
Injection Wells	$/injection well *(see formula)*[1,2,3]	$\$240,714 \times e^{0.0008 \times well-depth}$
Injection Equipment	$/injection well *(see formula)*[2]	$\$94,029 \times \left(\frac{7,389}{280 \times \# of\ injection\ wells}\right)^{0.5}$
Liability Bond	$	$5,000,000
Declining Capital Funds		
Pore Space Acquisition	$/short ton CO_2	$0.334/short ton CO_2
O&M		
Normal Daily Expenses (Fixed O&M)	$/injection well	$11,566
Consumables (Variable O&M)	$/yr/short ton CO_2/day	$2,995
Surface Maintenance (Fixed O&M)	*see formula*	$\$23,478 \times \left(\frac{7,389}{280 \times \# of\ injection\ wells}\right)^{0.5}$
Subsurface Maintenance (Fixed O&M)	$/ft-depth/inject. well	$7.08

[1] The units for the "well depth" term in the formula are meters of depth.
[2] The formulas at right describe the cost per injection well and in each case the number of injection wells should be multiplied the formula in order to determine the overall capital cost.
[3] The injection well cost is $508,652 per injection well for the 1,236 meter deep geologic reservoir assessed here.

number of owners to 120,000 resulted in a 110% increase in costs and a 1% increase in the overall LCOE of the plant [8]. However, this assumption will be revisited in future work.

To ensure that Pore Space Acquisition costs are met after injection ceases, a sinking capital fund is set up to pay for these costs by determining the present value of the costs over the 100-year period (30 years of injection followed by 70 additional years), assuming a 10% discount rate. The size of this fund – as described in Table 3 – is determined by estimating the final size of the underground CO_2 plume, based on both the total amount of CO_2 injected over the plant lifetime and the reservoir characteristics described in Table 1. After injection, the CO_2 plume is assumed to grow by 1% per year [9].

The remaining capital costs are based on the number of injection wells required, which has been calculated to be one injection well for every 10,320 short tons of CO_2 injected per day. O&M costs are based on the number of injection wells, the CO_2 injection rates, and injection well depth.

Monitoring Costs

Monitoring costs were evaluated based on the methodology set forth in the IEA Greenhouse Gas R&D Programme's *Overview of Monitoring Projects for Geologic Storage Projects* report [13]. In this scenario, operational monitoring of the CO_2 plume occurs over thirty years (during plant operation) and closure monitoring occurs for the following fifty years (for a total of eighty years). Monitoring is via electromagnetic (EM) survey, gravity survey, and periodic seismic survey, EM and gravity surveys are ongoing while seismic survey occurs in years 1, 2, 5, 10, 15, 20, 25, and 30 during the operational period, then in years 40, 50, 60, 70, and 80 after injection ceases.

Operational and closure monitoring costs are assumed to be proportional to the plume size plus a fixed cost, with closure monitoring costs evaluated at half the value of the operational costs. The CO_2 plume is assumed to grow from 18 square kilometers (km^2) after the first year to 310 km^2 in after the 30th (and final) year of injection. The plume grows by 1% per year thereafter, to a size of 510 km^2 after the 80th year [9].The present value of the life-cycle costs is assessed at a 10% discount rate and a capital fund is set up to pay for these costs over the eighty year monitoring cycle. The present value of the capital fund is equivalent to $0.377 per short ton of CO_2 to be injected over the operational lifetime of the plant.

Cost Escalation

Four different cost escalation indices were utilized to escalate costs from the year-dollars they were originally reported in, to June 2007-year dollars. These are the Chemical Engineering Plant Cost Index (CEPI), U.S. Bureau of Labor Statistics (BLS) Producer Price Indices (PPI), Handy-Whitman Index of Public Utility Costs (HWI), and the Gross-Domestic Product (GDP) Chain-type Price Index [14, 15, 16].

Table 4 details which price index was used to escalate each cost metric, as well as the year-dollars the cost was originally reported in. Note that this reporting year is likely to be different that the year the cost estimate is from.

Cost Comparisons

The capital cost metrics used in this study result in a pipeline cost ranging from $65,000 to $91,000/inch-Diameter/mile for pipeline lengths of 250 and 10 miles (respectively) and 3 to 4 million metric tonnes of CO_2 sequestered per year. When project and process contingencies of 30% and 20% (respectively) are taken into account, this range increases to $97,000 to $137,000/inch-Diameter/mile. These costs were compared to contemporary pipeline costs quoted by industry experts such as Kinder-Morgan and Denbury Resources for verification purposes. Table 5 details typical rule-of-thumb costs for various terrains and scenarios as quoted by a representative of Kinder-Morgan at the Spring Coal Fleet Meeting in 2009. As shown, the base NETL cost metric falls midway between the costs quoted for "Flat, Dry" terrain ($50,000/inch-Diameter/mile) and "High Population" or "Marsh, Wetland" terrain ($100,000/inch-Diameter/mile), although the metric is closer to the "High Population" or "Marsh, Wetland" when contingencies are taken into account [17]. These costs were stated to be inclusive of right-of-way (ROW) costs.

Table 4: Summary of Cost Escalation Methodology

Cost Metric	Year-$	Index Utilized
Transport Costs		
Pipeline Materials	2000	HWI: Steel Distribution Pipe
Direct Labor (Pipeline)	2000	HWI: Steel Distribution Pipe
Indirect Costs (Pipeline)	2000	BLS: Support Activities for Oil & Gas Operations
Right-of-Way (Pipeline)	2000	GDP: Chain-type Price Index
CO_2 Surge Tank	2000	CEPI: Heat Exchangers & Tanks
Pipeline Control System	2000	CEPI: Process Instruments
Pipeline O&M (Fixed)	1999	BLS: Support Activities for Oil & Gas Operations
Storage Costs		
Site Screening/Evaluation	1999	BLS: Drilling Oil & Gas Wells
Injection Wells	1999	BLS: Drilling Oil & Gas Wells
Injection Equipment	1999	HWI: Steel Distribution Pipe
Liability Bond	2008	n/a
Pore Space Acquisition	2008	GDP: Chain-type Price Index
Normal Daily Expenses (Fixed)	1999	BLS: Support Activities for Oil & Gas Operations
Consumables (Variable)	1999	BLS: Support Activities for Oil & Gas Operations
Surface Maintenance	1999	BLS: Support Activities for Oil & Gas Operations
Subsurface Maintenance	1999	BLS: Support Activities for Oil & Gas Operations
Monitoring		
Monitoring	2004	BLS: Support Activities for Oil & Gas Operations

Ronald T. Evans of Denbury Resources, Inc. provided a similar outlook, citing pipeline costs as ranging from $55,000/inch-Diameter/mile for a project completed in 2007, $80,000/inch-Diameter/mile for a recently completed pipeline in the Gulf Region (no wetlands or swamps), and $100,000/inch-Diameter/mile for a currently planned pipeline, with route obstacles and terrain issues cited as the reason for the inflated cost of that pipeline [18, 19]. Mr. Evans qualified these figures as escalated due to recent spikes in construction and material costs, quoting pipeline project costs of $30,000/inch-Diameter-mile as recent as 2006 [18, 19].

A second pipeline capital cost comparison was made with metrics published within the 2008 IEA report entitled *CO_2 Capture and Storage: A key carbon abatement option*. This report cites pipeline costs ranging from $22,000/inch-Diameter/mile to $49,000/inch-Diameter/mile (once escalated to December-2006 dollars), between 25% and 66% less than the lowest NETL metric of $65,000/inch-Diameter/mile [20].

The IEA report also presents two sets of flat figure geologic storage costs. The first figure is based on a 2005 Intergovernmental Panel on Climate Change report is similar to the flat figure quoted by other entities, citing

Table 5: Kinder-Morgan Pipeline Cost Metrics [17]

Terrain	Capital Cost ($/inch-Diameter/mile)
Flat, Dry	$50,000
Mountainous	$85,000
Marsh, Wetland	$100,000
River	$300,000
High Population	$100,000
Offshore (150’-200’ depth)	$700,000

storage costs ranging from \$0.40 to \$4.00 per short ton of CO_2 removed [20]. This figure is based on sequestration in a saline formation in North America.

A second range of costs is also reported, citing CO_2 sequestration costs as ranging from \$14 to \$23 per short ton of CO_2 [13]. This range is based on a Monte Carlo analysis of 300 gigatonnes (Gt) of CO_2 storage in North America [20]. This analysis is inclusive of all storage options (geologic, enhanced oil recovery, enhanced coal bed methane, etc.), some of which are relatively high cost. This methodology may provide a more accurate cost estimate for large-scale, long-term deployment of CCS, but is a very high estimate for storage options that will be used in the next 50 to 100 years. For example, 300 Gt of storage represents capacity to store CO_2 from the next ~150 years of coal generation (2,200 million metric tonnes CO_2 per year from coal in 2007, assuming 90% capture from all facilities), meaning that certain high cost reservoirs will not come into play for another 100 or 150 years. This \$14 to \$23 per short ton estimate was therefore not viewed as a representative comparison to the NETL metric.

Results

Figure 1 describes the capital costs associated with the T&S of 10,000 short tons of CO_2 per day (2.65 million metric tonnes per year) for pipelines of varying length. This storage rate requires one injection well and is representative of the CO_2 produced by a 380 MW_g super-critical pulverized coal power plant, assuming 90% of the CO_2 produced by the plant is captured. Figure 2 presents similar information for Fixed, Variable, and total (assuming 100% capacity) operating expenses. In both cases, storage costs remain constant as the CO_2 flow rate and reservoir parameters do not change. Also, transport costs – which are dependent on both pipeline length and diameter – constitute the majority of the combined transport and storage costs for pipelines greater than 50 miles in length.

The disproportionately high cost of CO_2 transport (compared to storage costs) shown in Figures 1 and 2, and the direct dependence of pipeline diameter on the transport capital cost, prompted investigation into the effects of pipeline distance and CO_2 flow rate on pipeline diameter. Figure 3 describes the minimum required pipeline diameter as a function of pipeline length, assuming a CO_2 flow rate of 10,000 short tons per day (at 100%

Figure 1: Capital Cost vs. Pipeline Length

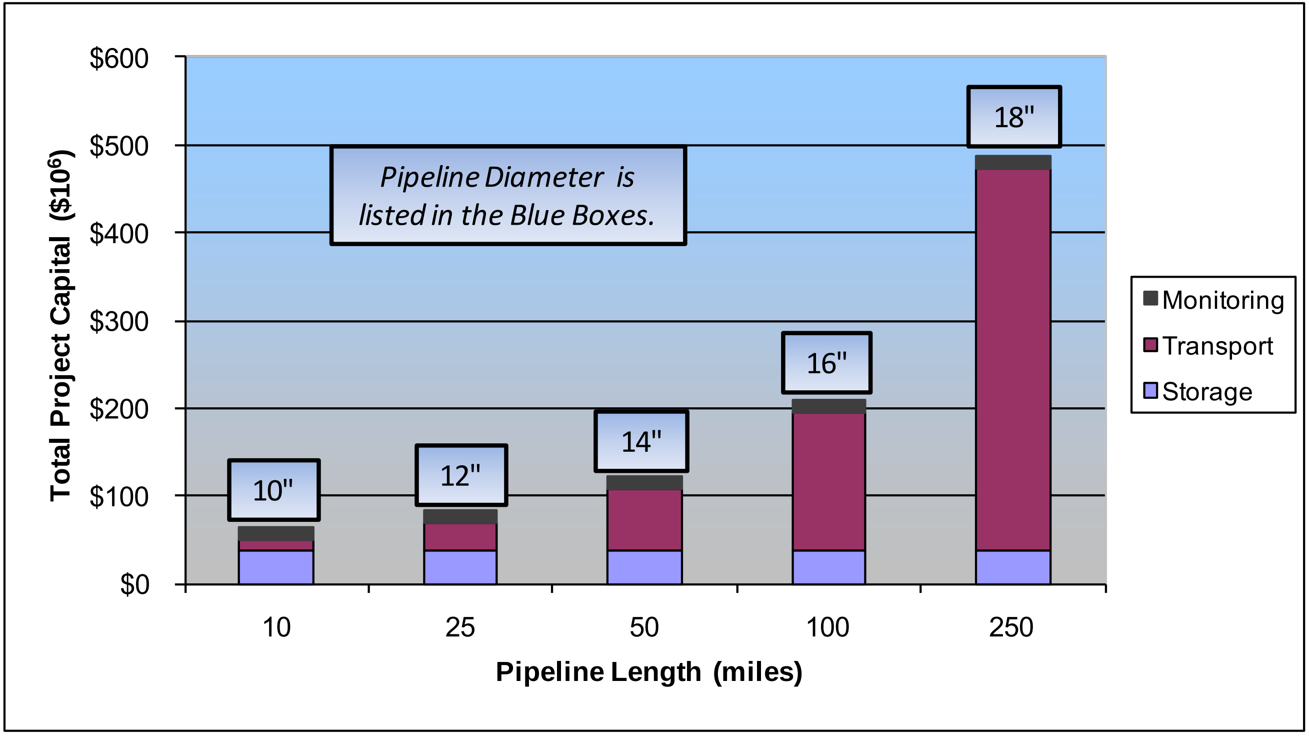
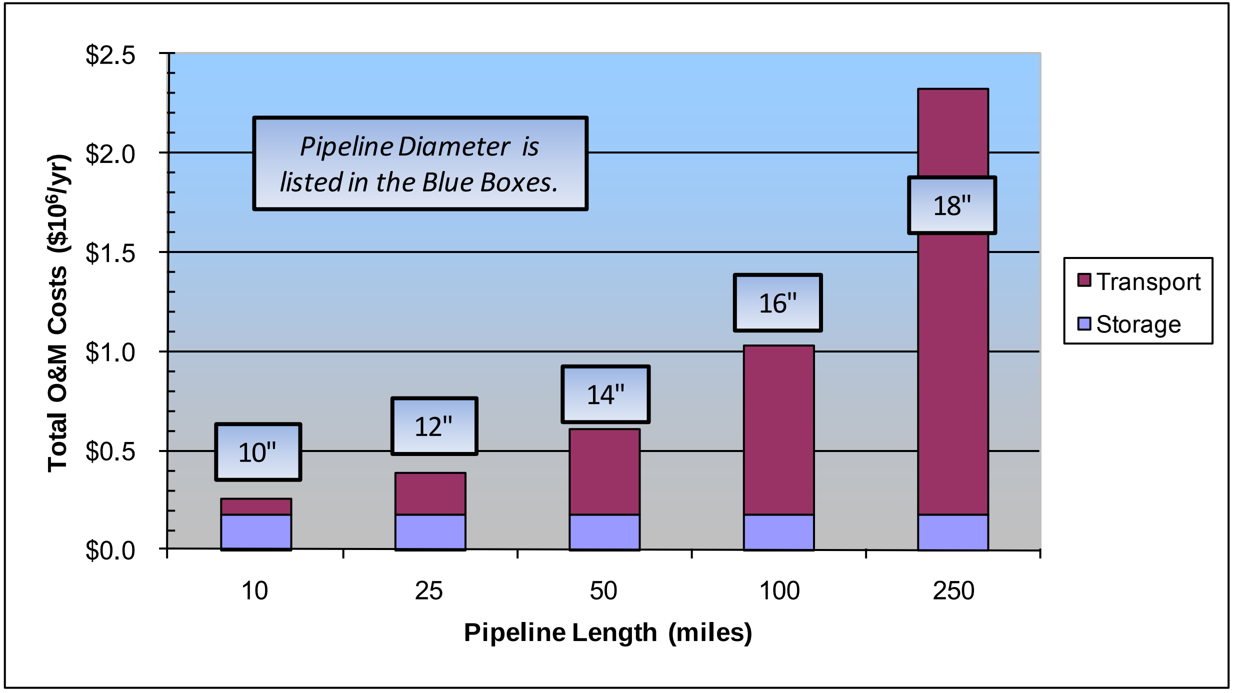


Figure 2: Operating and Maintenance Cost vs. Pipeline Length



utilization factor) and a pressure drop of 700 psi in order to maintain single phase flow in the pipeline (no recompression stages are utilized). Figure 4 is similar except that it describes the minimum pipe diameter as a function of CO_2 flow rate. A sensitivity analysis assessing the use of boost compressors and a smaller pipeline diameter has not yet been completed but may provide the ability to further reduce capital costs for sufficiently long pipelines.

Figure 3: Minimum Pipe Diameter as a function of Pipeline Length

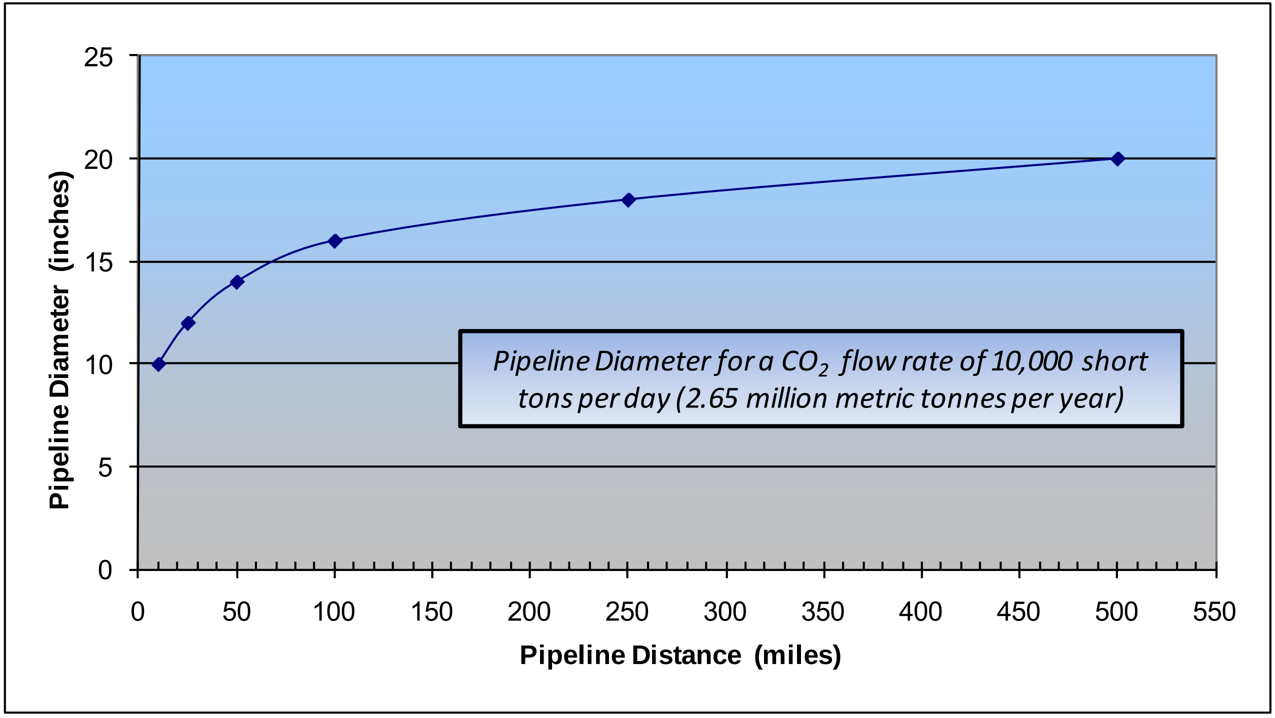
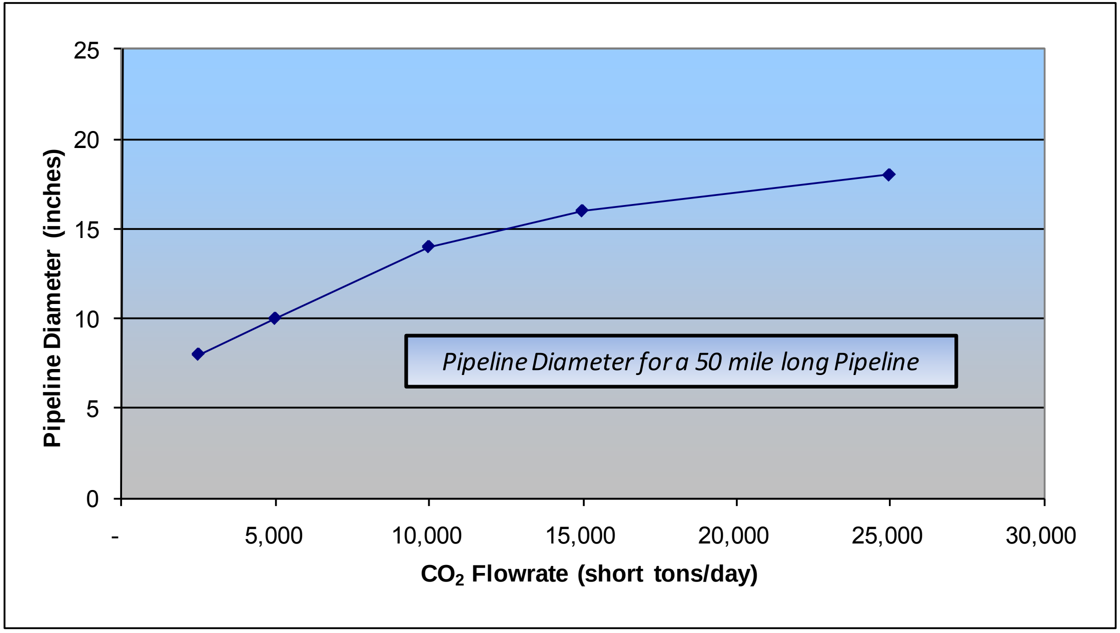


Figure 4: Pipe Diameter as a Function of CO_2 Flow Rate



Figures 5 and 6 describe the relationship of T&S costs to the flow rate of CO_2. The costs are evaluated for a 50 mile pipeline and a 700 psig CO_2 pressure drop over the length of the pipeline. Storage capital costs remain constant up until 10,000 short tons of CO_2 per day, above which a second injection well is needed and the cost increases as shown in Figure 5. A third injection well is needed for flow rates above 21,000 short tons per day and the capital requirement increases again for the 25,000 short tons per day flow rate due to an increase in pipeline diameter. Transport capital costs outweigh storage costs for all cases, as expected based on the results shown in Figure 1.

Unlike storage capital costs, the operating costs for storage constitute a significant portion of the total annual O&M costs – up to 44% at 25,000 short tons of CO_2 per day – as shown in Figure 6. Transport operating costs are constant with flow rate based on a constant pipeline length.

Figure 5: Capital Requirement vs. CO_2 Flow Rate

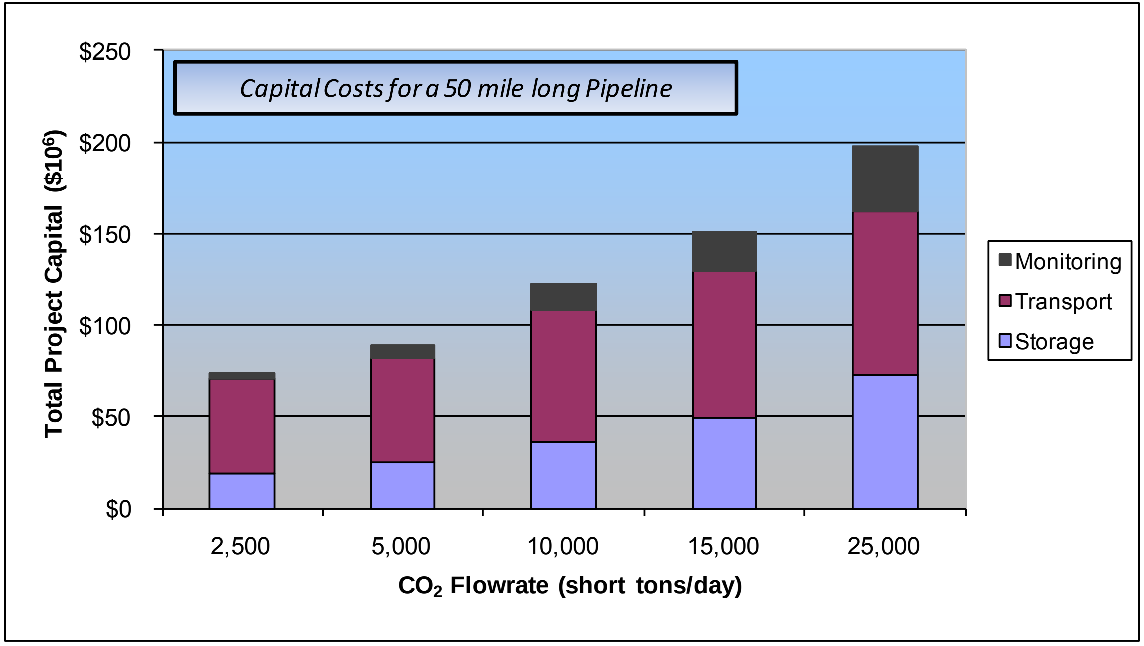
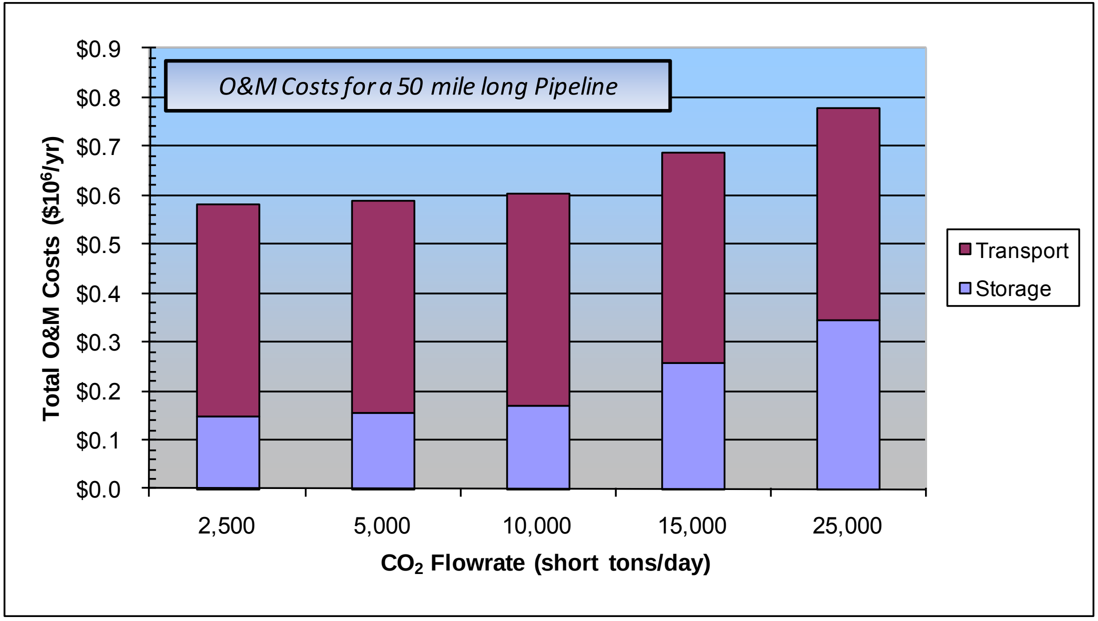
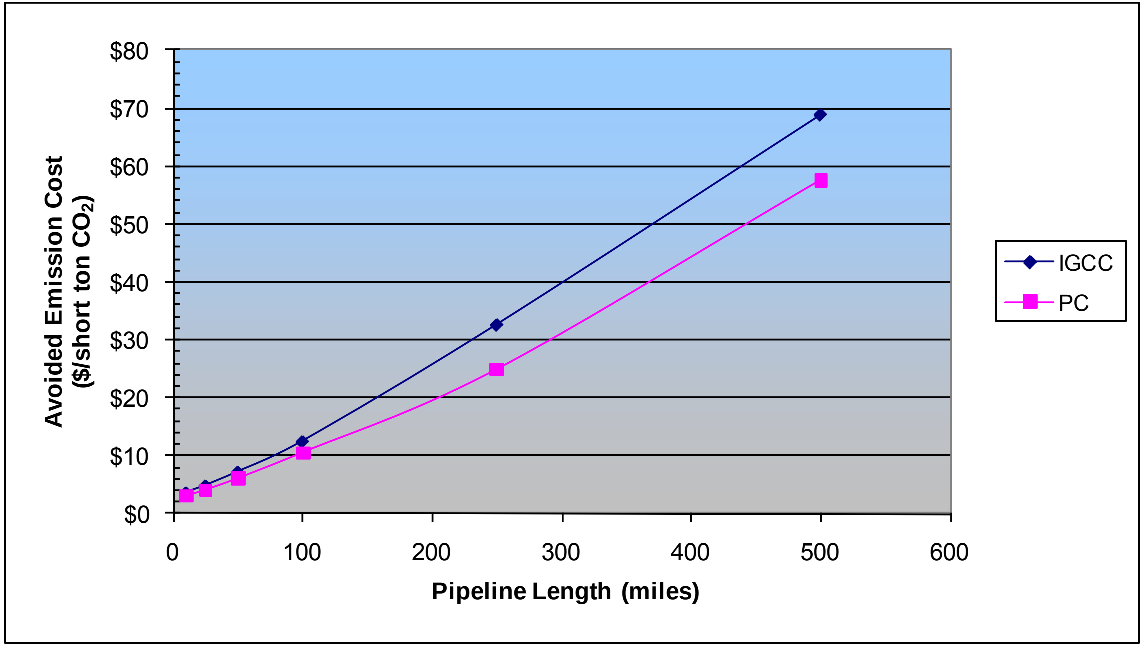


Figure 6: Operating and Maintenance Cost vs. CO_2 Flow Rate



Lastly, CO_2 avoidance and removal costs associated with T&S were determined for PC and IGCC reference plants found in the Baseline Study.[4] Because the CO_2 flow rate is defined by the reference plant, costs were determined as a function of pipeline length. Figure 7 shows that T&S avoided costs increase almost linearly with pipeline length and that there is very little difference between the PC and IGCC cases. This is the result of identical pipelines for each case (same distance, identical diameter) with only a change in capacity factor for each case. Figure 8 is similar to Figure 7 and shows the T&S removed emission cost.

Figure 7: Avoided Emission Costs for 550 MW Power Plants vs. Pipeline Length



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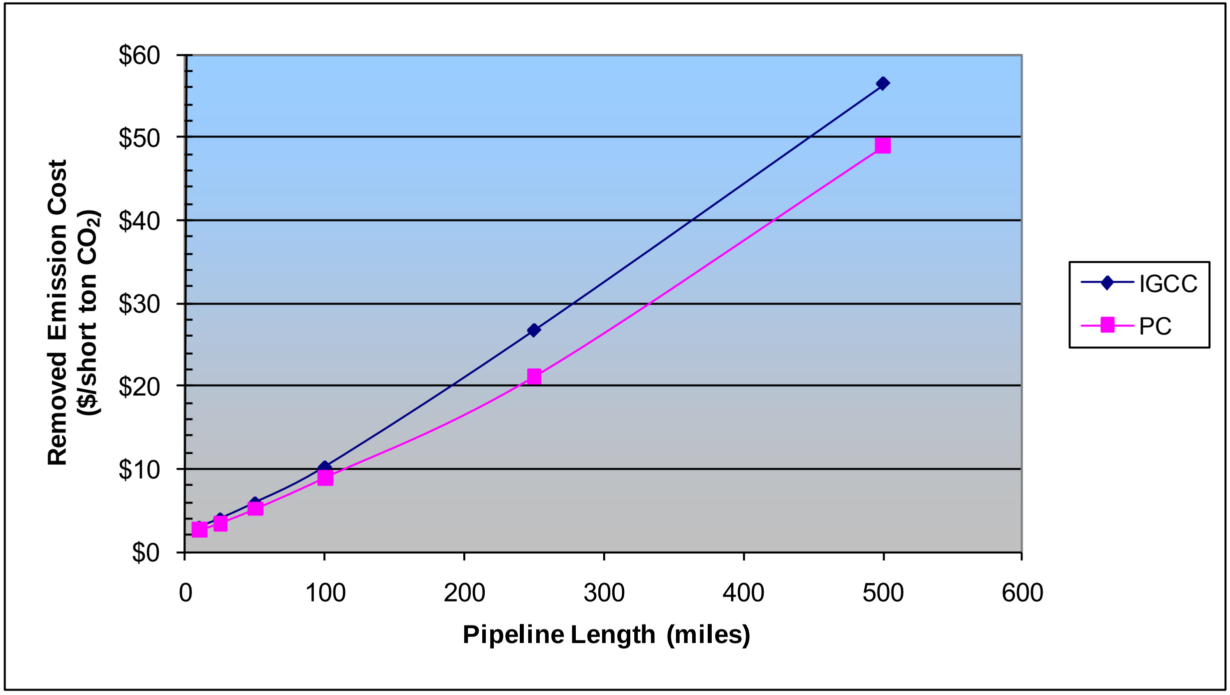
[4] Avoided cost calculations are based upon a levelized cost of electricity reported in Volume 1 of NETL's *Cost and Performance Baseline for Fossil Energy Plants* study. Electricity costs are levelized over a 30 year period, utilize a capital charge factor of 0.175, and levelization factors of 1.2022 and 1.1568 for coal costs and general O&M costs, respectively [3].

Addressing our initial topic, we see that our T&S avoided emission cost of \$5 to \$10 per short ton of CO_2 is associated with a pipeline length of 30 to 75 miles for the reference reservoir and our IGCC reference plant, or 50 to 95 miles for our PC reference plant. The T&S removal cost of \$5 to \$10 per short ton of CO_2 is associated with a pipeline length of 40 to 100 miles for an IGCC and 40 to 115 for a PC plant. Both of these ranges apply to the reference reservoir found in Table 1.

Figure 8: Removed Emission Costs for 550 MW Power Plants vs. Pipeline Length



Conclusions

- T&S avoided emission cost of \$5 to \$10 per short ton of CO_2 is associated with a pipeline length of 30 to 75 miles for our reference IGCC plant and the reference reservoir found in Table 1, or pipeline lengths of 50 to 95 miles for the PC plant.

- T&S removed emission cost of \$5 to \$10 per short ton of CO_2 is associated with a pipeline length of 40 to 100 miles for an IGCC and 40 to 115 for a PC plant. Both of these ranges apply to the reference reservoir found in Table 1.

- Capital costs associated with CO_2 storage become negligible compared to the cost of transport (i.e. pipeline cost) for pipelines of 50 miles or greater in length.

- Transport and storage operating costs are roughly equivalent for a 25 mile pipeline but transport constitutes a much greater portion of operating expenses at longer pipeline lengths.

- Transport capital requirements outweigh storage costs, independent of CO_2 flow rate, at a pipeline length of 50 miles and the reference reservoir.

- Operating expenses associated with storage approach transport operating costs for flow rates of 25,000 short tons of CO_2 per day at a 50 mile pipeline length.

Future Work

This paper has identified a number of areas for investigation in future work. These include:

- Investigation into the apparent wide variability in site characterization and evaluation costs, including a sensitivity analysis to be performed to determine the sensitivity of overall project costs across the reported range of values.

- Continued research into liability costs and requirements.

- Further evaluation and sensitivity analysis into the number of land-owners pore space rights will have to be acquired from for a given sequestration project.

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Contacts

Thomas J. Tarka, P.E.
Senior Energy Systems Engineer
Office of Systems, Analyses & Planning
National Energy Technology Laboratory
626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236
412-386-5434
thomas.tarka@netl.doe.gov

John G. Wimer
Director, Systems Division
Office of Systems, Analyses & Planning
National Energy Technology Laboratory
3601 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507
304-285-4124
john.wimer@netl.doe.gov

Denbury Green Pipeline Map


Harbor Island
Smith Island
College St
90
10
Clark Island
124
69
347
East Fwy
Fannett Rd
N Twin City Hwy
93
Neder
U.S. 69 Frontage Rd N
© 2013 Google
Google earth
Google earth
miles
10
km
10

Good Combustion Practices

GOOD COMBUSTION PRACTICES

This guidance is intended to be used by the source work groups in their evaluation of alternative concepts regarding good combustion practices. While operator training could also be considered a good combustion practice, it is covered by separate guidance.

Examples of practices listed are intended to indicate the range of existing practices which are dependent on the specific type of equipment utilized and the fuel/waste input to the combustion device. All examples of specific techniques are not considered applicable to all combustion sources. The source work groups should be requested to evaluate techniques, practices, and possible standard approaches appropriate for subcategories or other subsets of sources.

Periodic checks and adjustments of combustion equipment are intended to occur at intervals appropriate for the source, with key combustion checks timed no less frequent than to coincide with overhaul frequencies.

Good Combustion Technique	Examples of Practices	Applicable Source Types	Possible Standard
Operator practices	-Official documented operating procedures, updated as required for equipment or practice change -Procedures include startup, shutdown, malfunction -Operating logs/record keeping	All	-Maintain written site specific operating procedures in accordance with GCPs, including startup, shutdown, malfunction
Maintenance knowledge	-Training on applicable equipment & procedures	All	-Equipment maintained by personnel with training specific to equipment
Maintenance practices	-Official documented maintenance procedures, updated as required for equipment or practice change -Routinely scheduled evaluation, inspection, overhaul as appropriate for equipment involved -Maintenance logs/record keeping	All	-Maintain site specific procedures for best/optimum maintenance practices -Scheduled periodic evaluation, inspection, overhaul as appropriate

Good Combustion Technique	Examples of Practices	Applicable Source Types	Possible Standard
Stoichiometric (fuel/air) ratio	-Burner & control adjustment based on visual checks -Burner & control adjustment based on continuous or periodic monitoring (O2, CO, CO2) -Fuel/air metering, ratio control -Oxygen trim control -CO control -Safety interlocks	Open combustion	-SR limits appropriate for unit design & fuel -Routine & periodic adjustment -CO limit
Firebox (furnace) residence time, temperature, turbulence	-Supplemental stream injection into active flame zone -Residence time by design (incinerators) -Minimum combustion chamber temperature (incinerators)	-Open combustion with supplemental vent streams -Incinerators	
Proper liquid atomization	-Differential pressure between atomizing media & liquid -Flow ratio of atomizing media to liquid flow -Liquid temp or viscosity -Flame appearance -Atomizer condition -Atomizing media quality	Open combustion with liquid fuel/waste	-Routine & periodic adjustments & checks -Maintain procedures to ensure adequate atomization & mixing with combustion air
Fuel/waste quality (analysis); fuel/waste handling	-Monitor fuel/waste quality -Fuel quality certification from supplier if needed -Periodic fuel/waste sampling and analysis -Fuel/waste handling practices	All- where appropriate	-Fuel/waste analysis where composition could vary & of significance to HAP emissions (e.g., not pipeline natural gas) -Fuel/waste handling procedures applicable to the fuel/waste
Fuel/waste sizing	-Fuel/waste sizing specification & checks -Pulverized coal fineness checks	Solid fuel/waste firing	-Specification appropriate for fuel/waste fired -Periodic checks
Combustion air distribution	-Adjustment of air distribution system based on visual observations -Adjustment of air distribution based on continuous or periodic monitoring	Mainly stoker and solid fuel firing	-Routine & periodic adjustments & checks
Fuel/waste dispersion	-Adjustment based on visual observations	Solid fuel/waste firing	-Routine & periodic adjustments & checks

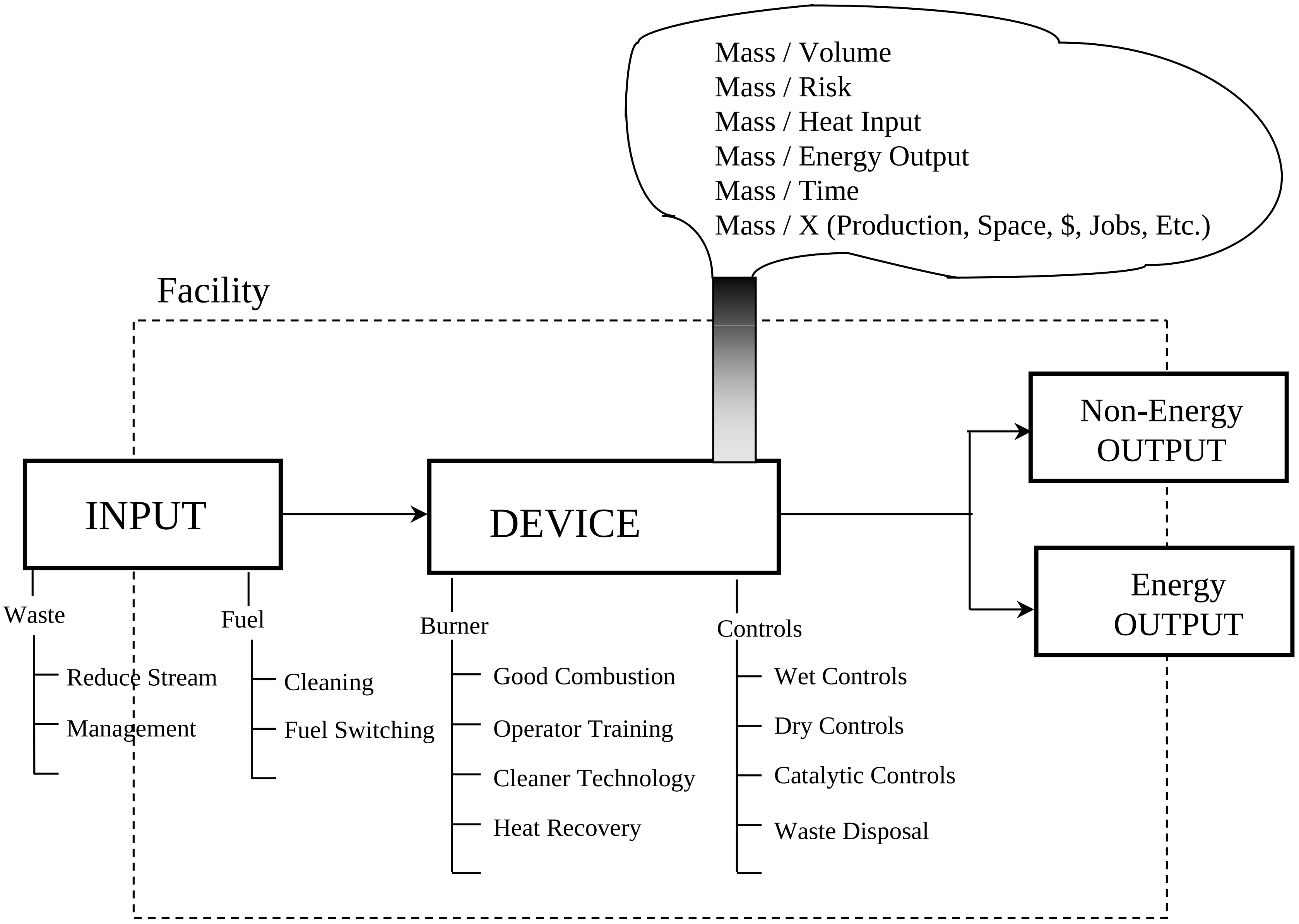
Mass / Volume
Mass / Risk
Mass / Heat Input
Mass / Energy Output
Mass / Time
Mass / X (Production, Space, $, Jobs, Etc.)
Facility
INPUT
DEVICE
Non-Energy OUTPUT
Energy OUTPUT
Waste
Reduce Stream
Management
Fuel
Cleaning
Fuel Switching
Burner
Good Combustion
Operator Training
Cleaner Technology
Heat Recovery
Controls
Wet Controls
Dry Controls
Catalytic Controls
Waste Disposal

FIGURE 1

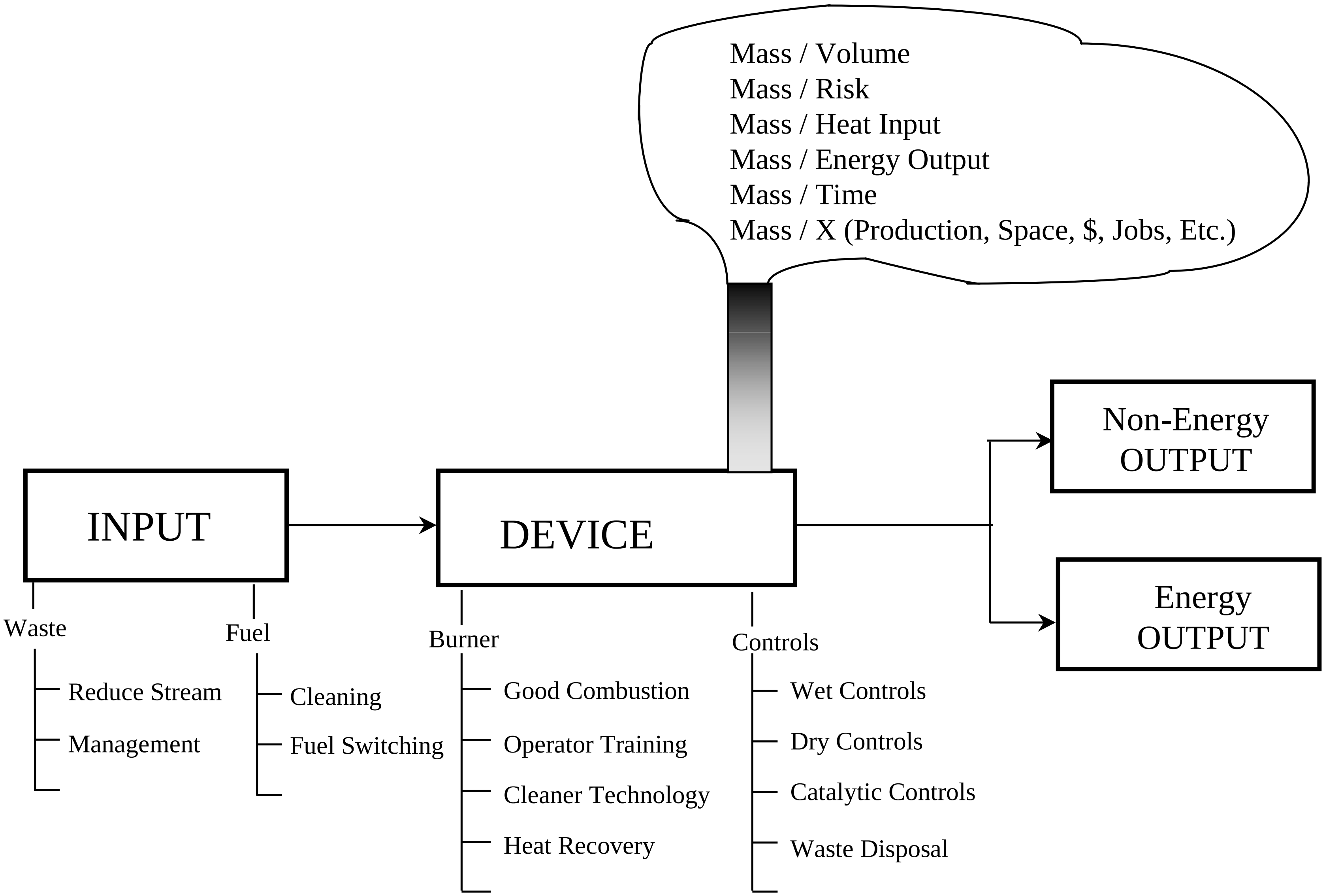
Mass / Volume
Mass / Risk
Mass / Heat Input
Mass / Energy Output
Mass / Time
Mass / X (Production, Space, $, Jobs, Etc.)
INPUT
DEVICE
Non-Energy OUTPUT
Energy OUTPUT
Waste
Reduce Stream
Management
Fuel
Cleaning
Fuel Switching
Burner
Good Combustion
Operator Training
Cleaner Technology
Heat Recovery
Controls
Wet Controls
Dry Controls
Catalytic Controls
Waste Disposal

FIGURE 2

TCEQ Fugitive Guidance

October 2000
Draft

TCEQ

Air Permit Technical Guidance for Chemical Sources:

Equipment Leak Fugitives

Air Permits Division
TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

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Paper

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TECHNICAL DISCLAIMER

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References to abatement technologies are not intended to represent minimum or maximum levels of BACT. Determinations of BACT are made on a case by case basis as part of the New Source Review of permit applications. BACT determinations are always subject to adjustment in consideration of specific process requirements, air quality concerns, and recent developments in abatement technology. Additionally, specific health effects concerns may indicate stricter abatement than required by the BACT determination.

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

The enclosed regulations are applicable as of the publication date of this package, but are subject to revision during the application preparation and review period. It is the responsibility of applicants to remain abreast of regulation developments which may affect their industries.

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

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

EQUIPMENT LEAK FUGITIVES

This document is intended to aid the permit applicant in the preparation of a technically complete permit application. The fugitive emissions discussed in this standardization package refer to the emissions from piping components and associated equipment including valves, connectors, pumps, compressor seals, relief valves, sampling connections, process drains, and open-ended lines. Uncaptured emissions emanating from other sources such as cooling towers, oil/water separators, material stockpiles, and loading operations are not addressed.

The TCEQ encourages pollution prevention, specifically source reduction, as a means of eliminating or reducing air emissions from industrial processes. The applicant should consider opportunities to prevent or reduce the generation of emissions at the source whenever possible through methods such as product substitutions, process changes, or training. Considering such opportunities prior to designing or applying “end-of-pipe” controls can not only reduce the generation of emissions, but may also provide potential reductions in subsequent control design requirements (e.g., size) and costs.

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I. REGULATIONS GOVERNING VOC EQUIPMENT LEAKS

A number of state and federal regulations exist that address volatile organic compounds (VOC) equipment leaks. All permit applications must demonstrate that a facility will be in compliance with all applicable Rules and Regulations. New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAPS and MACT) and TCEQ 30 TAC Chapter 115 have fugitive emission monitoring programs that vary depending on the specific industry, the material, and the county where the source is located. Each of the major fugitive emission monitoring programs required by state or federal regulation is listed below by industry type. For specific details, refer to the actual regulation in question.

PETROLEUM REFINERIES

30 TAC Chapter 115 (TCEQ Regulation V)

30 TAC § 115.352 Beaumont/Port Arthur, Dallas/Ft. Worth, Houston/Galveston and El Paso Areas

Leak definition of 10,000 ppmv for pump seals and compressors
Leak definition of 500 ppmv for all other components

30 TAC §115.322 Gregg, Nueces and Victoria Counties

Leak definition of 10,000 ppmv for all components

New Source Performance Standards (NSPS) (40 CFR Part 60)

40 CFR Part 60 Subpart GGG - Equipment Leaks of VOC in Petroleum Refineries (*Excluding those Subject to Subparts VV or KKK*)

National Emission Standards for Hazardous Air Pollutants (NESHAPS) (40 CFR Part 61)

Subpart J for benzene

Maximum Allowable Control Technology (MACT) (40 CFR 63)

Subpart CC - Petroleum Refineries

SYNTHETIC ORGANIC CHEMICALS MANUFACTURING INDUSTRY (SOCMI)

30 TAC Chapter 115 (TCEQ Regulation V)

30 TAC § 115.352	Beaumont/Port Arthur, Dallas/Ft. Worth, Houston/Galveston and El Paso Areas

Leak definition of 10,000 ppmv for pump seals and compressors

Leak definition of 500 ppmv for all other components

30 TAC § 115.322	Gregg, Nueces and Victoria Counties

Leak definition of 10,000 ppmv for all components

New Source Performance Standards (NSPS)

40 CFR Part 60 Subpart VV	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

National Emission Standards for Hazardous Air Pollutants (NESHAPS)

Subpart F for vinyl chloride, Subpart J for benzene

Hazardous Organic NESHAPS (HON)

Subpart H - Equipment Leaks

Subpart I - Certain Process Subject to the Negotiated Regulation for Equipment Leaks

NATURAL GAS PROCESSING

30 TAC Chapter 115 (TCEQ Regulation V)

30 TAC § 115.352	Beaumont/Port Arthur, Dallas/Ft. Worth, Houston/Galveston and El Paso Areas

Leak definition of 10,000 ppmv for pump seals and compressors

Leak definition of 500 ppmv for all other components

New Source Performance Standards (40 CFR Part 60)

Subpart KKK	Equipment Leaks of VOC from Onshore Natural Gas Processing Plants

(*Excluding those Covered Under Subparts VV or GGG*)

<u>Maximum Allowable Control Technology (MACT) (40 CFR Part 63)</u>

Subpart HH - Oil and Natural Gas Production Facilities

ADDITIONAL REQUIREMENTS

Please note that the regulations listed above are not an exhaustive list. New MACT standards are being proposed and promulgated that may contain LDAR requirements for specific industries. In addition, 30 TAC Chapter 115 may list fugitive emission inspection and monitoring requirements in sections other than those written specifically to address fugitive emissions. For example, fugitive inspection and maintenance requirements for marine terminals and gasoline terminals are contained in Section 115.214 of 30 TAC Chapter 115, Subchapter C, “Volatile Organic Compound Transfer Operations.”

II. QUANTIFYING UNCONTROLLED EMISSIONS

Fugitive emission rates are estimates based on leak frequencies found in case studies of chemical plants, oil and gas facilities, refineries and gasoline marketing terminals. An average leak factor is used to determine what the fugitive emission rate is for an area, a facility, or an entire plant. In general, there are five different sets of fugitive emission factors: (1) refinery factors, (2) oil and gas production operations factors, (3) SOCMI factors, (4) petroleum marketing terminal factors, and (5) derived factors used for specific compounds. Within each of the five sets, different factors are used to estimate the uncontrolled emission rates for each specific type of component (connectors, valves, pumps, etc.) and for the type of material in service (light liquid, heavy liquid, or gas/vapor). Each of the leak factors accepted by the TCEQ for use in permit applications is discussed below. The emission factors are provided on Attachment II.

SOCMI FACTORS

The SOCMI factors are generally for use in chemical plants including chemical processes that are located in a refinery. SOCMI factors are divided into three different sets which are applied in different situations.

The original SOCMI average factors were developed to represent fugitive emission rates from all chemical plants. The SOCMI average factors are found in EPA 453/R-95-017, page 2-12. From these factors, the TCEQ further derived two additional sets of factors: “SOCMI with ethylene” to be used for components in service of material which is greater than 85% ethylene, and ”SOCMI without ethylene" to be used where the ethylene concentration is less than 11%. For streams where the ethylene concentration is between 11% - 85%, the SOCMI average factors should be applied.

SOCMI NON-LEAKER FACTORS AND LOW VAPOR PRESSURE COMPOUNDS

Fugitive emissions from components in service where the material has a vapor pressure between 0.147 psia and 0.0147 psia should be estimated with the SOCMI Non-Leaker factors. The SOCMI Non-Leaker factors were developed from test data where no leaking emissions occurred above

10,000 ppmv; therefore, using the Non-Leaker factors assumes that no leaks will occur over the 10,000 ppmv leak detection threshold. For materials with a vapor pressure less than 0.0147 psia, fugitive emissions should be calculated using the SOCMI without ethylene factors with the Audio/Visual/Olfactory (AVO) reduction credits applied. In both cases, a weekly AVO inspection similar to the example condition given in Attachment I(E) will be required in the permit special conditions.

REFINERY FACTORS

Refinery factors are given in the Environmental Protection Agency's (EPA) Compilation of Air Pollutant Emission Factors, AP-42 (4th Edition), or EPA 453/R-95-017, page 2-13. Refinery factors are used when estimating fugitive emissions in a refinery process or production facility. A chemical process, such as a MTBE production unit, may be located in a refining facility but because it is not considered a refinery process, the refinery factors should not be used to calculate that specific unit's fugitive emissions.

PETROLEUM MARKETING TERMINAL FACTORS

In February of 1995 the Air Permits Division approved the use of the Petroleum Marketing Terminal Factors found in EPA document EPA-453/R-95-017, “Protocol for Equipment Leak Emission Estimates.” These factors are used to estimate fugitive emissions from components at gasoline distribution facilities that are one-step removed from local gasoline stations and other end-users. Although gasoline distribution facilities may also handle jet fuel and diesel, gasoline is their primary product. Loading racks at chemical plants and refineries may not use these factors. Use of the petroleum terminal factors is accompanied by an AVO LDAR program performed on a monthly basis as specified in a permit special condition similar to the example condition in Attachment I(F). The petroleum marketing terminal factors include the appropriate reduction credit for the AVO inspection; therefore, no additional reductions to the factors are necessary. The decision to require an AVO program instead of an instrument inspection was based on the EPA/API bagging study of various gasoline distribution facilities employing a variety of LDAR programs. The results of the study indicated that little or no improvement in fugitive emission control was achieved when an instrument was used to detect leaks at this type of facility.

OIL AND GAS PRODUCTION OPERATIONS FACTORS

The Oil and Gas Production factors are based on EPA evaluated data on equipment leak emissions from the oil and gas production industry gathered by the American Petroleum Institute (API). There are four different equipment service categories covered by the Oil and Gas Production factors: Gas, Heavy Oil (< 20˚ API gravity), Light Oil (> 20˚ API gravity), and Water/Light Oil (water streams in light oil service with a water content between 50% and 99%). The gas factors estimate total hydrocarbon emissions; therefore, the calculated emission rates must be multiplied by the weight percentage of C3+ compounds in the gas stream to get a total VOC rate for permitting purposes. It is important to note that the Oil and Gas Production Operations gas factors replace the Gas Plant Fugitive Factors from the previous EPA protocol document (EPA-453/R-93-026).

Operators of crude oil pipeline facilities which handle weathered or "dead" crude may use the Oil and Gas Heavy Oil (< 20˚ API gravity) factors to estimate fugitive emissions. This decision was based upon technical demonstrations by the industry that weathered crude is free of the entrained gases and easily volatilized light ends which affected the fugitive emissions factors based upon studies at tank batteries and other upstream facilities.

PHOSGENE, BUTADIENE, AND ETHYLENE OXIDE FACTORS

Specific factors have been developed for use with components in phosgene, butadiene, and ethylene oxide service. These factors are used to estimate fugitive emissions from components in phosgene, butadiene, and ethylene oxide service when monitored with the 28MID Leak Detection and Repair Program at the following leak definitions:

Phosgene	50 ppmv
Butadiene	100 ppmv

Ethylene Oxide 500 ppmv

Note: the EO connector factor does not include instrument monitoring. An additional reduction credit can be taken if connector monitoring is required.

ODOROUS/INORGANIC COMPOUNDS

For odorous or toxic inorganic compounds such as chlorine (Cl_2), ammonia (NH_3), hydrogen sulfide (H_2S), hydrogen fluoride (HF), and hydrogen cyanide (HCN), fugitive emissions are calculated in the same manner as any VOC fugitive emissions according to the type of facility. Although the VOC emission factors were not developed specifically for use with inorganic compounds, they are presently the best tool available for estimating fugitive emissions of inorganics.

The calculated uncontrolled emission rates can be reduced according to the credit allowed by any monitoring program to be implemented at the facility. The emission rates of the inorganic compounds are determined through speciating (see Attachment IV) the calculated total emission rate by multiplying the total emission rate by the weight percent of each individual compound present in the stream. Note that there are no additional monitoring requirements for inorganic compounds if the maximum predicted off-property impact is acceptable. If it is expected that the leakage of these compounds would be detected by smell before an instrument monitoring device would register a leak, see Section III for information on reducing the emission rate of inorganic compounds through a physical inspection program.

LIGHT/HEAVY LIQUIDS

Several of the factors make a distinction between the leak rate for heavy liquids and light liquids. For purposes of choosing an emission factor, heavy liquids are defined as having a vapor pressure of 0.044 psia or less. Light liquids are the liquids with vapor pressures higher than 0.044 psia at 68˚F.

COMPONENTS EXEMPT FROM MONITORING REQUIREMENTS

Emissions from components exempt from monitoring requirements based on size, physical location at a facility, or low vapor pressure *MUST* be calculated and included in the estimated fugitive emission rate regardless of any monitoring exemptions. There are presently no exemptions based on component size in Regulation V for the ozone nonattainment counties as mandated by EPA. In Gregg, Nueces, and Victoria Counties, valves with a nominal size of two inches or less are exempt from monitoring provided that certain requirements are met.

None of the 28 Series Leak Detection and Repair (LDAR) programs requires instrument monitoring of valves less than two inches in diameter; however, if the facility is located in an ozone nonattainment county and is subject to monitoring under 30 TAC 115.352, the two inch exemption will be removed from the permit conditions to be consistent with the regulation. In addition, certain non-accessible components, as defined in 30 TAC Chapter 115, are exempt from monitoring requirements. Monitoring requirements also vary depending on the vapor pressure of the compound. Fugitive emissions from components in heavy liquid service may be exempt from monitoring; however, the uncontrolled emissions must still be estimated.

SCREWED FITTINGS, LIQUID RELIEF VALVES, AND NON-EMITTING SOURCES

Factors have not been developed for certain types of piping components. In order to ensure consistency the TCEQ has designated the factor of a component with similar characteristics to be used to estimate fugitive emissions as follows:

I. Emissions from screwed fittings should be estimated in the same manner as flanges.

II. Emissions from liquid relief valves should be estimated in the same manner as light liquid valves.

III. Emissions from agitators should be estimated in the same manner as light liquid pumps.

Fugitive emissions should not be estimated from the following sources:

1) Tubing size lines (flexible lines ≤ 0.5’’ in diameter) and equipment if they are not subject to monitoring by any federal or state regulation

2) Non-piping type fittings (swedgelock or ferrule fittings),
3) Streams where the operating pressure is at least 0.7 psi below ambient pressure,
4) Mixtures in streams where the VOC has an aggregate partial pressure of less than 0.002 psi at 68° Fahrenheit.

**Regardless of the guidance given above, if a piping component is required to be monitored by a state or federal regulation, the fugitive emissions from that component must be estimated.

PROCESS DRAINS

Facilities subject to fugitive emission monitoring under 30 TAC §§115.322 and 352 are required to monitor process drains on an annual basis. A 75 percent reduction credit may be applied for annual monitoring of process drains at a leak threshold of 500 ppmv provided the drain is designed in such a manner that repairs to leaking drains can be achieved. For example, flushing a water seal on a leaking process drain would constitute repair, so a 75 percent reduction credit may be applied.

At present, the Refinery Factors are the only set of accepted emission factors that include a factor for fugitive emissions from process drains. This factor may be applied to any process drain regardless of facility or industry type.

HOURS OF OPERATION

Fugitive emission factors are independent of process unit throughput and are assumed to occur if there is material in the line, regardless of the activity of the process. Because fugitive emissions occur when there is material in the line, the hours in service for all streams should always be 8,760 hours annually regardless of process downtime. Any exception to this service time would require a permit condition requiring the lines to be purged during process downtime.

CORRELATION EQUATIONS AND PLANT SPECIFIC FACTORS

The use of various correlation equations developed by EPA for estimating fugitive emissions is not accepted for permitting purposes. Since actual monitoring data is required by the equations, they can be used for estimating actual emissions for emission inventory purposes.

Emission factors developed for individual facilities are also not accepted for permitting purposes. Such factors are the results of individual bagging studies which the TCEQ Air Permits Division does not have the resources to quality assure.

III. FUGITIVE EMISSION REDUCTION OPTIONS

There are two methods by which fugitive emission rates can be reduced: leak detection and repair (LDAR) programs and equipment specification.

LEAK DETECTION AND REPAIR (LDAR) PROGRAMS

Leak detection and repair programs can be differentiated by four key criteria:

1) Leak definition
2) Monitoring frequency
3) Properties of the monitored compounds
4) Requirements for repair

The leak definition is the monitored concentration, defined in ppmv, which identifies a leaking component needing repair.

The second criterion, monitoring frequency, varies depending on the component types and the LDAR program in place. Components typically must be monitored on a quarterly basis; however, some programs allow facilities to skip monitoring periods when the percentage of leaking components is maintained under a specified rate.

The third criterion involves LDAR programs which define the components to be monitored by the vapor pressure of the material in the component and the weight percent of VOC in the stream.

The fourth and final criterion is whether the program repair requirements are directed or non-directed maintenance. A directed maintenance program requires that a gas analyzer be used in conjunction with the repair or maintenance of leaking components to assure that a minimum leak concentration is achieved. If a replacement is required to fix a leaking component, the replaced component should be re-monitored within 15 days. A non-directed maintenance does not require the use of a gas analyzer during repair or maintenance of a leaking component.

40 CFR Part 60, 40 CFR Part 61, MACT and Chapter 115 all have LDAR programs required for specific industries, counties, and materials. Refer to Section I to determine if a facility must meet the requirements of these monitoring and repair programs. Also, remember that a facility may be subject to more than one monitoring program and that meeting the requirements of one program does not exempt a facility from the requirements of another. For example, a chemical plant in Harris County may be subject to the monitoring requirements of Regulation V and also have a permit containing the 28MID LDAR program.

There are five instrument assisted leak detection and repair programs to choose from for permitting purposes: 28M, 28RCT, 28VHP, 28MID and 28LAER. LDAR programs allow emission control credits for instrument monitored components and for the physical (AVO) inspection of connectors. These credits can only be given in cases where the components are actually inspected and for components for which the LDAR program could result in emission reductions. A 30% reduction of fugitive connector emission rates is allowed when a weekly AVO inspection is performed. As mentioned previously, components smaller than two inches not subject to fugitive monitoring by regulation are exempt from monitoring requirements. Instrument monitoring of connectors and components less than two inches can be given a reduction credit consistent with the LDAR program if additional emission reductions are needed or desired. The 28LAER LDAR program is used.

strictly to control fugitive emissions which are part of a non-attainment permit. For facilities which are not subject to a non-attainment permit, the same emission reductions may be attained by implementing the 28MID program in conjunction with the 28CNTA LDAR program for connectors.

In an effort to keep the LDAR programs used as permit special conditions as concise as possible, the procedures to justify delay of repair for a leaking component are not outlined in the 28 series LDAR programs and default to the requirements of 30 TAC Chapter 115. The 28 series LDAR programs also use the 30 TAC Chapter 115 definition for nonaccessible valves.

Each of the five instrument monitoring programs is outlined in Table 1.

Table I
Leak Detection and Repair (LDAR) Program Options

LDAR Program		**28M**	**28 RCT**	**28 VHP**	**28 MID**	**28 LAER**
Leak Definition	Pumps and Compressors	10,000 ppmv	10,000 ppmv	2,000 ppmv	500 ppmv	500 ppmv
	All Other Components	10,000 ppmv	500 ppmv	500 ppmv	500 ppmv	500 ppmv[2]
Applicable Vapor Pressure		> 0.5 psia at 100°F	> 0.044 psia at 68°F	> 0.044 psia at 68°F	> 0.044 psia at 68°F	> 0.044 psia at 68°F
Monitoring Frequency		Quarterly	Quarterly	Quarterly	Quarterly	Quarterly[2]
Directed/Nondirected Maintenance		Nondirected	Nondirected	Nondirected	Directed	Directed
Equivalent State/Federal Programs		40CFR Part 60/40 CFR Part 61	30 TAC 115.352[1]	MACT	N/A	Nonattainment NSR

1) Except in Gregg, Nueces, and Victoria Counties where 28 M applies.
2) Connectors are required to be monitored annually with an instrument under 28LAER.

LOW VAPOR PRESSURE COMPOUNDS

Compounds with low vapor pressures can present a problem with instrument monitoring. No reduction credits are allowed for valves and pumps in heavy liquid service under any of the five 28 Series LDAR programs or 30 TAC 115 as components in heavy liquid service are not required to be monitored. An applicant may propose to monitor these components and take the appropriate reduction credits as noted in Attachment III; however, the applicant must demonstrate that leaking components can be detected by implementing an instrument assisted fugitive monitoring program. For materials with vapor pressures below 0.147 psia, implementing a LDAR program with a 10,000 ppmv leak detection definition could be useless as leaking components may never be detected. For example, a component in heavy liquid service (vapor pressure < 0.044 psia) which is subject to a LDAR program with a leak definition of 10,000 ppmv would have a theoretical-saturation concentration of 0.044/14.7 = 2990 ppmv. Depending on the instrument response factor for the compounds being measured, this concentration may or may not be a measurable quantity; thus, it may not be possible to demonstrate an actual emission reduction via instrumental monitoring. These components would never get any increased maintenance or improved emission rates as a result of a LDAR Program with a 10,000 ppmv leak definition; therefore, these components cannot receive any reduction credit. To reduce these emissions, the applicant would have to commit to a 500 ppmv or 2,000 ppmv leak definition program.

AUDIO/VISUAL/OLFACTORY WALK-THROUGH INSPECTION

If the predicted off-property impact of an inorganic/odorous compound is unacceptable based on a predicted exceedance of an Effects Screening Level (ESL) or a maximum allowable ground level concentration specified in one of the regulations, the applicant will be required to commit to an Audio/Visual/Olfactory (AVO) walk-through inspection similar to the permit condition shown in Attachment I(E). Note that the repair time given in this condition may be extended on a case by case basis.

Inorganic/odorous compound fugitive emission rates controlled through the AVO inspection are determined as follows:

> The total number of components in service of the compound in question should be multiplied by the appropriate "SOCMI without ethylene" emission factor. The AVO reduction credits found in Attachment III should then be applied to the uncontrolled inorganic/odorous compound emission rates.

Please note that the AVO inspection program may only be applied to inorganic compounds for which instrument monitoring is not available. In limited instances the AVO inspection program may be applied to extremely odorous organic compounds, such as mercaptans.

REDUCTION CREDIT FOR ANNUAL AND QUARTERLY CONNECTOR MONITORING

Annual instrument monitoring of connectors at a 500 ppmv leak detection limit may receive a 75 percent reduction credit. This determination is based on information contained in the 1993 EPA document "Protocol for Equipment Leak Fugitives" and the results from a limited amount of monitoring data. The control effectiveness percentages given in the protocol document are based on the type of facility, monitored data, and the corresponding reduction in the percentage of leaking flanges. A lower common denominator was used to establish the appropriate reduction credit as it is preferable to allow a single reduction credit for both chemical facilities and refineries. Thus, the 75 percent reduction credit is suitable for use at both petroleum refineries and SOCMI facilities

where the flanges are monitored annually at 500 ppmv. The 28CNTA LDAR program specifies the monitoring and recordkeeping necessary to receive the 75 percent reduction credit. This program may be used in conjunction with any of the other 28 series LDAR programs.

Quarterly instrument monitoring of connectors at a 500 ppm leak detection limit may receive a 97 percent reduction credit. This credit is equivalent to that received by valves monitored at the same leak detection limit and frequency. Although in theory an applicant could monitor connectors quarterly at a 10,000 ppm leak detection limit with a 75 percent credit, there would be a greater benefit for the cost in moving to a more stringent leak definition for the valves and other components prior to implementing connector monitoring. The 28CNTQ LDAR program specifies the monitoring and recordkeeping necessary to receive the 97 percent reduction credit. This program may be used in conjunction with any of the other 28 series LDAR programs.

EQUIPMENT SPECIFICATION

There are certain options that may be implemented in the design of a facility to prevent fugitive emissions from escaping into the atmosphere. When calculating emission rates, various control credits may be applied to components in service as described below. Also, LDAR program monitoring for identified types of equipment is not required if 100 percent reduction credit is given.

Relief Valves

100% control may be taken if one of the following conditions is met:

1) Route relief valve vents to an operating control device
2) Equip with a rupture disc and pressure sensing device (between the valve and disc) to monitor for disc integrity

Note that for new facilities, BACT guidelines generally require that all relief valves vent to a control device.

Pumps

Certain types of pumps are designed to be "leakless" and as such can be given 100% control. Any of the following designs are accepted as leakless pumps:

1) Canned Pumps
2) Magnetic Drive Pumps
3) Diaphragm Pumps
4) Double mechanical seals and the use of a barrier fluid at a higher pressure than the process
5) Double mechanical seals and venting the barrier fluid seal pot to a control device

Valves

100% control may be taken if one of the following conditions is met:

1) Use of bellows valves with bellows welded to both the bonnet and stem
2) Use of diaphragm-type valves
3) Use of seal-welded, magnetically actuated, packless, hermetically sealed control valves

Connectors

Connectors may receive 100% control credit if the connections are welded together around the circumference of the connection such that the flanges are no longer capable of being disassembled by simply unbolting the flanges.

Compressors

Compressors must be designed with enclosed distance pieces and must have the crankcase venting to a control device to be given 100% control.

Double Mechanical Seals

Any component employing double mechanical seals may be given a 75% credit. If the seals are monitored, then use the appropriate monitoring credit.

DESIGN OPTIONS

There are certain options that may be incorporated into the design of a facility to minimize piping components, improve maintenance and/or reduce susceptibility to leaks. While some of these options may not result in reduction credits for fugitive emissions, they can result in lower maintenance costs and improved performance in some cases.

Overall

1) Design equipment layout to minimize pipe run lengths and associated connectors.
2) Minimize the use of valves and other components.
3) Minimize whenever possible the use of relief valves.
4) Optimize piping and component metallurgy for compatibility with process streams and/or physical environment to reduce corrosion potential.

Pumps

1) Use of pressure transfer to eliminate the need for pumps.
2) Use of submerged pumps which limit the exposure of potential leaks to the atmosphere.

Valves

1) Optimize length of time between leaks by using special packing sets and stringent adherence to packing procedures.
2) Use of on-line direct injection repair equipment.
   Note: This option may introduce an additional potential leak path for the valve if corrosion occurs around the tap.

Connectors

1) Eliminate the use of screwed fittings smaller than 2 inches in diameter.
   Note: BACT for fugitives does not allow the use of screwed connections greater than 2 inches in diameter.
2) Use of new technologies which have been deemed by the TCEQ to be equivalent to flanges.

Compressors

1) Designs with lower leak potentials such as diaphragm compressors.
2) Shaft seal design such as carbon rings, double mechanical seals or buffered seals.

3) Design options such as internal balancing, double inlet or gland eductors.

QUANTIFYING FUGITIVE EMISSION REDUCTIONS

Here are several important points to remember when calculating fugitive emission rates:

1) All components must be accounted for when estimating emission rates regardless of exemptions from monitoring requirements.

2) Taking an emission reduction for monitoring implies that all of those components will be monitored regardless of exemptions.

3) Non-accessible components and other unmonitored components must be clearly identified and separated from monitored components when calculating emission rates.

4) All components given emission reduction credits for monitoring must be capable of having reduced emissions through the monitoring program, i.e., any components represented as being monitored must have sufficient vapor pressure to allow the reduction.

5) Representations of emission reductions in a permit application will result in permit special conditions requiring monitoring for certain components based on the emission estimates.

6) Instrument monitoring of connectors is not required by any of the LDAR programs other than 28 LAER. A 30% reduction can be taken for the required weekly walk-through inspection. For quarterly instrument monitoring of connectors under the 28CNTQ LDAR program, the valve credit corresponding to the appropriate leak definition for the LDAR program may be applied instead of the 30% credit. A 75% credit may be taken for annual connector monitoring at a 500 ppm leak definition in conjunction with the 28CNTA LDAR program. The 28CNT LDAR programs are used in addition to the other 28 series LDAR programs if connector monitoring is required by special circumstances.

7) Emission calculations should include a component count for those components with a 100%

control efficiency with a footnote describing the specific method of control.

IV. INFORMATION NEEDED IN A PERMIT APPLICATION

COMPONENT COUNT, TYPE, AND SERVICE CATEGORY

The estimated fugitive emission rate is solely dependent on the number of components in service; therefore, a specific component count is necessary. The count should be separated into the component type categories, i.e., connector, valve, etc. For each specific component type, the number of components should be divided into the appropriate physical service category: gas, light liquid, heavy liquid, chlorine, etc.

With the separated source totals, an estimation of fugitive emission rates with no LDAR program in place can be made. This estimate is simply the emission factor, based on the specific compound and where it is in service, multiplied by the number of components in that service. As an example, for a valve in VOC light liquid service in a refinery, the factor used is 0.024 (lb/hr)/source; therefore, 10 of these valves will emit a total of 0.24 lb/hr. Annual emissions are determined from the short-term emission rate by assuming 8,760 hours per year of operation. The emission factors used in the calculations should be clearly footnoted to show the source of the factors.

CLAIMING EMISSION REDUCTIONS

Emission reductions claimed either though equipment specification or through any of the TCEQ leak detection and repair programs must be clearly identified. The fugitive emission calculations should show the emission factor, the appropriate reduction credit from Attachment III, and the final emission rate for each component type and, if applicable, from each different process stream. Refer to Attachment IV for a sample calculation.

SPECIATED EMISSIONS BY CHEMICAL

A speciation, or breakdown of the different compounds found in a process line, is necessary if the chemical composition is not 100% pure. The speciation is necessary to determine the off-property impact for each different chemical emitted from a fugitive source.
For example, if a line is 80% toluene and 20% ethylene, the emission rate would need to reflect the

estimated quantity of emissions for each compound. Simply multiplying the emission rate by the weight percent of each compound yields the specific emission rate for that compound. If the weight percent of a particular compound varies from one process stream to another, then the fugitive emission rate for each area should be calculated separately, multiplied by the appropriate weight percent, and then totaled. The permit applicant may also group different streams together and determine the maximum percentage of each compound for that group. When using this method, the percentages may total over 100 percent. The total emission rate of each individual chemical should be shown on the Table 1(a), Emission Source Table, submitted with the permit application.

MODIFICATIONS

When submitting a permit application that involves changes to existing permitted equipment, show the existing component counts and emissions rate, the proposed component counts and emissions rate, and the overall changes. The new and increased emissions will be evaluated as part of the permit review process to determine if any off-property impact concerns exist.

V. BEST AVAILABLE CONTROL TECHNOLOGY GUIDELINES

An integral part of the permitting process is the determination of Best Available Control Technology (BACT) for all new and modified sources. Since fugitive emissions are estimated as a whole for a process unit or area, the addition of new piping components will trigger a BACT review for all of the piping components. Table II provides guidelines for determining BACT for process fugitive emissions when submitting a permit application.

Table II

Best Available Control Technology Guidelines for Fugitive Emissions

Uncontrolled Annual Fugitive Emission Rate	**Best Available Control Technology (BACT)**
< 10 tpy	May Not Require Monitoring †
10 ≤ x < 25 tpy	28M Program †
≥ 25 tpy	28VHP Program

† If subject to TCEQ 30 TAC 115.352, 28RCT applies

It is important to note that the uncontrolled annual emission rate triggers and corresponding LDAR programs given in Table II are guidelines only; a case-by-case review will be performed for all permit applications. Separate applicability determinations must also be made for 30 TAC Chapter 115 (TCEQ Regulation V), 40 CFR Part 60, 40 CFR Part 61 or MACT affected sources. It is important to note that a more stringent program may be requested if it is currently in use at other units at the same plant site. For example, a new unit at a large chemical plant would be expected to implement at least the 28M leak detection and repair program even if the uncontrolled fugitive emissions from the new unit are calculated to be less than 10 tons annually.

In addition to the instrument monitoring requirements, certain components have additional requirements to meet BACT. Open-ended lines are required to be equipped with a cap, plug, blind flange or second valve as BACT. New relief valves are required to vent to a control device as BACT for any potential releases and as a side result any fugitive emissions are also controlled. If instrument monitoring is chosen for existing relief valves, monitoring must be performed quarterly regardless of the accessibility of the relief valves. Additional information on BACT for existing relief valves is contained in “Permit Review of Non-traditional Sources of Air Contaminants” by Alan Pegues, PhD., P.E., 1993.

OFF-PROPERTY IMPACTS REVIEW

The control technology determination is separate from the off-property impacts assessment performed during the permit review process. A more stringent LDAR program (up to 28MID) may be required if the TCEQ Toxicology and Risk Assessment Section determines that the predicted off-property impact of fugitive emissions is unacceptable. If impacts problems still exist with the 28MID LDAR program implemented, the following additional steps may be required:

1) Monitoring of connectors using an organic vapor analyzer as opposed to weekly physical inspections
2) Equipment specifications for leakless operation (See Section III)
3) Applicant developed proposal

SPECIAL CONDITIONS - 28M

Piping, Valves, Connectors, Pumps, and Compressors in Volatile Organic Compounds (VOC) Service - 28M

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.5 psia at 100°F or at maximum process operating temperature if less than 100°F or (2) to piping and valves two inches nominal size and smaller or (3) where the operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

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

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined in TCEQ 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring period after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

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

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations § 60.485(a) - (b) (40 CFR 60.485[a] - [b]).

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

Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves, connectors, compressor seals, and pump seals found to be emitting VOC in excess of 10,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Every reasonable effort shall be made to repair a leaking component as specified in this paragraph within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TCEQ Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

I. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

J. Fugitive emission monitoring required by an applicable New Source Performance Standard (NSPS), 40 CFR Part 60, or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS), 40 CFR Part 61, may be used in lieu of Items F through I of this condition.

Compliance with the requirements of this condition does not assure compliance with requirements of NSPS or NESHAPS and does not constitute approval of alternate standards for these regulations.

SPECIAL CONDITIONS - 28RCT

Piping, Valves, Connectors, Pumps, and Compressors in Volatile Organic Compounds (VOC) Service - 28RCT

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

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure equal to or less than 0.044 psia at 68°F or (2) *** REMOVE IF SUBJECT TO REG. V* to piping and valves two inches nominal size and smaller** or (3) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

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

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by TCEQ 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

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

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations Part 60.485(a) - (b).

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

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

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump and compressor seals found to be emitting VOC in excess of 10,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired.

I. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TCEQ Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

J. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

K. Fugitive emission monitoring required by 30 TAC Chapter 115 may be used in lieu of Items F through I of this condition.

Compliance with the requirements of this condition does not assure compliance with requirements of an applicable New Source Performance Standard or an applicable National Emission Standard for Hazardous Air Pollutants and does not constitute approval of alternative standards for these regulations.

SPECIAL CONDITIONS - 28VHP

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

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

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 psia at 68°F or (2) *** REMOVE IF SUBJECT TO REG. V* to piping and valves two inches nominal size and smaller** or (3) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

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

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by TCEQ 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

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

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations Part 60.485(a) - (b).

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

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

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

I. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TCEQ Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

J. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

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

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

Piping, Valves, Connectors, Pumps, and Compressors in (insert compound) Service - Intensive Directed Maintenance - 28MID

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

A. These conditions shall not apply (1) where the concentration in the stream is less than XX percent by weight or (2) where the volatile organic compounds (VOC) has an aggregate partial pressure or vapor pressure of less than 0.044 psia at 68°F or (3) *** REMOVE IF SUBJECT TO REG. V.* to piping and valves two inches nominal size and smaller** or (4) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

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

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by TCEQ 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

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

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations § 60.485(a) - (b).

A directed maintenance program shall consist of the repair and maintenance of components assisted simultaneously by the use of an approved gas analyzer such that a minimum concentration of leaking VOC is obtained for each component being maintained. Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. All new and replacement pumps and compressors shall be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. These seal systems need not be monitored and may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

All other pump and compressor seals emitting VOC shall be monitored with an approved gas analyzer at least quarterly.

H. Damaged or leaking valves, connectors, compressor seals, and pump seals found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TCEQ Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

I. In lieu of the monitoring frequency specified in paragraph F, valves in gas and light liquid service may be monitored on a semiannual basis if the percent of valves leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Valves in gas and light liquid service may be monitored on an annual basis if the percent of valves leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of valves leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

J. The percent of valves leaking used in paragraph I shall be determined using the following formula:

$$(Vl + Vs) \times 100/Vt = Vp$$

Where:

Vl = the number of valves found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

Vs = the number of valves for which repair has been delayed and are listed on the facility shutdown log.

Vt = the total number of valves in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor valves.

Vp = the percentage of leaking valves for the monitoring period.

K. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

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

SPECIAL CONDITIONS - 28LAER

Piping, Valves, Connectors, Pumps, Agitators, and Compressors in Volatile Organic Compounds (VOC) Service - Intensive Directed Maintenance - 28LAER

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

A. With the exception of paragraph N, these conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 psia at 68°F or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

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

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by TCEQ 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through. In addition, all connectors shall be monitored by leak-checking for fugitive emissions at least annually using an approved gas analyzer with a directed maintenance program.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

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

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations § 60.485(a) - (b).

A directed maintenance program shall consist of the repair and maintenance of components assisted simultaneously by the use of an approved gas analyzer such that a minimum concentration of leaking VOC is obtained for each component being maintained. Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. All new and replacement pumps and compressors shall be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. These seal systems need not be monitored and may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

All other pump, compressor, and agitator seals emitting VOC shall be monitored with an approved gas analyzer at least quarterly.

H. Damaged or leaking valves, connectors, agitator seals, compressor seals, and pump seals found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. At the discretion of the TCEQ Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

I. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

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

K. In lieu of the monitoring frequency specified in paragraph F, valves in gas and light liquid service may be monitored on a semiannual basis if the percent of valves leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Valves in gas and light liquid service may be monitored on an annual basis if the percent of valves leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of valves leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

L. The percent of valves leaking used in paragraph K shall be determined using the following formula:

$$(V_l + V_s) \times 100/V_t = V_p$$

Where:

V_l = the number of valves found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

V_s = the number of valves for which repair has been delayed and are listed on the facility shutdown log.

V_t = the total number of valves in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor valves.

V_p = the percentage of leaking valves for the monitoring period.

M. Alternative connector monitoring frequency schedules (“skip options”) of 40 Code of Federal Regulations Part 63, Subpart H, National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks, may be used in lieu of the annual connector instrument monitoring required by paragraph E of this permit condition.

N. Any component found to be leaking by physical inspection (i.e., sight, sound, or smell) shall be repaired or monitored with an approved gas analyzer within 15 days to determine whether the component is leaking in excess of 500 ppmv of VOC. If the component is found to be leaking in excess of 500 ppmv of VOC, it shall be subject to the repair and replacement requirements contained in this special condition.

AUDIO, VISUAL AND OLFACTORY (AVO) INSPECTION

Piping, Valves, Pumps, and Compressors in (insert compound) Service

A. Audio, olfactory, and visual checks for (insert compound) leaks within the operating area shall be made every four hours.

B. Immediately, but no later than one hour upon detection of a leak, plant personnel shall take the following actions:

(1) Isolate the leak.
(2) Commence repair or replacement of the leaking component.
(3) Use a leak collection/containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.

Date and time of each inspection shall be noted in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the Texas Commission on Environmental Quality (TCEQ) upon request.

PETROLEUM MARKETING TERMINAL AUDIO, VISUAL, AND OLFACTORY (AVO) INSPECTION

<u>Piping, Valves, Pumps, and Compressors in Petroleum Service</u>

A. Audio, olfactory, and visual checks for petroleum product leaks within the operating area shall be made monthly.

B. Every reasonable effort shall be made to repair or replace a leaking component within 15 days after a leak is found. If the repair or replacement of a leaking component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired or replaced until a scheduled shutdown shall be identified in a list to be made available to representatives of the Texas Commission on Environmental Quality (TCEQ) upon request.

Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the TCEQ upon request.

28 CNTA

In addition to the weekly physical inspection required by Item E of Special Condition XX, all connectors in gas\vapor and light liquid service shall be monitored annually with an approved gas analyzer in accordance with Items F thru J of Special Condition XX. Alternative monitoring frequency schedules ("skip options") of 40 Code of Federal Regulations Part 63, Subpart H, National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks, may be used in lieu of the monitoring frequency required by this permit condition. Compliance with this condition does not assure compliance with requirements of applicable state or federal regulation and does not constitute approval of alternative standards for these regulations.

28CNTQ

A. In addition to the weekly physical inspection required by Item E of Special Condition XX, all accessible connectors in gas\vapor and light liquid service shall be monitored quarterly with an approved gas analyzer in accordance with Items F thru J of Special Condition XX.

B. In lieu of the monitoring frequency specified in paragraph A, connectors may be monitored on a semiannual basis if the percent of connectors leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Connectors may be monitored on an annual basis if the percent of connectors leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of connectors leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

Uncontrolled SOCMI Fugitive Emission Factors

Equipment/Service	**SOCMI Average** [1]	**SOCMI Without C_2** [2]	**SOCMI With C_2** [2]	**SOCMI Non-Leaker** [3]
Valves				
Gas/Vapor	0.0132	0.0089	0.0258	0.00029
Light Liquid	0.0089	0.0035	0.0459	0.00036
Heavy Liquid	0.0005	0.0007	0.0005	0.0005
Pumps				
Light Liquid	0.0439	0.0386	0.144	0.0041
Heavy Liquid	0.019	0.0161	0.0046	0.0046
Flanges/Connectors				
Gas/Vapor	0.0039	0.0029	0.0053	0.00018
Light Liquid	0.0005	0.0005	0.0052	0.00018
Heavy Liquid	0.00007	0.00007	0.00007	0.00018
Compressors	0.5027	0.5027	0.5027	0.1971
Relief Valve (Gas/Vapor)	0.2293	0.2293	0.2293	0.0986
Open-ended Lines [4]	0.0038	0.004	0.0075	0.0033
Sampling Connections [5]	0.033	0.033	0.033	0.033

Notes: All factors are in units of (lb/hr)/component.

1. Factors are taken from EPA Document, EPA-453/R-95-017, November 1995, Page 2-12.
2. Factors are TCEQ derived.
3. Control credit is included in the factor; no additional control credit can be applied to these factors. AVO walk-through inspection required.
4. The 28 Series quarterly LDAR programs require open-ended lines to equipped with a cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.
5. Use the SOCMI Sampling Connection factor for Non-Leaker. Emission factor is in terms of Pounds per Hour per Sample Taken.

Facility/Compound Specific Fugitive Emission Factors

Equipment/ Service	Ethylene Oxide[1]	Phosgene[2]	Butadiene[3]	Petroleum Marketing Terminal[4]	Oil and Gas Production Operations[5]				Refinery[6]
					Gas	Heavy Oil <20° API	Light Oil	Water/Light Oil	
Valves					0.00992	0.0000185	0.0055	0.000216	
Gas/Vapor	0.000444	0.00000216	0.001105	0.0000287					0.059
Light Liquid	0.00055	0.00000199	0.00314	0.0000948					0.024
Heavy Liquid				0.0000948					0.00051
Pumps	0.042651	0.0000201	0.05634		0.00529	0.00113[10]	0.02866	0.000052	
Light Liquid				0.00119					0.251
Heavy Liquid				0.00119					0.046
Flanges/Connectors	0.000555	0.00000011	0.000307		0.00086	0.00000086	0.000243	0.000006	0.00055
Gas/Vapor				0.000092604					
Light Liquid				0.00001762					
Heavy Liquid				0.0000176					
Compressors	0.000767		0.000004		0.0194	0.0000683	0.0165	0.0309	1.399
Relief Valve	0.000165	0.0000162	0.02996		0.0194	0.0000683	0.0165	0.0309	0.35
Open-ended Lines[7]	0.001078	0.00000007	0.00012		0.00441	0.000309	0.00309	0.00055	0.0051
Sampling	0.000088		0.00012						0.033
Connectors					0.00044	0.0000165	0.000463	0.000243	
Other[9]					0.0194	0.0000683	0.0165	0.0309	
Gas/Vapor				0.000265					
Light/Heavy Liquid				0.000287					
Process Drains					0.0194	0.0000683	0.0165	0.0309	0.07

Table Notes: All factors are in units of (lb/hr)/component.

1. Monitoring must occur at a leak definition of 500 ppmv. No additional control credit can be applied to these factors. Emission factors are from EOIC Fugitive Emission Study, Summer 1988.

2. Monitoring must occur at a leak definition of 50 ppmv. No additional control credit can be applied to these factors. Emission factors are from Phosgene Panel Study, Summer 1988.

3. Monitoring must occur at a leak definition of 100 ppmv. No additional control credit can be applied to these factors. Emission factors are from Randall, J. L., et al., Radian Corporation. Fugitive Emissions from the 1,3-butadiene Production Industry: A Field Study. Final Report. Prepared for the 1,3-Butadiene Panel of the Chemical Manufacturers Association. April 1989.

4. Control credit is included in the factor; no additional control credit can be applied to these factors. Monthly AVO inspection required.

5. Factors give the total organic compound emission rate. Multiply by the weight percent of non-methane, non-ethane organics to get the VOC emission rate.

6. Factors are taken from EPA Document EPA-453/R-95-017, November 1995, Page 2-13.

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

8. Emission factor for Sampling Connections is in terms of pounds per hour per sample taken.

9. For Petroleum Marketing Terminals”Other” includes any component excluding fittings, pumps, and valves. For Oil and Gas Production Operations, “Other” includes diaphragms, dump arms, hatches, instruments, meters, polished rods, and vents.

10. No Heavy Oil - Pump factor was derived during the API study. The factor is the SOCMI without C_2 Heavy Liquid - Pump factor with a 93% reduction credit for the physical inspection.

Control Efficiencies for TCEQ Leak Detection and Repair Programs

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

Notes:

1. Audio, visual, and olfactory walk-through inspections are applicable for inorganic/odorous and low vapor pressure compounds referenced in Section II.

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

3. No credit may be taken if the concentration at saturation is below the leak definition of the monitoring program (i.e. (0.044 psia/14.7 psia) x 10^6 = 2,993 ppmv versus leak definition = 10,000 ppmv)

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

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

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

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

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

Sample Fugitive Emission Rate Calculations
Chemical Plant Implementing the 28VHP LDAR Program

Component Name	Stream Type	Number of Components	SOCMI w/o C_2 Emission Factors	LDAR Program	Control Efficiency	Controlled Emission Rates	
						Lbs/Hour	**Tons/Year**
Valves	Gas/Vapor	1,019	0.0089	28VHP	97%	0.27	1.19
Valves	Light Liquid	2,263	0.0035	28VHP	97%	0.24	1.04
Pumps	Light Liquid	14	0.0386	28VHP	85%	0.08	0.36
Connectors	Gas/Vapor	1,435	0.0029	28VHP	97% *	0.12	0.55
Connectors	Light Liquid	3,056	0.0005	28VHP	97% *	0.05	0.20
Compressors	Gas/Vapor	1	0.5027	28VHP	85%	0.08	0.33
Relief Valves	Gas/Vapor	12	0.2293	28VHP	100% †	0.00	0.00
Open-Ended Lines	Gas/Vapor	3	0.0040	28VHP	100% ††	0.00	0.00
Total Fugitive Emission Rates						**0.84**	**3.67**

* Flanges monitored at 500 ppmv; therefore, the valve control credit is applied.

† Relief valves routed to a flare; therefore, 100% control credit is applied.

†† The 28 Series LDAR Programs require open-ended lines to equipped with a cap, blind flange, plug, or a second valve for 100% control credit. The connector count is increased by the number of open-ended lines to account for the credit.

Fugitive Emission Speciation for Sample Calculations

Chemical Name	Weight Percent in Stream	Controlled Fugitive	
		Lbs/Hour	Tons/Year
Propane	4%	0.03	0.15
Benzene	7%	0.06	0.26
Toluene	62%	0.52	2.28
Xylene	8%	0.07	0.29
Ethylbenzene	17%	0.14	0.62
Hydrogen Sulfide *	2%	0.02	0.07
Total VOC	**98%**	**0.82**	**3.60**
Hydrogen Sulfide *	**2%**	**0.02**	**0.07**

* Calculation method assumes that the maximum off-property impact will not exceed ESL or Regulation II limits for H_2S. See Section II, Odorous/Inorganic Compounds, and Section III, Audio/Visual/Olfactory Walk-Through Inspection, for additional information.