

US EPA ARCHIVE DOCUMENT

**APPLICATION FOR A
U.S. ENVIRONMENTAL PROTECTION AGENCY
GREENHOUSE GAS AIR QUALITY PERMIT
FOR A NEW CONDENSATE SPLITTER FACILITY**

Prepared for

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LIST OF ACRONYMS

BACT	Best Available Control Technology
bbbl	barrel
BPD	barrels per day
CCI	CCI Corpus Christi LLC
CCS	Carbon Dioxide Capture and Sequestration
CF	Condensate Fractionator
CFR	Code of Federal Regulations
CH ₄	methane
CO ₂	carbon dioxide
CO ₂ e	carbon dioxide equivalent
CSF	Condensate Splitter Facility
DOE	U.S. Department of Energy
DRE	destruction removal efficiency
EPA	United States Environment Protection Agency
EPN	Emission Point Number
GHG	greenhouse gas
GWP	global warming potential
HFCs	hydrofluorocarbons
IR	infrared
LDAR	leak detection and repair
MMBtu/hr	10 ⁶ British Thermal Units per hour
MVCU	Marine Vapor Control Units
MMgal/yr	10 ⁶ gallons per year
MSS	Maintenance, Startup, and Shutdown
N ₂ O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
PFCs	perfluorocarbons
PSD	Prevention of Significant Deterioration
RBLC	Reasonably Available Control Technology / Best Available Control Technology Lower Achievable Emission Rate Clearinghouse
SOCMI	Synthetic Organic Chemical Manufacturing Industry

tpy short ton (i.e., 2,000 lb) per year

VCU vapor combustion unit

VFR vertical fixed roof

VOCs volatile organic compounds

VRU vapor recovery units

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1. INTRODUCTION

CCI Corpus Christi LLC (CCI) proposes to construct a new Condensate Splitter Facility (CSF) to be located near Corpus Christi, Texas in Nueces County. The proposed CSF will be comprised of two fractionation trains, each capable of processing 50,000 barrels (bbl) per day (BPD) for a total processing capability of 100,000 BPD of condensate blends.

The product slate will include Y-grade, naphtha, jet fuel, diesel, and gas oil/residual. A Jet Fuel Treating Unit will treat rundown jet fuel to meet Jet A-1 and JP-54 grade kerosene specifications.

With this application, CCI requests a Greenhouse Gas (GHG) air quality permit authorization to construct the proposed new CSF in Corpus Christi, Texas. This initial GHG permit application is provided consistent with the requirements in Title 40 of the Code of Federal Regulations, Part 52 (40 CFR 52) and specifically with §52.21, “Prevention of Significant Deterioration (PSD)” requirements.

An area map showing the location of the proposed new CSF is included in this section as **Figure 1-1**. A plot plan for the proposed new CSF is included as **Figure 1-2**.

1.1 PROJECT OVERVIEW

The proposed new CSF will be constructed in Nueces County, near Corpus Christi, Texas and will process 100,000 BPD of hydrocarbon condensate material using conventional distillation technologies. The proposed CSF will be comprised of two identical fractionation trains, each capable of processing 50,000 BPD condensate.

New process equipment associated with this project includes process heaters, auxiliary boiler, flare, vapor combustion unit, emergency generator, firewater pumps, cooling tower, storage tanks, and associated piping and other equipment components.

1.2 PSD APPLICABILITY EVALUATIONS

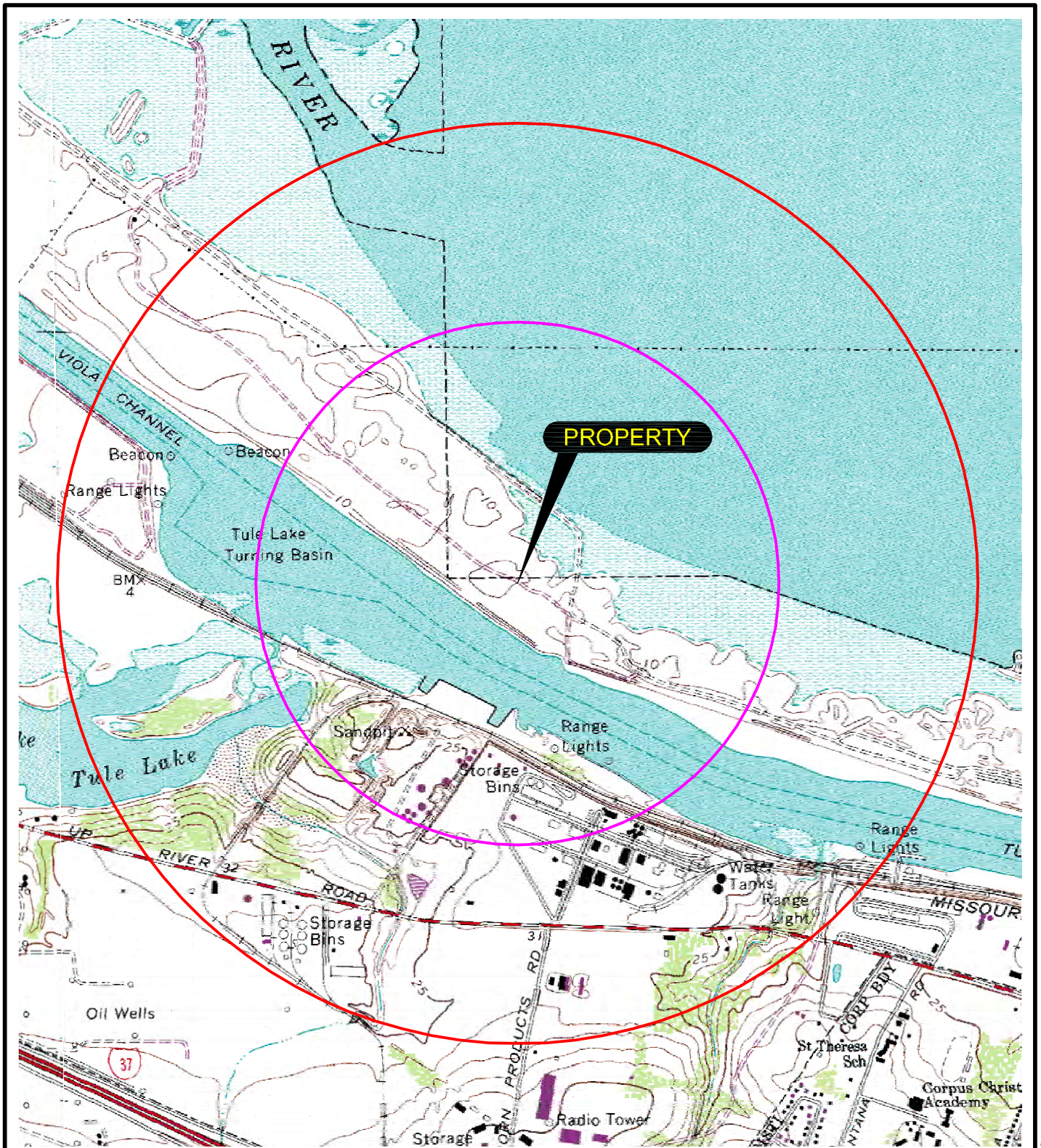
This application is provided to the EPA to request PSD permit authorization as required under 40 CFR §52.21 for constructing a new major stationary source of regulated GHG air pollutants.

Construction of the new CSF facility will occur after 1 July 2011, and the associated GHG potential to emit for the entire facility is greater than 100,000 tons per year (tpy) of carbon dioxide equivalent (CO₂e). Therefore, a PSD permit appears to be required for GHG emissions as specified in §52.21(b)(49).

PSD applicability tables are included in **Appendix C** to document the determination that the proposed CSF construction is subject to PSD permitting requirements for GHG emissions. Project-related GHG potential to emit calculations are included in **Appendix D**. Because this is a proposed new stationary source, and there are no contemporaneous projects to evaluate, PSD netting tables are not included in **Appendix C**. **Table D-1** (in **Appendix D**) summarizes the project-related GHG potential emissions, and **Appendix C** provides additional PSD emission summaries and PSD applicability analysis information.

Based on §52.21 and related EPA guidance documents, CCI understands the following with regard to other evaluations required for PSD permitting of regulated GHG pollutants:

- EPA has not established NAAQS specific to regulated GHG pollutants.
- Air dispersion modeling of the regulated GHG pollutants is not required under §52.21(k) at this time.
- Preconstruction air quality monitoring of regulated GHG pollutants is not required under §52.21(m)(1)(ii) at this time.
- Additional impacts analysis of regulated GHG pollutants on designated Class I areas is not required under §52.21(o) at this time.



LEGEND

- 3,000-FOOT RADIUS
- 1-MILE

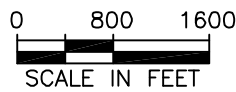
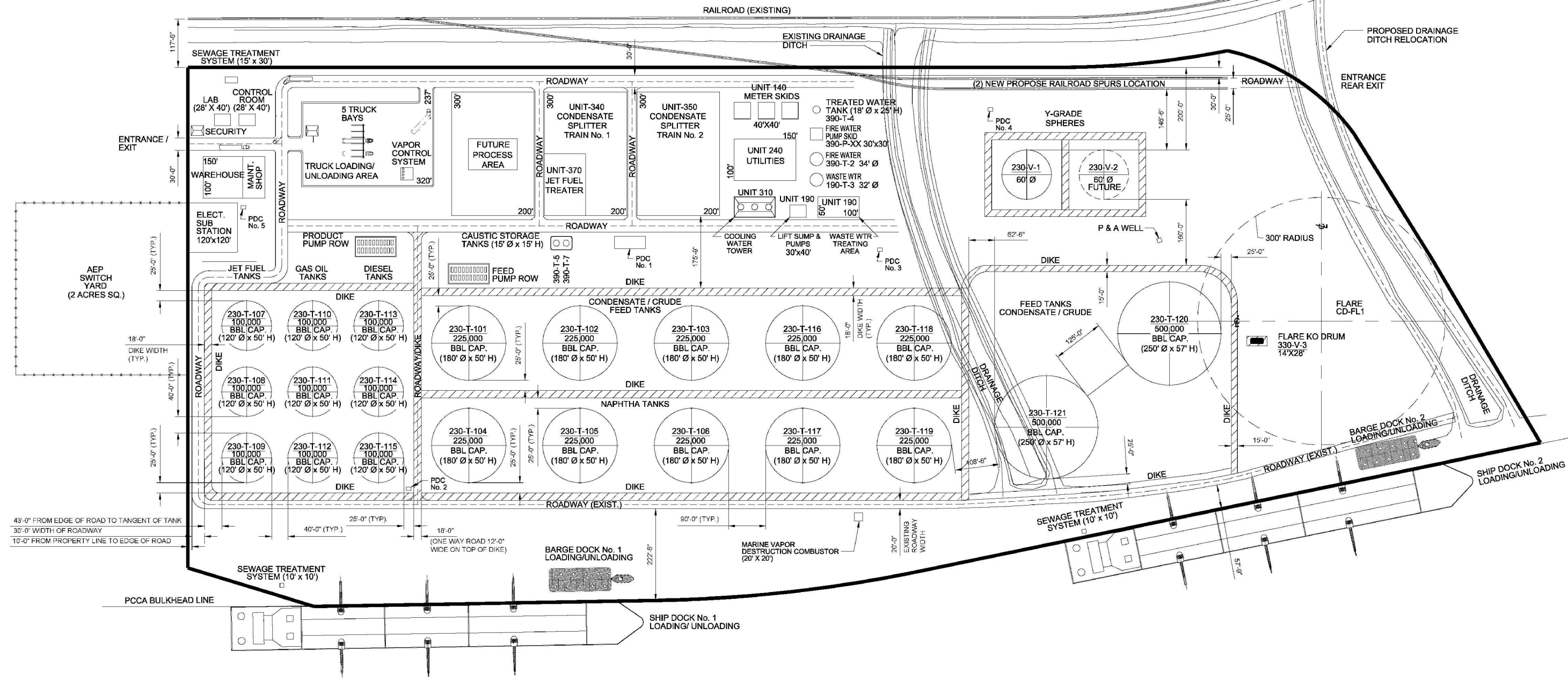


FIGURE 1-1

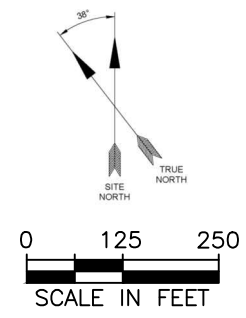
AREA MAP

**CCI CORPUS CHRISTI LLC
CORPUS CHRISTI, NUECES COUNTY, TX**

DATE	PROJECT NO.	SCALE
OCT 2013	13844.058.001	AS SHOWN



LEGEND	
	RAILROAD
	ROADWAY
	ROADWAY/DIKE
	DIKE
	POWER DISTRIBUTION CENTER (PDC No. XX)



WESTON SOLUTIONS

FIGURE 1-2
PLOT PLAN

CCI CORPUS CHRISTI LLC
CORPUS CHRISTI, NUECES COUNTY, TX

DATE OCT 2013	PROJECT NO. 13844.058.001	SCALE AS SHOWN
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2. PROCESS DESCRIPTION

The proposed new CSF will be composed of two identical fractionation systems capable of processing 50,000 BPD of condensate each for a total processing capability of 100,000 BPD. The product slate will include Y-grade, combined naphtha, jet fuel, diesel, and gas oil/ residual bottoms.

A simplified process flow diagram for the CSF is provided as **Figure 2-1**.

A wide range of condensate feedstock will be stored in storage tanks that will be equipped with floating roofs. The condensate feedstock will be preheated using a series of heat exchangers using excess heat recovered from hot splitter overhead, naphtha, jet fuel, diesel, and splitter bottoms stream. A portion of the hot stripper bottoms stream will provide heat for the Jet Fuel Stripper reboiler, Diesel Product Stripper reboilers, and the Naphtha reboiler. The preheated condensate feed will pass through a condensate PreFlash drum where a portion of the condensate feed rate will be flashed off as vapor. The flashed vapor will be routed to the fractionation column below the jet fuel draw section. Liquid from the PreFlash drum will be pumped to a charge heater and then routed to the fractionation column for processing.

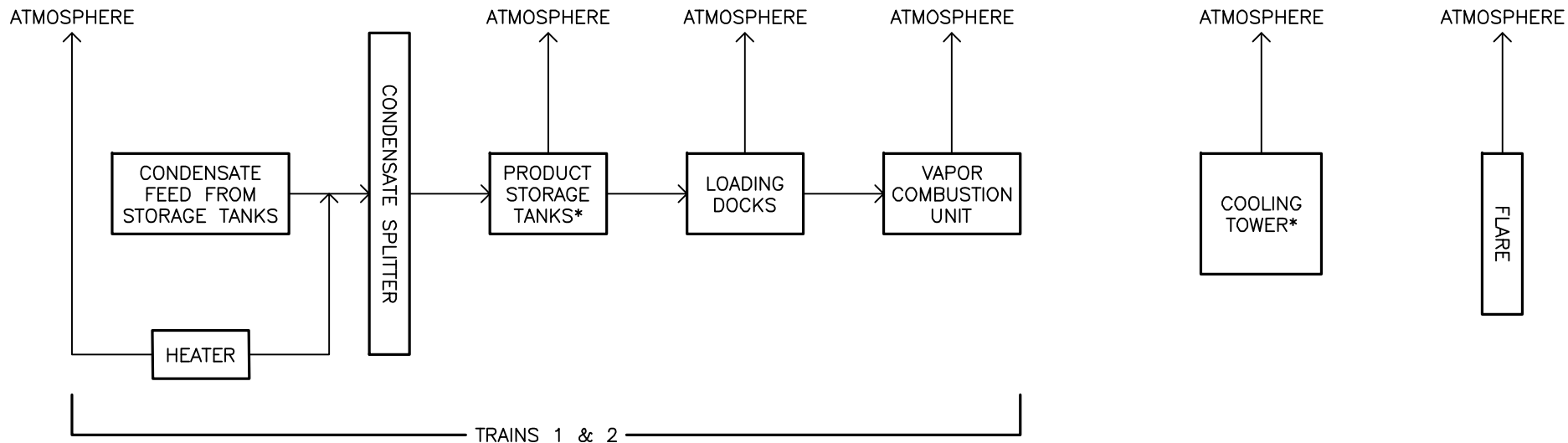
Three product strippers will remove light material from each product stream to meet flash or vapor pressure specifications. A Naphtha Stripper will remove lighter components from the heavy naphtha, allowing more light naphtha for blending purposes. There will also be a Jet Fuel Stripper and a Diesel Product Stripper that operate in a similar manner to the Naphtha Stripper.

2.1 SUPPORTING OPERATIONS

Both fractionation trains at the CSF will be supported by a common flare system, vapor combustor unit, fuel gas system, and jet fuel treating facility. Other common utilities include electrical power, plant air, instrument air, cooling water, process water, firewater, natural gas, and nitrogen.

2.2 PLANNED MAINTENANCE, STARTUP, AND SHUTDOWN ACTIVITIES

Planned MSS activities will occur in order to ensure the operation of the CSF. Such activities will require shutdown of the processes and subsequent start-up to return to normal operations. A common flare at the site will control emissions from planned MSS activities, including combustion gases from equipment clearing. Other MSS activities will include maintenance of the storage tanks, including tank degassing, cleaning, and refilling. Emissions from tank degassing will be routed to a temporary control device (portable thermal oxidizer) and other MSS emissions will be routed to the flare for control.



NOTE:

* INDICATES SOURCE DOES NOT CONTRIBUTE TO GREENHOUSE GAS EMISSIONS.



FIGURE 2-1
PROCESS FLOW DIAGRAMS

CCI CORPUS CHRISTI LLC
CORPUS CHRISTI, NUECES COUNTY, TX

DATE	PROJECT NO.	SCALE
OCT 2013	13844.058.001	AS SHOWN

3. EMISSION SOURCES AND CALCULATION METHODOLOGIES

The quantity of GHG emissions is the sum of six individual compounds emitted from an emission source on both a mass basis and a carbon dioxide equivalent (CO₂e) basis. The CO₂e emission rates are based on the mass emission rates of each applicable GHG compound multiplied by the global warming potential (GWP) of the corresponding compound as per 40 CFR Part 98, Subpart A, Table A-1. The GHGs emitted from the proposed facilities include carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O). CCI does not expect emissions of hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), or sulfur hexafluoride (SF₆) from the proposed facilities.

This section describes the GHG emission calculation methods applied to each source type included in this application. A summary of GHG emissions may be found in **Table D-1** of **Appendix D**.

3.1 HEATERS

The new CSF will utilize two natural gas fired heaters designated as EPNs H-1 and H-2. GHG emissions from the two combustion units were calculated using the proposed maximum hourly and average annual firing rates and GHG emission factors for natural gas fuel combustion from 40 CFR Part 98, Subpart C, Tables C-1 and C-2. Detailed GHG emission calculations are provided in **Table D-2** in **Appendix D**.

3.2 AUXILIARY BOILER

The new CSF will utilize one natural gas fired boiler designated as EPN BL-1. GHG emissions from the heater were calculated using the proposed maximum hourly and average annual firing rates and GHG emission factors for natural gas fuel combustion from 40 CFR Part 98, Subpart C, Tables C-1 and C-2. Detailed GHG emission calculations are provided in **Table D-2** in **Appendix D**.

3.3 FLARE

A process flare (EPN FL-1) will be utilized to safely manage combustible gases generated during planned MSS activities or upset events. Upset events are not being proposed for permit authorization. During normal operations, only natural gas as pilot fuel will be burned in the plant flare. GHG emissions from the flare during normal operations will include unburned CH₄ and small amounts of CO₂ and N₂O from the combustion process of pilot fuel. GHG emissions for normal flare operations were calculated using the estimated maximum hourly and average annual pilot gas flow rates and the appropriate emission factors. The CO₂ emissions were based on the factor from U.S. EPA's AP-42 Table 1.4-2 (July 1998). The CH₄ and N₂O emission factors were based on 40 CFR Part 98 Subpart C, Table C-2. Detailed GHG emission calculations from the plant flare are provided in Table D-3 in **Appendix D**.

3.4 EMERGENCY GENERATOR AND FIREWATER PUMP ENGINES

A diesel fired emergency power generator (EPN EMGEN) will be utilized to maintain critical electrical services in the event of power outage to minimize upset flare loads. In addition, there will be two diesel fired firewater pump engines (EPNs FW-1 and FW-2). The potential emissions from these engines are based on the proposed hourly and annual firing rates and GHG emission factors for distillate fuel No. 2 combustion found in 40 CFR Part 98, Subpart C, Table C-1 and Table C-2. Detailed GHG emission calculations for the emergency generator and firewater pump engines are provided in **Table D-5** in **Appendix D**.

3.5 MARINE VAPOR CONTROL UNITS

A Marine Vapor Control Unit (EPN MVCU) will control vapors associated with marine loading activities. During product loading, natural gas will be used as fuel for the pilot and for enrichment gas. GHG emissions generated from the combustion of collected loading vapors were calculated using the loading vapor loss equations described in U.S. EPA's AP-42, Section 5.2 (June 2008), CO₂ emission factors derived from U.S. EPA's AP-42 Table 1.4-2 (September 1998) and CH₄/N₂O emission factors from 40 CFR, Part 98, Subpart C, Table C-1 and C-2. Detailed GHG emission calculations from the MVCU are provided in **Table D-6** located in **Appendix D**.

3.6 FUGITIVE COMPONENTS

Fugitive emissions of methane were calculated based on the calculated fugitive emission rate and a conservative estimate of methane content. The calculated fugitive emission rate was calculated using the number of fugitive components by service and Synthetic Organic Chemical Manufacturing Industry (SOCMI) “without ethylene” emission factors from TCEQ’s *Technical Guidance Package for Equipment Leak Fugitives* (November, 2000). The monitoring credits were applied based on TCEQ’s 28VHP leak detection and repair (LDAR) program. In the absence of detailed stream speciation, the CH₄ concentration is conservatively assumed to be 20%. Detailed GHG emission calculations for fugitive components are provided in **Table D-7** in **Appendix D**.

3.7 PLANNED MAINTENANCE, STARTUP, AND SHUTDOWN EMISSIONS

The following MSS activities may result in GHG emissions:

- Start-up and shutdown of heaters;
- MSS Vapor Control;
- Storage tanks;
- Clearing of process vessels and equipment;
- Fugitive component repair and replacement;
- Vacuum trucks; and
- Frac tanks.

3.7.1 Start-up and Shutdown of Heaters

The proposed natural gas fired heaters are expected to operate within the GHG emission rates discussed in **Section 3.1** during start-up and shutdown periods, and no additional GHG emissions are included in this application for heater MSS.

3.7.2 MSS Vapor Control

GHG emissions will be generated from the control of vapors associated with various MSS activities. The new CSF will utilize the process flare discussed in **Section 3.2** to control VOC emissions associated with MSS activities. Flaring will occur during planned plant turnarounds and equipment clearing for maintenance purposes. Annual GHG flare emissions were

conservatively calculated based on the number of planned plant shutdowns in a 12-month period and the total equipment volume capacity at the CSF. Detailed GHG emission calculations from MSS is provided in Table **D-4** located in **Appendix D**.

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4. BEST AVAILABLE CONTROL TECHNOLOGY

New sources subject to PSD regulations require that Best Available Control Technology (BACT) be applied to each facility with the potential to emit an air pollutant for which a significant net emissions increase will occur. GHG is the only pollutant addressed in this application and will be produced by individual sources of CO₂, CH₄, and N₂O and addressed as CO₂e emissions that include combustion units and potential fugitive component leaks.

The EPA recommends the five-step “top-down” BACT analysis methodology for GHG sources as outlined in *PSD and Title V Permitting Guidance for Greenhouse Gases* (EPA-457/B-11-001, March 2011). This methodology calls for identification of all available control technologies for a given pollutant and ranks these technologies in descending order of control effectiveness to determine the most stringent control available for a similar or identical emission source. This analysis is based on a case-by-case basis with consideration to technical practicability and economic reasonableness. The EPA has outlined this process in the following five steps:

Step 1: Identify all available control technologies.

Step 2: Eliminate technically infeasible options.

Step 3: Rank remaining control technologies based on control effectiveness.

Step 4: Evaluate control technologies for cost-effectiveness, energy and environmental impacts.

Step 5: Select the BACT.

The “top-down” approach as described above has been followed in this BACT analysis for the following plant-wide GHG emitting sources:

- Process Heaters;
- Boiler;
- Flare;
- Marine Vapor Control unit;
- Process Fugitives;
- Emergency Generators and Firewater Pump Engines.

The following resources were utilized to perform the BACT analysis.

- EPA's Reasonably Available Control Technology / Best Available Control Technology / Lower Achievable Emission Rate Clearinghouse (RBLC) database;
- Approved GHG permit applications for similar source types in the state of Texas;
- EPA's *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry*, November 2010 (referred to herein as GHG BACT for Refineries);
- Department of Energy's *Report of the Interagency Task Force on Carbon Capture and Storage*, October 2010; and
- Ernest Orlando Lawrence Berkeley National Laboratory's *Energy Efficiency Improvement and Cost Savings for the Petrochemical Industry*, July 2008.

4.1 PLANT-WIDE SOURCES

Step 1 – Identification of Potential Control Technologies

Carbon Dioxide Capture and Sequestration (CCS): CCS technologies involve the separation, collection, and compression of CO₂ gas from point source emissions, transportation of the compressed CO₂ gas to an on-site or off-site storage facility, and sequestering of the CO₂ in a viable storage facility.

The proposed CSF will emit CO₂ from a number of different processes and emission points throughout the facility. The consideration of the CCS at this site would likely be limited to the larger CO₂-emitting stacks, such as the process heaters and the auxiliary boiler. The capture of the CO₂ gas emissions would require separation of the CO₂ gas from the combined combustion exhaust flows using a CO₂ separation process.

The proposed facility will not have on-site CO₂ storage. Therefore, any CO₂ captured and compressed would need to be transported off-site via a third party CO₂ pipeline system. The United States already presently has more than 3,000 miles of CO₂ pipelines used to transport CO₂ for Enhanced Oil Recovery (EOR).

Captured, compressed, and transported CO₂ may be stored or sequestered by means of currently available methods, including storage in geologic formations, EOR, and injection of CO₂ into an

active oil reserve, brine aquifer, un-mined coal seam, basalt rock formation, or an organic shale bed. The U.S. Department of Energy (DOE) has been supporting Regional Partnerships that are initiating large-scale tests to determine how geologic storage reservoirs and their surrounding environments respond to large amounts of injected CO₂ in a variety of geological formations and regions across the United States. Because CO₂ storage is still an emerging technology, regulations and standards have not been developed.

Step 2 – Elimination of Technically Infeasible Options

The process of CO₂ capture concentrates the CO₂ stream so it can be transported and/or stored. To date, successful CCS implementation has only involved highly concentrated CO₂ streams for practical and economic reasons.

The CO₂ must be separated from the combustion flue gas by a complex process that 1) filters out particulates, 2) cools the flue gas, and 3) compresses and separates the CO₂ (most likely via an amine absorption system). This process would require the installation of equipment that would otherwise not be used at the facility. For example, the separated CO₂ stream requires large compression equipment, capable of acidic gas handling (since CO₂ is highly corrosive), and high energy consumption to pressurize the gas for pipeline transportation. The energy demand required to operate a carbon capture system would potentially require the construction and operation of a cogeneration unit (cogen unit). A cogen unit could be associated with a significant amount of emissions of GHGs and other regulated pollutants that would require additional controls. Although a CCS system would be technically challenging, it may not be infeasible and therefore needs to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Ranking of Remaining Technologies Based on Control Effectiveness

The economic reasonableness assessment is based on a 90% capture efficiency of the following CO₂-emitting sources at the site:

- Two Charge Heaters (EPNs: H-1 and H-2);
- Auxiliary Boiler (EPN: BL-1).

These three sources contribute 96% to the total CO₂e emissions. Therefore, a CCS system for these sources would be the most effective method of controlling site-wide CO₂ emissions.

Step 4 – Evaluate Control Technologies for Cost-Effectiveness, Energy and Environmental Impacts

A search of the EPA RBLC database revealed no facilities listed as using CCS for BACT. However, though some aspects of CCS may prove it to be technically challenging, economics is the primary consideration in the BACT analysis. The cost of the CCS for the project is not considered effective for GHG control and, if required, would make the entire proposed project economically unviable. Therefore, CCS is not selected as a control option, and no further analysis will be considered in this permit application.

4.2 PROCESS HEATERS

Step 1 – Identification of Potential Control Technologies

Energy Efficiency Design Technologies

As described below, there are several available energy efficiency technologies for controlling GHG emissions from the charge heaters:

1. Efficient Burner Design: The heaters will have efficient burners designed with improved fuel mixing capabilities. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010*).
2. Increased Heat Transfer: The heaters will have state-of-the-art refractory and insulation materials to minimize heat loss and increase overall thermal efficiency. (*Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010*).
3. Air Preheat System: Combustion air is preheated prior to combustion; this reduces the required heat load for the heaters, increases thermal efficiency, and reduces GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010*).
4. Heat Recovery System: The flue gas from the heaters is routed through a heat recovery system that reduces the exit flue gas temperature and increases the thermal efficiency of the combustion source. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010*).
5. Product Heat Recovery: Hot product streams are cooled in heat exchangers transferring heat to the process feedstock and stripping processes reducing the heat load requirement from the heaters and GHG emissions. (*Available and Emerging*

Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010).

Best Operational Practices

As detailed below, there are several best practices that can be incorporated into the operation or design of the process heaters:

1. **Fuel Selection:** Firing natural gas as a fuel will result in lower GHG emissions as demonstrated in 40 CFR Part 98, Subpart C, “General Stationary Fuel Combustion Sources” Table C-1. Natural Gas has the lowest carbon intensity of any other available fuel.
2. **Good Combustion Practices:** Oxygen and intake air flow monitors can be used to optimize fuel/air mixing and limit excess air. The excess air should be limited to 2-3% oxygen for best combustion efficiency resulting in reduced GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010, Energy Efficiency Improvement and Cost Savings for the Petrochemical Industry, July 2008*).
3. **Periodic Maintenance:** Development of a maintenance program with documented procedures and scheduling of routine inspections and evaluations will result in increased thermal efficiency, energy savings, and reduced GHG emissions.

Step 2 – Elimination of Technically Infeasible Options

All options identified in Step 1 are considered technically feasible and therefore need to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Ranking of Remaining Technologies Based on Control Effectiveness

The control technologies outlined in Step 1 above are all effective control technologies, and the use of one technology does not preclude the use of any other control technology. Combining available control technologies and operation practices will greatly improve energy efficiency. Technically feasible control technologies and their corresponding control efficiencies are provided in **Table 4-1**.

**Table 4-1
Process Heater BACT Control Efficiencies**

Control Technology Description	Typical Overall Control Efficiency (%)	Source
Fuel Selection	40	40 CFR Part 98, Subpart C, Table C-1, “Default CO ₂ Emission Factors and High Heat Values for Various Types of Fuel”
Efficient Burner Design	N/A	GHG BACT for Refineries (Heat Recovery – Air Preheater)
Air Preheat System	10-15	GHG BACT for Refineries (Heat Recovery – Air Preheater)
Heat Recovery System	2-4	GHG BACT for Refineries (Recover Heat from Process Fuel Gas)
Increased Heat Transfer	5-10	Energy Efficiency Improvement (Section 8)
Good Combustion Practices	1-3	GHG BACT for Refineries (Combustion Air Controls-Limitations on Excess Air)
Periodic Maintenance	1-10	GHG BACT for Refineries (Improved Maintenance)

Step 4 – Evaluate Control Technologies for Cost-Effectiveness, Energy and Environmental Impacts

All of the GHG control technologies listed in **Table 4-1** above are economically reasonable and technically feasible for construction of a new facility.

Step 5 – Selection of BACT

CCI proposes that all the control options listed in **Table 4-1** as BACT for controlling GHG emissions from the two heaters.

4.3 AUXILLARY BOILER

Step 1 – Identification of Potential Control Technologies

Energy Efficiency Design Technologies

As detailed below, there are several energy efficiency technologies that can be incorporated into the design of the auxiliary boiler:

1. Air Preheat System: The combustion air is preheated prior to combustion, which reduces the required heat load and increases thermal efficiency. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010*).
2. Efficient Burner Design: New burner designs have improved fuel mixing capabilities, which increases the burner efficiency and reduce GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010*).
3. Boiler Insulation: Insulating the outside surface area of the boiler reduces heat loss, which reduces the required heat load for the boiler and decreases potential GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010*).
4. Economizer: An economizer recovers heat from the boiler stack flue gas and preheats the boiler feed water, which reduces the required heat load for the boiler and decreases potential GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010*).
5. Condensate Return System: Hot condensate is returned to the boiler system to be used as boiler feed water, which reduces the required heat load for the boiler and decreases potential GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010*).
6. Refractory Material Selection: Use of refractory materials that provide the highest insulating capacity reduces heat loss and increases the energy efficiency of the boiler. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010*).

Best Operational Practices

As detailed below, there are several best practices that can be incorporated into the operation or design of the auxiliary boiler:

1. Combustion Air Controls (Limitations on Excess Air/Oxygen): Oxygen monitors and intake air flow monitors can be used to optimize the fuel-to-air ratio and limit excess air, which results in increased combustion efficiency and decreased GHG emissions. Excess air should be limited to approximately 10-15% or lower for a natural gas-fired boiler. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010, Energy Efficiency Improvement and Cost Savings for the Petrochemical Industry, July 2008*).
2. Periodic Maintenance: Maintaining the combustion sources through a maintenance program results in increased average thermal efficiency and energy savings. Maintenance activities include regular calibrations of fuel flow meters and gas composition analyzers and regular cleaning of fouled or dirty parts. A maintenance

plan that contains official documented procedures and a schedule for routine inspections and evaluations can be developed. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Improved Maintenance, November 2010*).

3. Fuel Selection: Firing natural gas or other gaseous fuels results in lower potential GHG emissions, as demonstrated by Table C-1 in 40 CFR Part 98, Subpart C for “General Stationary Fuel Combustion Sources.”

Step 2 – Elimination of Technically Infeasible Options

All options identified in Step 1 are considered technically feasible and therefore need to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Ranking of Remaining Technologies Based on Control Effectiveness

The control technologies specified in Step 1 above are all top-ranked control technologies for industrial boilers. The use of one technology does not preclude the use of any other control technology, and the combination of control technologies and practices will result in higher energy efficiency than any one. However, in order for completeness, the following table lists the technically feasible control technologies and their typical control efficiencies where they are available:

**Table 4-2
Auxiliary Boiler BACT Control Efficiencies**

Item No.	Control Technology Description	Typical Overall Control Eff. (%)	Source
1	Air Pre-Heat System	10-15	GHG BACT for Refineries (Heat Recovery – Air Preheater)
2	Efficient Burner Design	N/A	GHG BACT for ICI Boilers (Replace/Upgrade Burners)
3	Boiler Insulation	6-26	Energy Efficiency Improvement (Section 7.1)
4	Economizer	2-4	GHG BACT for Refineries (Recover Heat from Process Flue Gas)
5	Condensate Return System	1-10% of steam energy use	GHG BACT for Refineries (Install Steam Condensate Return Lines)
6	Refractory Material Selection	N/A	GHG BACT for ICI Boilers (Refractory Material Selection)
7	Combustion Air Controls (Limits on Excess Air)	1-3	GHG BACT for Refineries (Combustion Air Controls – Limitations on Excess Air)
8	Periodic Maintenance	1-10	GHG BACT for Refineries (Improved Maintenance)
9	Fuel Selection	40	40 CFR Part 98, Subpart C, Table C-1, “Default CO emission Factors and High Heat Values for Various Types of Fuel”

Step 4 – Evaluate Control Technologies for Cost-Effectiveness, Energy and Environmental Impacts

All the aforementioned control technologies are considered economically reasonable since this will be a brand new site with the most current technology. The potential control technologies listed will not result in any adverse environmental impacts.

Step 5 – Selection of BACT

CCI proposes that BACT for the auxiliary boiler (EPN: BL-1) is the combination of all the BACT options listed in Step 1.

4.4 PROCESS FLARE

GHG emissions, primarily CO₂, are generated from the combustion of natural gas in maintaining the flare pilot flame. The flare will be utilized to control VOC emissions generated during certain events such as MSS activities and emergency or upset events. CO₂e emissions will be generated during flaring operations.

Step 1 – Identification of Potential Control Technologies

Alternative control technologies for controlling VOC emissions include thermal oxidizers or vapor combustion units (VCU) and vapor recovery units (VRU). The available control technologies for flare operations include the following:

1. Fuel Selection: Firing of natural gas to maintain a pilot flame or as supplemental fuel during VOC control results in lower GHG emissions as demonstrated in 40 CFR Part 98, Subpart C, Table C-1.
2. Proper Flare Operation: The use of flow and composition monitors to determine the optimum amount of supplemental natural gas required to maintain adequate VOC control will minimize natural gas combustion to reduce CO₂ emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Flares, November 2010*).
3. Flare Minimization: Minimize the duration and quantity of flaring associated with MSS activities to the extent practicable through good design and operating practices will result in lower GHG emissions.

Step 2 – Elimination of Technically Infeasible Options

A primary reason in consideration of a flare as a control of VOC emissions is that a flare may also be used in emergency or upset events. Neither a thermal oxidizer nor a VCU are capable of safely handling the potentially high vapor flow rates, high heat inputs, and rapidly changing conditions that are inherent during emergency and upset events. It is not technically feasible to use a thermal oxidizer or VCU as an alternative to a flare. In addition, the use of a thermal oxidizer or VCU will not significantly reduce the amount of GHG emissions as compared to the use of a flare.

Since there will not be any gases routed to the flare from process vents during normal operations, the same technical and safety constraints apply to the use of a VRU as an alternative control device to the flare.

Step 3 – Ranking of Remaining Technologies Based on Control Effectiveness

The technologies applicable to the proposed flare and their typical control efficiencies where available are indicated in the following table:

**Table 4-3
Flare BACT Control Efficiencies**

Control Technology Description	Typical Overall Efficiency (%)	Source
Fuel Selection	40	40 CFR Part 98, Subpart C, Table C-1 “Default CO ₂ Emission Factors and High Heat Values for Various Types of Fuel”
Proper Flare Operation	N/A	GHG BACT for Refineries (Proper Flare Operations)
Flare Minimization	N/A	Up to 100% GHG emission reduction depending on activity type

All the technologies listed in **Table 4-3** above are top-ranked control technologies for flares, and the use of one of these technologies does not preclude the use of any other. A combination of these technologies and practices will achieve a higher reduction of GHG than the use of any one of these control technologies or practices.

Step 4 – Evaluate Control Technologies for Cost-Effectiveness, Energy and Environmental Impacts

All technically feasible control options listed in Step 3 are considered economically reasonable, as the CSF will be a new source and will be able to incorporate into the design the most current technology. The control technologies previously discussed will not have any adverse environmental, economic, or energy impacts.

Step 5 – Selection of BACT

CCI proposes that BACT for the flare consist of a combination of the options listed in **Table 4-3**, which includes the following:

- Fuel Selection: Firing of natural gas to maintain a pilot flame or as supplemental fuel during VOC control;

- Proper Flare Operation: The use of flow and composition monitors to determine the optimum amount of supplemental natural gas required to maintain adequate VOC control;
- Flare Minimization: Minimize the duration and quantity of flaring associated with MSS activities to the extent practicable through good design and operating practices.

4.5 MARINE VAPOR CONTROL UNIT

GHG emissions will be generated from the combustion of VOC vapors captured during the loading of products into marine ships and barges and from supplemental natural gas fuel used to maintain adequate combustion chamber temperature for the required destruction efficiency.

Step 1 – Identification of Potential Control Technologies

The only viable control option for reducing GHG emissions generated during marine/barge loading operations is to minimize the amount of controlled VOC vapors and supplemental gas to the extent possible. Available control technologies for marine vessel loading emissions include:

1. Use of a flare in lieu of a VCU is an alternate control consideration;
2. Use of a VRU in lieu of a VCU is an alternate control consideration;
3. Minimize the duration and quantity of combustion through good engineering design (e.g., submerged loading) and best management practices; and
4. Proper operation and the use of flow and composition monitors to determine the optimum amount of natural gas to maintain adequate VOC destruction efficiency.

Step 2 – Elimination of Technically Infeasible Options

A VCU for control of VOC vapors associated with marine vessel loading operations is being considered primarily due to the higher destruction removal efficiency (DRE) that a VCU is able to achieve (i.e., 99%) over a flare (i.e., 98%). The higher DRE would be required by the TCEQ as BACT for control of non-GHG emissions. Also, it should be noted that the use of a flare for controlling marine vessel loading emissions would not result in a significant reduction of GHG emissions as opposed to the use of a VCU.

VRUs are not capable of handling the large volumes of vapors generally associated with marine vessel loading operations. Therefore, a VRU is a technically infeasible alternative to the use of a VCU for marine loading.

For the reasons discussed above, the use of a flare or VRU are rejected for being technically infeasible control options for marine vessel loading operations. Both minimization and proper operation of the VCU are technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Control Effectiveness

The remaining technologies available for control of vapors generated during marine vessel loading operations from most effective to least effective include:

1. Good engineering design and best operational practices, such as utilizing submerged loading of marine vessels, can reduce GHG emissions;
2. The reduction of GHG emissions resulting from proper operation of the VCU is not directly quantifiable.

CO₂ is the primary GHG resulting from fuel combustion in the VCU. The marine vessel loading facilities will be designed to minimize the volume of loading vapors routed to the VCU. The facilities will utilize submerged loading technology as opposed to splash loading which can equate to up to an 80% concentration reduction in the marine vessel vapor space.

Proper operation will enhance the combustion efficiency of the VCU, resulting in lower GHG emissions; however, this cannot be directly quantified, and the ranking of this technology is an approximation. The use of a thermocouple in the combustion chamber to continuously monitor the chamber temperature will allow instantaneous adjustments to the natural gas fuel supply required to maintain an adequate combustion chamber temperature for proper VOC destruction, ensuring that excess fuel is unnecessarily combusted.

Step 4 – Evaluate Control Technologies for Cost-Effectiveness, Energy and Environmental Impacts

The proposed marine loading facilities will be designed to minimize the volume of vapors routed to the VCU. This will be accomplished through utilization of submerged and/or pressurized loading technologies. There are no adverse environmental, economic, or energy impacts associated with this control technology.

The use of combustion chamber temperature monitors will allow accurate determinations of the required natural gas fuel to maintain the proper temperature necessary for efficient VOC destruction while keeping excess natural gas fuel to a minimum. This will provide the added

advantage of reducing fuel costs, thus making this control technology cost effective as both a GHG emission control and a viable control for VOC emissions. There are no adverse environmental, economic, or energy impacts associated with this control technology.

Step 5 – Selection of BACT

CCI proposes that BACT for marine loading is a vapor combustor. GHG emissions from the VCU will be minimized using good engineering design and best operational practices.

4.6 FUGITIVE EMISSIONS

Emissions from leaking piping components (process fugitives) can potentially include methane. The contribution of GHG emissions from process fugitives has conservatively been estimated to be 96.68 tpy which is a negligible amount to the total site GHG emissions. For completeness, GHG process fugitives are included in this BACT analysis.

Step 1 – Identification of Potential Control Technologies

1. Installation of Leakless Technology: The utilization of leakless technology components such as welded components would eliminate the potential of GHG emissions from process fugitives.
2. Implementation of a Leak Detection and Repair (LDAR) Program: The use of a portable organic vapor detector that meets the specifications and performance criteria specified in 40 CFR, Part 60, Appendix A, Test Method 21 in to monitor piping components for leaks will result in decreased emissions of GHG as well as other criteria pollutant emissions. As LDAR programs are not considered as control options for GHG emissions alone, and due to the negligible contribution of GHG emissions from leaking components, an evaluation of the relative effectiveness of various LDAR programs is not warranted. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Fuel Gas System, November 2010*).
3. Alternative Monitoring Using Infrared Technology: This control technology is similar to an LDAR program; however, a sensitive infrared (IR) camera to detect piping component leaks is used in lieu of a portable organic vapor detector.
4. Compressor Selection: The use of dry-seal compressors rather than wet-seal compressors and rod packing for reciprocating compressors will result in reduced GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Fuel Gas System, November 2010*).

Step 2 – Elimination of Technically Infeasible Options

All control technologies identified in Step 1 are technically feasible options for controlling GHG emissions and are considered in Step 3 below.

Step 3 – Ranking of Remaining Technologies Based on Control Effectiveness

Leakless Technology

Installation of leakless technology would result in 100% control of GHG emissions from piping components and is the most effective control technology.

LDAR Program

LDAR programs are generally designed for control of VOC emissions from leaking piping components and piping components in natural gas service where methane is the primary GHG constituent and have not historically been required for monitoring under existing LDAR Programs. As such, there is no information relating to the effectiveness of an LDAR program in controlling GHG, so the same control efficiencies applied to the control of VOC emissions with a given LDAR program have been applied to the efficiency of control for GHG. As stated in Step 1, a comparative evaluation of the effectiveness of various LDAR programs available is not warranted in this BACT analysis.

Alternative Monitoring

The use of an IR camera for piping component leak detection is considered by the United States Environment Protection Agency (EPA) to be a partial alternative monitoring technology to Test Method 21. This may be interpreted that the monitoring methods are equivalent if, in addition to IR monitoring, piping components are also monitored as specified in Test Method 21 annually. The control effectiveness of an alternative monitoring technology alone may be assumed to be 75% based on TCEQ's 28VHP LDAR program for connector monitoring.

Compressor Selection

The use of dry-seal compressors and rod packing for reciprocating compressors are considered effective means of controlling GHG emissions; however, there is no available data to support specific control effectiveness.

Step 4 – Evaluate Control Technologies for Cost-Effectiveness, Energy and Environmental Impacts

Leakless Technology

Although leakless technology is the most effective means of controlling potential emissions from fugitive components, it has not been adopted as BACT for any sources to date. In addition, the installation of leakless technologies in any process would create increased collateral emissions associated with maintenance activities that require replacement or repair of vessels or piping. The use of leakless technology is not a cost-effective means for controlling fugitive emissions as it would increase costs for controlling emissions associated with maintenance activities. The control of maintenance-related emissions would require a higher energy demand and would increase the potential of adverse environmental impacts.

LDAR Program

Though it is technically feasible to use an LDAR program to control the negligible amount of GHG emissions that occur as leaks from process fugitive components, it is also cost prohibitive if used solely for the control of GHG emissions. However, the implementation of an LDAR program for control of VOC emissions from process fugitive components will result in the added control of GHG emissions from those same process fugitive components. The use of an LDAR program for controlling GHG emissions would not impose an additional cost, require higher energy demand, or result in adverse environmental impacts.

Compressor Design

The use of dry-seal compressors and rod packing for reciprocating compressors are cost effective means for controlling GHG emissions as well as emissions from other criteria pollutants. This control technology would not impose an adverse impact on energy demand or the environment.

Step 5 – Selection of BACT

Because of the negligible amount of GHG emissions from process fugitive components, the implementation of an LDAR program strictly for control of GHG emissions is cost prohibitive. However, CCI proposes the implementation of an appropriate LDAR program to control VOC emissions, which would also decrease GHG emissions. The TCEQ has determined that the

appropriate LDAR program to meet BACT for VOC emissions at the proposed CSF is the 28VHP, and CCI will implement this program. CCI will also install compressors that meet seal and rod packing requirements.

4.7 EMERGENCY GENERATOR AND FIREWATER PUMP ENGINES

Emergency generators and firewater pump engines will be used for emergency purposes only; however, this equipment will be operated for testing purposes.

Step 1 – Identification of Potential Control Technologies

The RBLC database currently does not include control technologies for GHG emissions from emergency use engines. Control technologies considered for emergency generator and firewater pump engines include:

1. Good combustion practices and maintenance; and
2. Limited operation.

Step 2 – Elimination of Technically Infeasible Options

The identified control technologies in Step 1 are all technically feasible as GHG emission control options.

Step 3 – Ranking of Remaining Technologies Based on Control Effectiveness

The control options identified above are all effective means of minimizing GHG emissions from emergency generator and firewater pump engines, however there is not sufficient data to rank these control options by effectiveness.

Step 4 – Evaluate Control Technologies for Cost-Effectiveness, Energy and Environmental Impacts

All of the control technologies identified in Step 1 are cost effective in controlling GHG emissions from emergency engines, and implementation of these technologies would not have an adverse effect on energy demand or on the environment.

Step 5 – Selection of BACT

CCI proposes to install high efficiency emergency generator and firewater pump engines utilizing diesel fuel that complies with the standards set forth in 40 CFR Part 60, Subpart III, *Standards of Performance for Stationary Compression Ignition Combustion Engines*.

CCI will properly operate and maintain emergency engines to minimize GHG emissions and will limit normal operation of the emergency engines for scheduled testing purposes to 500 hours per year.

US EPA ARCHIVE DOCUMENT

**APPENDIX A
ADMINISTRATIVE INFORMATION**

Administrative Information

I. Applicant Information		
A. Company or Other Legal Name: CCI Corpus Christi, LLC		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name: Brad Burmaster		
Title: Vice President		
Mailing Address: 811 Main St, Suite 3500		
City: Houston	State: Texas	ZIP Code: 77002
Telephone No.: (281)378-1190	Fax No.:	E-mail Address: Brad.burmaster@cci.com
C. Technical Contact Name: Leann Plagens		
Title: Director of Regulatory Compliance		
Company Name: CCI Corpus Christi, LLC		
Mailing Address: 811 Main St, Suite 3500		
City: Houston	State: Texas	ZIP Code: 77002
Telephone No.: (281)378-1257	Fax No.:	E-mail Address: Leann.plagens@cci.com
D. Site Name: CCI Corpus Christi Condensate Splitter Facility		
E. Area Name/Type of Facility: Condensate Splitter	<input checked="" type="checkbox"/> Permanent <input type="checkbox"/> Portable	
F. Principal Company Product or Business: Refined Petroleum Products		
Principal Standard Industrial Classification Code (SIC): 2911		
Principal North American Industry Classification System (NAICS): 324110		
G. Projected Start of Construction Date: November 2014		
Projected Start of Operation Date: June 2015		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 4820 E. Navigation Boulevard (Carbon Plant Rd.)		
City/Town: Corpus Christi	County: Nueces	ZIP Code: 78402
Latitude (nearest second):		Longitude (nearest second):

APPENDIX B
TECHNICAL APPLICATION TABLES

CCI Corpus Christi LLC
Table 1(a) Emission Point Summary

Date: 10/29/2013	Permit No.: TBD	Regulated Entity No.: TBD
Area Name: CCI Corpust Christi	Customer Reference No.: TBD	

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			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate		4. UTM Coordinates of Emissions Point			Source								
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY	Zone	East (Meters)	North (Meters)	5. Building Height (Ft.)	6. Height Above Ground (Ft.)	7. Stack Exit Data			8. Fugitives			
										(A) Diameter (Ft.)	(B) Velocity (FPS)	(C) Temperature (°F)	(A) Length (Ft.)	(B) Width (Ft.)	(C) Axis Degrees		
H-1	H-1	Preheater 1	CO ₂	17,843.25	70,338.10	14	649,294	3,079,041	--	TBD	TBD	TBD	TBD	--	--	--	
			CH ₄	0.34	1.33												
			N ₂ O	0.03	0.13												
			CO ₂ e	17,860.75	70,407.08												
H-2	H-2	Preheater 2	CO ₂	17,843.25	70,338.10	14	649,347	3,079,000	--	TBD	TBD	TBD	TBD	--	--	--	
			CH ₄	0.34	1.33												
			N ₂ O	0.03	0.13												
			CO ₂ e	17,860.75	70,407.08												
BL-1	BL-1	Boiler	CO ₂	4,243.45	16,510.34	14	649,379	3,078,926	--	TBD	TBD	TBD	TBD	--	--	--	
			CH ₄	0.08	0.31												
			N ₂ O	0.01	0.03												
			CO ₂ e	4,247.61	16,526.53												
FL-1	FL-1	Flare	CO ₂	506.39	2,016.37	14	649,643	3,078,574	--	TBD	TBD	TBD	TBD	--	--	--	
			CH ₄	1.56	6.20												
			N ₂ O	<0.01	<0.01												
			CO ₂ e	539.37	2,147.70												
FL-MSS	FL-MSS	Flare-MSS	CO ₂	157,717.63	473.15	14	649,643	3,078,574	--	TBD	TBD	TBD	TBD	--	--	--	
			CH ₄	15.36	0.05												
			N ₂ O	0.23	<0.01												
			CO ₂ e	158,112.16	474.34												

CCI Corpus Christi LLC
Table 1(a) Emission Point Summary

Date: 10/29/2013	Permit No.: TBD	Regulated Entity No.: TBD
Area Name: CCI Corpust Christi	Customer Reference No.: TBD	

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			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate		4. UTM Coordinates of Emissions Point			Source								
									7. Stack Exit Data			8. Fugitives					
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY	Zone	East (Meters)	North (Meters)	5. Building Height (Ft.)	6. Height Above Ground (Ft.)	(A) Diameter (Ft.)	(B) Velocity (FPS)	(C) Temperature (°F)	(A) Length (Ft.)	(B) Width (Ft.)	(C) Axis Degrees	
EMGEN	EMGEN	Emergency Generator	CO ₂	2,446.23	122.31	14	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--	
			CH ₄	0.10	<0.01												
			N ₂ O	0.02	<0.01												
			CO ₂ e	2,454.46	122.72												
FW-1	FW-1	Firewater Pump-1	CO ₂	815.41	40.77	14	649,431	3,078,910	--	TBD	TBD	TBD	TBD	--	--	--	
			CH ₄	0.03	<0.01												
			N ₂ O	0.01	<0.01												
			CO ₂ e	818.15	40.91												
FW-2	FW-2	Firewater Pump-2	CO ₂	815.41	40.77	14	649,431	3,078,910	--	TBD	TBD	TBD	TBD	--	--	--	
			CH ₄	0.03	<0.01												
			N ₂ O	0.01	<0.01												
			CO ₂ e	818.15	40.91												
MVCU	MVCU	Mraine Vapor Combuster Unit	CO ₂	14,402.89	8,151.27	14	649,252	3,078,668	--	TBD	TBD	TBD	TBD	--	--	--	
			CH ₄	0.40	0.23												
			N ₂ O	0.06	0.04												
			CO ₂ e	14,430.23	8,167.11												
FUG	FUG	Fugitives	CO ₂	-	-	14	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--	
			CH ₄	1.10	4.84												
			N ₂ O	-	-												
			CO ₂ e	23.18	101.54												

EPN = EMISSION POINT NUMBER

FIN = FACILITY IDENTIFICATION NUMBER

This form designed to correspond with TCEQ - 10153 (Revised 04/08) Table 1(a).

**APPENDIX C
PSD TABLES**



**TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT**

US EPA ARCHIVE DOCUMENT

Permit No.: <i>TBD</i>		Application Submittal Date: <i>TBD</i>							
Company: <i>CCI Corpus Christi, LLC</i>									
RN:		Facility Location: <i>4820 E Navigation Boulevard</i>							
City: <i>Corpus Christi</i>		County: <i>Nueces</i>							
Permit Unit I.D.:		Permit Name: <i>TBD</i>							
Permit Activity: <input checked="" type="checkbox"/> New Source <input type="checkbox"/> Modification									
Complete for all Pollutants with a Project Emission Increase.		POLLUTANTS							
		Ozone		CO	PM₁₀	PM_{2.5}	NO_x	SO₂	Other¹ CO_{2e}
		VOC	NO_x						
Nonattainment?								<i>NO</i>	
PSD?								<i>YES</i>	
Existing site PTE (tpy)?								<i>NA</i>	
Proposed project emission increases (tpy from 2F ²)?								<i>168,435</i>	
Is the existing site a major source?								<i>NA</i>	
If not, is the project a major source by itself?								<i>YES</i>	
If site is major source, is project increase significant?								<i>YES</i>	
If netting required, estimated start of construction: <i>November 2014</i>									
5 years prior to start of construction: <i>November 2009</i>				contemporaneous					
Estimated start of operation: <i>June 2015</i> period									
Net contemporaneous change, including proposed project, from Table 3F. (tpy)								<i>NA</i>	
Major NSR Applicable?								<i>NO</i>	
_____		_____			_____				
<i>Signature</i>		<i>Title</i>			<i>Date</i>				

¹ Other pollutants. [Pb, H₂S, TRS, H₂SO₄, Fluoride excluding HF, etc.]

² Sum of proposed emissions minus baseline emissions, increases only.

The representations made above and on the accompanying tables are true and correct to the best of my knowledge.

**TABLE 2F
PROJECT EMISSION INCREASE**

Pollutant ⁽¹⁾ : CO ₂ e			Permit: TBD							
Baseline Period: Not applicable (proposed new stationary source)										
Affected or Modified Facilities ⁽²⁾			Permit No.	A		B		Difference (B-A) ⁽⁶⁾	Correction ⁽⁷⁾	Project Increase ⁽⁸⁾
				Actual Emissions ⁽³⁾	Baseline Emissions ⁽⁴⁾	Proposed Emissions ⁽⁵⁾	Projected Actual Emissions			
FIN	EPN									
1	H-1	H-1	TBD	-	-	70,407.08	-	70,407.08		70,407.08
2	H-2	H-2	TBD	-	-	70,407.08	-	70,407.08		70,407.08
3	BL-1	BL-1	TBD	-	-	16,526.53	-	16,526.53		16,526.53
4	FL-1	FL-1	TBD	-	-	2,147.70	-	2,147.70		2,147.70
5	FL-MSS	FL-MSS	TBD	-	-	474.34	-	474.34		474.34
6	EMGEN	EMGEN	TBD	-	-	122.72	-	122.72		122.72
7	FW-1	FW-1	TBD	-	-	40.91	-	40.91		40.91
8	FW-2	FW-2	TBD	-	-	40.91	-	40.91		40.91
9	MVCU	MVCU	TBD	-	-	8,167.11	-	8,167.11		8,167.11
10	FUG	FUG	TBD	-	-	101.54	-	101.54		101.54
								Page Subtotal⁽⁹⁾	0.00	168,435.91

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

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

**APPENDIX D
EMISSION CALCULATIONS**

**Table D-1
Summary of Potential to Emit
CCI Corpus Christi LLC**

A. Annual Potential to Emit (PTE) Summary

Emission Source Description	Potential Annual Emissions (tons/year) ⁽¹⁾				Reference Table
	CO ₂	CH ₄	N ₂ O	CO ₂ e	
Preheater (H-1)	70,338.10	1.33	0.13	70,407.08	D-2
Preheater (H-2)	70,338.10	1.33	0.13	70,407.08	D-2
Boiler (BL-1)	16,510.34	0.31	0.03	16,526.53	D-2
Flare (FL-1)	2,016.37	6.20	<0.01	2,147.70	D-3
Flare-MSS (FL-MSS)	473.15	0.05	<0.01	474.34	D-4
Emergency Generator (EMGEN)	122.31	<0.01	<0.01	122.72	D-5
Fire Water Pump (FW-1)	40.77	<0.01	<0.01	40.91	D-5
Fire Water Pump (FW-2)	40.77	<0.01	<0.01	40.91	D-5
Marine Vapor Cumbuster (MVCU)	8,151.27	0.23	0.04	8,167.11	D-6
Fugitives (FUG)	-	4.84	-	101.54	D-7
Total Proposed PTE	168,031.18	14.28	0.34	168,435.91	Totals
Major Source Threshold	NA	NA	NA	100,000	
Triggers Major Source Permitting?	NA	NA	NA	Yes	

Notes:

(1) All sources associated with this project are new sources; therefore, baseline emissions are zero and the total emissions increases for purposes of federal applicability are equal to the PTEs.

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**Table D-1
Summary of Potential to Emit
CCI Corpus Christi LLC**

B. Hourly Potential To Emit (PTE) Summary

Emission Source Description	Potential Hourly Emissions (lb/hour)				Reference Table
	CO ₂	CH ₄	N ₂ O	CO ₂ e	
Preheater (H-1)	17,843.25	0.34	0.03	17,860.75	D-2
Preheater (H-2)	17,843.25	0.34	0.03	17,860.75	D-2
Boiler (BL-1)	4,243.45	0.08	0.01	4,247.61	D-2
Flare (FL-1)	506.39	1.56	<0.01	539.37	D-3
Flare-MSS (FL-MSS)	157,717.63	15.36	0.23	158,112.16	D-4
Emergency Generator (EMGEN)	2,446.23	0.10	0.02	2,454.46	D-5
Fire Water Pump (FW-1)	815.41	0.03	0.01	818.15	D-5
Fire Water Pump (FW-2)	815.41	0.03	0.01	818.15	D-5
Marine Vapor Cumbuster (MVCU)	14,402.89	0.40	0.06	14,430.23	D-6
Fugitives (FUG)	-	1.10	-	23.18	D-7
Total Proposed PTE	216,633.90	19.34	0.40	217,164.83	

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**Table D-2
Preheaters and Boilers - Potential Emissions
CCI Corpus Christi LLC**

A. Emission Factors and Global Warming Potential (GWP) Equivalency Factors

CO ₂ ⁽¹⁾	53.02 kg CO ₂ /MMBtu	&	CO ₂ ⁽²⁾	=	1 ton of CO ₂ equivalent
CH ₄ ⁽¹⁾	0.001 kg CH ₄ /MMBtu	&	CH ₄ ⁽²⁾	=	21 tons of CO ₂ equivalent
N ₂ O ⁽¹⁾	0.0001 kg N ₂ O/MMBtu	&	N ₂ O ⁽²⁾	=	310 tons of CO ₂ equivalent

B. Emission Calculations

Emission Source	Design Firing Rate ⁽³⁾		CO ₂ Emissions ⁽⁴⁾⁽⁵⁾		CH ₄ Emissions ⁽⁴⁾⁽⁵⁾		N ₂ O Emissions ⁽⁴⁾⁽⁵⁾		CO ₂ e Emissions ⁽⁶⁾	
	Maximum MMBtu/hr	Average MMBtu/hr	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Condensate Preheater (H-1)	152.6	137.4	17,843	70,338	0.34	1.33	0.03	0.13	17,861	70,407
Condensate Preheater (H-2)	152.6	137.4	17,843	70,338	0.34	1.33	0.03	0.13	17,861	70,407
Boiler (BL-1)	36.3	32.2	4,243	16,510	0.08	0.31	0.01	0.03	4,248	16,527
Subtotal			39,930	157,187	0.75	2.96	0.08	0.30	39,969.11	157,340.69

Notes:

- (1) Emission factors are based on 40 CFR Part 98 Subpart C, Table C-1 and Table C-2 for natural gas.
- (2) Global warming potential factors are based on 40 CFR Part 98 Subpart A, Table A-1.
- (3) Maximum and average heating values are fuel heat input values as fired on a higher heating value (HHV) basis. The data provided by design specified for the CCI heater was assumed to be absorbed duty on a LHV basis, and this value was adjusted by multiplying by a 1.11 HHV/LHV ratio and dividing by a 85% for heater efficiency.
- (4) Hourly emissions are based on the emission factor * max. hourly firing rate * 2.205 lb/kg.
- (5) Annual emissions are based on the emission factor * aver. hourly firing rate (normal) * 2.205 lb/kg * 8,760 hours/year / 2000 lb/ton
- (6) CO₂e emissions are based on the sum of the CO₂, CH₄, and N₂O emissions times their respective GWP factors.

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Table D-3
Flare - Pilot and Normal Operation Emission Calculations
CCI Corpus Christi LLC

A. Pilot Gas Emissions

Parameter Name & Variable	Value & Units	Basis/Calculations/Notes
1. General Values and Calculations		
Hourly Flow Rate F_H	451 scf/hr	Based on process knowledge
Annual Flow Rate F_A	3,592,000 scf/yr	Based on process knowledge
Heat Content H	1,020 Btu/scf	Typical Heat Content of Natural Gas
2. CO₂ Emission Rate Calculations		
CO ₂ Emission Factor F_{CO_2}	116.91 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-1
CO ₂ Hourly Emission Rate	53.78 lb/hr	$= F_H \times (H / 1,000,000 \text{ Btu/MMBtu}) \times F_{CO_2}$
CO ₂ Annual Emission Rate	214.17 tpy	$= F_A \times (H / 1,000,000 \text{ Btu/MMBtu}) \times F_{CO_2} / 2,000 \text{ lb/ton}$
3. CH₄ Emission Rate Calculations		
CH ₄ Emission Factor F_{CH_4}	0.00221 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2
CH ₄ Hourly Emission Rate ER_{CH_4}	<0.01 lb/hr	$= F_H \times (H / 1,000,000 \text{ Btu/MMBtu}) \times F_{CH_4}$
CH ₄ Annual Emission Rate ER_{CH_4}	<0.01 tpy	$= F_A \times (H / 1,000,000 \text{ Btu/MMBtu}) \times F_{CH_4} / 2,000 \text{ lb/ton}$
Hourly Global Warming Potential GWP_{CH_4}	0.02 lb/hr	$= ER_{CH_4} \times 21 \text{ CO}_2\text{e}$
Annual Global Warming Potential GWP_{CH_4}	0.08 tpy	$= ER_{CH_4} \times 21 \text{ CO}_2\text{e}$
4. N₂O Emission Rate Calculations		
N ₂ O Emission Factor F_{N_2O}	0.00022 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2
N ₂ O Hourly Emission Rate ER_{N_2O}	<0.01 lb/hr	$= F_H \times (H / 1,000,000 \text{ Btu/MMBtu}) \times F_{N_2O}$
N ₂ O Annual Emission Rate ER_{N_2O}	<0.01 tpy	$= F_A \times (H / 1,000,000 \text{ Btu/MMBtu}) \times F_{N_2O} / 2,000 \text{ lb/ton}$
Hourly Global Warming Potential GWP_{N_2O}	0.03 lb/hr	$= ER_{N_2O} \times 310 \text{ CO}_2\text{e}$
Annual Global Warming Potential GWP_{N_2O}	0.13 tpy	$= ER_{N_2O} \times 310 \text{ CO}_2\text{e}$
5. Total CO₂e Emission Rates		
Hourly Global Warming Potential	53.83 lb/hr	$= ER_{CO_2} + GWP_{CH_4} + GWP_{N_2O}$
Annual Global Warming Potential	214.38 tpy	$= ER_{CO_2} + GWP_{CH_4} + GWP_{N_2O}$

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**Table D-3
Flare - Pilot and Normal Operation Emission Calculations
CCI Corpus Christi LLC**

B. Waste Gas/Supplemental Natural Gas

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes	
1. General Values and Calculations			
Hourly Vapor Volume to Flare Q_H	3,850 scf/hr	Based on Estimated Flow to Flare	
Annual Vapor Volume to Flare Q_A	30,660,000 scf/yr	Based on Estimated Flow to Flare	
Hourly Vapor Mass to Flare M_H	164 lb/hr	= $Q_H \times MW / 385 \text{ scf/lb-mol}$	
Annual Vapor Mass to Flare M_A	1,306,794 lb/year	= $Q_A \times MW / 385 \text{ scf/lb-mol}$	
Gas Heat Content H_v	939 Btu/scf	Based on gas composition and heat content of each constituent	
Max. Hourly Vapor Heat Input to Flare H_H	3.6 MMBtu/hr	= $Q_H \times H_v / 1000000$	
Annual Vapor Heat Input to Flare H_A	28,777 MMBtu/yr	= $Q_A \times H_v / 1000000$	
2. Gas Composition			
	Volume %	MW	
N ₂ Volume Percent & Molecular Weight	0.03	28.00	Based on Typical Stream Composition
CO ₂ Volume Percent & Molecular Weight	0.05	44.01	Based on Typical Stream Composition
CH ₄ Volume Percent & Molecular Weight	97.40	16.00	Based on Typical Stream Composition
C ₂ H ₆ Volume Percent & Molecular Weight	2.22	30.07	Based on Typical Stream Composition
VOC Volume Percent & Molecular Weight	0.33	45.37	Based on Typical Stream Composition
Total Molecular Weight MW_T	16.43 lb/lb-mol		Based on Typical Stream Composition
3. CO₂ Emission Rate Calculations			
Carbon Content CC	0.75	= $\Sigma (\text{No. of Carbons} * 12 * \text{Mass}\%_i / MW_i)$	
CO ₂ Hourly Emission Rate ER_{CO2H}	453 lb/hr	= $44/12 * Q_H * CC * MW_T / 385 \text{ scf/lb-mol}$	
CO ₂ Annual Emission Rate ER_{CO2A}	1,802 tpy	= $44/12 * Q_A * CC * MW_T / 385 \text{ scf/lb-mol} / 2,000 \text{ lb/ton}$	
4. CH₄ Emission Rate Calculations			
CH ₄ Weight Percent W_{CH4}	94.84 %		
Flare DRE for CH ₄ %	99 %	TCEQ Flare Guidance Document (October 2000)	
CH ₄ Hourly Emission Rate ER_{CH4H}	1.56 lb/hr	= $W_{CH4} * M_H * (100\% - \text{DRE})$	
CH ₄ Annual Emission Rate ER_{CH4A}	6.20 tpy	= $W_{CH4} * M_A * (100\% - \text{DRE}) / 2000 \text{ lb/ton}$	
Hourly Global Warming Potential GWP_{CH4H}	33 lb/hr	= $ER_{CH4H} * 21 \text{ CO}_2\text{e}$	
Annual Global Warming Potential GWP_{CH4A}	130 tpy	= $ER_{CH4A} * 21 \text{ CO}_2\text{e}$	
5. N₂O Emission Rate Calculations			
N ₂ O Emission Factor F_{N2O}	0.00022 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2	
N ₂ O Hourly Emission Rate ER_{N2OH}	<0.01 lb/hr	= $H_H * F_{N2O}$	
N ₂ O Annual Emission Rate ER_{N2OA}	<0.01 tpy	= $H_A * F_{N2O} / 2000 \text{ lbs/ton}$	
Hourly Global Warming Potential GWP_{N2OH}	0.25 lb/hr	= $ER_{N2OH} * 310 \text{ CO}_2\text{e}$	
Annual Global Warming Potential GWP_{N2OA}	0.98 tpy	= $ER_{N2OA} * 310 \text{ CO}_2\text{e}$	
6. Total CO₂e Emission Rates			
Hourly Global Warming Potential -	486 lb/hr	= $ER_{CO2H} + GWP_{CH4H} + GWP_{N2OH}$	
Annual Global Warming Potential -	1,933 tpy	= $ER_{CO2A} + GWP_{CH4A} + GWP_{N2OA}$	

**Table D-4
Flare - Startup/Shutdown Flaring MSS Emission Calculations
CCI Corpus Christi LLC**

A. Waste Gas Flaring Scenario

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
Volumetric Flow Rate	0.38 MMScf/hr	Startup/shutdown flow rate is based on design
Fuel Heating Value (LHV)	2,756 Btu/Scf	= $\sum (\text{Volume } \%_i * \text{HV}_i)$
Molecular Weight	53.08 lb/lb-mole	= $\sum (\text{Volume } \%_i * \text{MW}_i)$
Flaring Frequency	6 hours/yr	Based on process knowledge
Carbon Content	0.82	= $\sum (\text{No. of Carbons} * 12 * \text{Mass}\%_i / \text{MW}_i)$

Waste Gas Composition	Volume %	MW	HV	No. of C	
Water Chemical Properties	3.57	18.02	0	0	Based on engineering estimate of average gas composition. *MW = Molecular weight of compound *HV = Lower heating value of compound in Btu/scf *No. of C = Number of carbons in compound
Methane Chemical Properties	10.65	16.04	911	1	
Ethane Chemical Properties	5.14	30.07	1,631	2	
Propane Chemical Properties	20.94	44.10	2,353	3	
Isobutane Chemical Properties	11.54	58.12	3,094	4	
n-butane Chemical Properties	20.28	58.12	3,101	4	
Isopentane Chemical Properties	9.53	72.15	3,698	5	
n-pentane Chemical Properties	7.62	72.15	3,709	5	
Methylcyclopentane Chemical Properties	0.34	84.16	4,199	6	
Cyclohexane Chemical Properties	0.36	84.16	4,180	6	
Cyclopentane Chemical Properties	0.79	70.10	3,512	5	
Benzene Chemical Properties	0.34	78.11	3,591	6	
C6+ Chemical Properties	8.90	86.18	4,404	6	

Hourly Waste Gas Flaring Emissions			
Pollutant	Emission Factor	Activity Level ⁽¹⁾	Calculated Hourly PTE ⁽⁷⁾
CO ₂	0.82 Carbon Content	0.38 MMScf/hr	157,718 lb/hr
CH ₄	2.912 wt% CH ₄ (2) ; 99% DRE (3)	52,746 lb/hr	15.36 lb/hr
N ₂ O	0.00022 lb/MMBtu (4)	1,055 MMBtu/hr	0.23 lb/hr
CO ₂ e	F _{GWP,CO2} = 1 ; F _{GWP,CH4} = 21 ; F _{GWP,N2O} = 310 (5)		158,112 lb/hr

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Table D-4
Flare - Startup/Shutdown Flaring MSS Emission Calculations
CCI Corpus Christi LLC

Annual Waste Gas Flaring Emissions			
Pollutant	Emission Factor	Activity Level ⁽⁶⁾	Calculated Annual PTE ⁽⁷⁾
CO ₂	0.82 Carbon Content	2 MMScf/yr	473 tpy
CH ₄	2.912 wt% CH ₄ (2) ; 99% DRE (3)	316,476 lb/yr	0.05 tpy
N ₂ O	0.00022 lb/MMBtu (4)	6,333 MMBtu/yr	<0.01 tpy
CO ₂ e	F _{GWP,CO2} = 1 ; F _{GWP,CH4} = 21 ; F _{GWP,N2O} = 310 (5)		474 tpy

Notes:

- (1) The maximum hourly activity levels are based on a maximum flaring rate of 0.38 MMScf/hr during startup and shutdown.
- (2) CH₄ content based on typical stream composition.
- (3) Flare destruction removal efficiency (DRE) based on TCEQ Flare Guidance Document (October 2000).
- (4) N₂O emission factor based on 40 CFR Part 98, Subpart C, Table C-2 for natural gas.
- (5) The global warming potentials are based on 40 CFR 98, Subpart A, Table A-1.
- (6) The annual average activity levels are based on a maximum flaring rate of 0.38 MMScf/hr during start-ups and shutdowns, a start-up/shutdown duration of 6 hours/year, and the site-specific stream properties.

(7) Example Calculations:

Flaring Emissions

$$\text{Hourly PTE (lb/hr)} = 44/12 * \text{Max Gas Flow (MMScf/hr)} * 1,000,000 * \text{Carbon Content} * \text{Molecular Weight (lb/lb-mole)} / 385 \text{ scf/lb-mol}$$

CO₂:

$$\text{Annual PTE (tpy)} = \text{Hourly PTE (lb/hr)} * \text{Duration of Flaring Scenario (hr/yr)} / 2,000 \text{ lb/ton}$$

$$\text{Hourly PTE (lb/hr)} = \text{Max Gas Flow (MMScf/hr)} * 1,000,000 * \text{Molecular Weight (lb/lb-mole)} / 385 \text{ scf/lb-mol} * \text{wt\% CH}_4 * (100 - \text{DRE})$$

CH₄:

$$\text{Annual PTE (tpy)} = \text{Hourly PTE (lb/hr)} * \text{Duration of Flaring Scenario (hr/yr)} / 2,000 \text{ lb/ton}$$

$$\text{Hourly PTE (lb/hr)} = \text{Max Gas Flow (MMScf/hr)} * \text{Heating Value (Btu/Scf)} * \text{Emission Factor (lb/MMBtu)}$$

N₂O:

$$\text{Annual PTE (tpy)} = \text{Hourly PTE (lb/hr)} * \text{Duration of Flaring Scenario (hr/yr)} / 2,000 \text{ lb/ton}$$

$$\text{Hourly PTE (lb/hr)} = 1 * \text{CO}_2 \text{ Hourly PTE (lb/hr)} + 21 * \text{CH}_4 \text{ Hourly PTE (lb/hr)} + 310 * \text{N}_2\text{O Hourly PTE (lb/hr)}$$

CO₂e:

$$\text{Annual PTE (tpy)} = 1 * \text{CO}_2 \text{ Annual PTE (tpy)} + 21 * \text{CH}_4 \text{ Annual PTE (tpy)} + 310 * \text{N}_2\text{O Annual PTE (tpy)}$$

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**Table D-5
Emergency Equipment - Potential Emissions
CCI Corpus Christi LLC**

A. Emission Factors and Global Warming Potential (GWP) Equivalency Factors

$\text{CO}_2^{(1)}$	73.96 kg CO_2 /MMBtu	&	$\text{CO}_2^{(2)}$	=	1 ton of CO_2 equivalent
$\text{CH}_4^{(1)}$	0.003 kg CH_4 /MMBtu	&	$\text{CH}_4^{(2)}$	=	21 tons of CO_2 equivalent
$\text{N}_2\text{O}^{(1)}$	0.0006 kg N_2O /MMBtu	&	$\text{N}_2\text{O}^{(2)}$	=	310 tons of CO_2 equivalent

B. Emission Calculations

Emission Source	Design Firing Rate		CO_2 Emissions		CH_4 Emissions		N_2O Emissions		CO_2e Emissions ⁽⁵⁾	
	Maximum MMBtu/hr	Usage (hrs/year)	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Emergency Generator (EMGEN)	15.0	100	2,446	122	0.10	0.005	0.020	0.001	2,454	123
Fire Water Pump (FW-1)	5.0	100	815	41	0.03	0.002	0.007	0.0003	818	41
Fire Water Pump (FW-2)	5.0	100	815	41	0.03	0.002	0.007	0.0003	818	41

Notes:

- (1) Emission factors are based on 40 CFR Part 98 Subpart C, Table C-1 and Table C-2 for distillate fuel oil no.2
- (2) Global warming potential factors are based on 40 CFR Part 98 Subpart A, Table A-1.
- (3) Hourly emissions are based on the emission factor * max. hourly firing rate * 2.204 lb/kg.
- (4) Annual emissions are based on the emission factor * max.hourly firing rate * 2.204 lb/kg * 100 hours/year / 2000 lb/ton
- (5) CO_2e emissions are based on the sum of the CO_2 , CH_4 , and N_2O emissions times their respective GWP factors.

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**Table D-6
Vapor Combustion Units (MVCU) - Potential Emissions
CCI Corpus Christi LLC**

A. Pilot and Enrichment Gas VCU Emission Calculations

CO ₂ Emission Factor ⁽¹⁾ =	53.02 kg CO ₂ /MMBtu	&	CO ₂ GWP ⁽²⁾ =	1 ton of CO ₂ equivalent
CH ₄ Emission Factor ⁽¹⁾ =	0.001 kg CH ₄ /MMBtu	&	CH ₄ GWP ⁽²⁾ =	21 tons of CO ₂ equivalent
N ₂ O Emission Factor ⁽¹⁾ =	0.0001 kg N ₂ O/MMBtu	&	N ₂ O GWP ⁽²⁾ =	310 tons of CO ₂ equivalent
Pilot Gas Maximum Flow =	99 scf/hr	Pilot Gas Average Flow =	788,000 scf/yr	
Enrichment Gas Maximum Flow =	79,260 scf/hr	Enrichment Gas AverageFlow =	86,804,000 scf/yr	
NG Heat Content =	1,020 Btu/scf	NG Heat Content =	1,020 Btu/scf	
Pilot Gas Heat Input =	0.101 MMBtu/hr	Pilot Gas Heat Input =	804 MMBtu/yr	
Enrichment Gas Heat Input =	80.845 MMBtu/hr	Enrichment Gas Heat Input =	88,540 MMBtu/yr	

Pilot and Enrichment Gas Emission Calculations (Natural Gas)

Emission Source	CO ₂ Emissions		CH ₄ Emissions		N ₂ O Emissions		CO ₂ e Emissions ⁽³⁾	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
MVCU-Pilot	12	47	<0.01	<0.01	<0.01	<0.01	12	47
MVCU-Enrichment Gas	9,452	5,176	0.18	0.10	0.02	<0.01	9,461	5,181

**Table D-6
Vapor Combustion Units (MVCU) - Potential Emissions
CCI Corpus Christi LLC**

B. VCU Controlled GHG Emissions

Annual vapors to control are based on barge loading ⁽⁵⁾

Chemical	Annual Loading Rate (gal/yr)	Saturation Factor ⁽⁶⁾	Vapor Pressure (psi) ⁽⁷⁾	Vapor MW (lb/lb-mol)	Temp (°F)	Loading Loss (lb/10 ³ gal) ⁽⁸⁾	Annual Vapors Routed MVCU (tpy)	Heat Content (BTU/lb)	Heat Released (MMBtu/yr) ⁽⁹⁾
Naphtha	600,844,020	0.50	3.86	69.00	73.50	3.11	934.47	20,669	38,629
Jet Fuel	528,026,520	0.50	0.01	130.00	73.50	0.02	4.97	21,269	212
Diesel	140,330,820	0.50	0.01	130.00	73.50	0.02	1.07	19,594	42
Gas Oil	507,974,880	0.50	0.01	130.00	73.50	0.02	3.86	18,147	140

Hourly Vapors to Control are Based on Ship loading ⁽⁵⁾

Chemical	Hourly Loading Rate (gal/hr)	Saturation Factor ⁽⁶⁾	Vapor Pressure (psi) ⁽⁷⁾	Vapor MW (lb/lb-mol)	Temp (°F)	Loading Loss (lb/10 ³ gal) ⁽⁸⁾	Hourly Vapors Routed MVCU (lb/hr)	Heat Content (BTU/lb)	Heat Released (MMBtu/hr) ⁽⁹⁾
Naphtha	1,260,000	0.20	3.86	69.00	73.50	1.24	1,567.70	20,669	32.40
Jet Fuel	1,260,000	0.20	0.01	130.00	73.50	0.01	9.49	21,269	0.20
Diesel	1,260,000	0.20	0.01	130.00	73.50	0.01	7.66	19,594	0.15
Gas Oil	1,260,000	0.20	0.01	130.00	73.50	0.01	7.66	18,147	0.14

**Table D-6
Vapor Combustion Units (MVCU) - Potential Emissions
CCI Corpus Christi LLC**

Emission Factors for Loading Material

CO ₂ Emission Factor for Naptha ⁽⁴⁾ =	68.02 kg CO ₂ /MMBtu	CH ₄ Emission Factor for all ⁽⁴⁾ =	0.003 kg CH ₄ /MMBtu
CO ₂ Emission Factor for Jet Fuel ⁽⁴⁾ =	72.22 kg CO ₂ /MMBtu	N ₂ O Emission Factor for all ⁽⁴⁾ =	0.0006 kg N ₂ O/MMBtu
CO ₂ Emission Factor for Diesel ⁽⁴⁾ =	73.96 kg CO ₂ /MMBtu		
CO ₂ Emission Factor for Gas Oil ⁽⁴⁾ =	75.10 kg CO ₂ /MMBtu		

Controlled Loading Emissions

Emission Source	Chemical	CO ₂ Emissions		CH ₄ Emissions		N ₂ O Emissions		CO ₂ e Emissions ⁽³⁾	
		lb/hr ⁽¹⁰⁾	TPY ⁽¹¹⁾	lb/hr ⁽¹⁰⁾	TPY ⁽¹¹⁾	lb/hr ⁽¹⁰⁾	TPY ⁽¹¹⁾	lb/hr ⁽¹⁰⁾	TPY ⁽¹¹⁾
MVCU	Naphtha	4,860	2,897	0.21	0.13	0.04	0.03	4,878	2,907
	Jet Fuel	32	17	<0.01	<0.01	<0.01	<0.01	32	17
	Diesel	24	3	0.00	<0.01	0.00	<0.01	25	3
	Gas Oil	23	12	<0.01	<0.01	<0.01	<0.01	23	12
Total		4,940	2,929	0.22	0.13	0.04	0.03	4,958	2,939

Notes:

- (1) Emission factors are based on 40 CFR Part 98 Subpart C, Table C-1 and Table C-2 for natural gas.
- (2) Global warming potential factors are based on 40 CFR Part 98 Subpart A, Table A-1.
- (3) CO₂e emissions are based on the sum of the CO₂, CH₄, and N₂O emissions times their respective GWP factors.
- (4) Loading material emission factor is based on 40 CFR Part 98 Subpart C, Table C-1 and C-2.
- (5) Annual: Since barge loading has a higher saturation factor, annual emissions are based on barge loading, conservatively under the assumption that all vapors are routed to the MVCU.
Hourly: The pumping capacity of ship loading is six times greater than that of barge loading, therefore, the hourly emissions are based on ship loading with the conservative assumption that all vapors are routed to the MVCU.
- (6) Saturation factor for barge and ship loading is 0.5 and 0.2 respectively (AP-42 Section 5.2-1)
- (7) Vapor pressures are based on Tanks 4.0.9d runs for annual and hourly. Annual vapor pressures are average and hourly vapor pressures are maximum.
- (8) Loading loss is calculated based on AP-42 Chapter 5.2, Equation 1.
- (9) Heat released for each chemical is calculated using the heat content (btu/lb) and the calculated vapors routed to the MVCU.
- (10) Hourly emissions are based on emission factor * heat released (MMBtu/hr) * 2.204 lb/kg
- (11) Annual emissions are based on the emission factor * Heat released (MMBtu/yr) * 2.204 lb/kg / 2000 lb/ton

**Table D-7
Fugitive Equipment Components - Potential Emissions
CCI Corpus Christi LLC**

Component Type and Service	Estimated Number of New Components	USEPA SO2MI w/out C2 Emission Factor ⁽¹⁾ (lb/hr-component)	Control Efficiency ⁽²⁾ (percent)	Calculated Emission Rates ⁽³⁾		
				lb/hour	tpy	
Valves						
Gas/Vapor	682	0.0089	97	0.18	0.80	
Light Liquid	2,572	0.0035	97	0.27	1.18	
Heavy liquid	642	0.0007	0	0.45	1.97	
Pumps						
Light Liquid	46	0.0386	85	0.27	1.17	
Heavy liquid	11	0.0161	0	0.18	0.78	
Flanges/Connectors						
Gas/Vapor	1,202	0.0029	30	2.44	10.69	
Light Liquid	3,631	0.0005	30	1.27	5.57	
Heavy liquid	908	0.00007	30	0.04	0.19	
Relief Valves						
Gas Vapor	39	0.2293	97	0.27	1.18	
Compressors						
Gas Vapor	2	0.5027	85	0.15	0.66	
				Total Emissions	5.52	24.18
				Total CH₄ ⁽⁴⁾	1.10	4.84
				Total CO₂e ⁽⁵⁾	23.18	101.54

Notes:

- (1) Air Permit Technical Guidance Package for Chemical Sources - Equipment Leak Fugitives. TCEQ. (October 2000).
- (2) Control efficiencies based on TCEQ Leak Detection and Repair Program 28VHP. Relief valves are routed to the flare for control.
- (3) Sample Calculations - Fugitive Emissions (Light Liquid Pumps)

$$\text{lb VOC / hr} = 46 \text{ heavy liquid valves} * 0.0386 \text{ lb VOC / hr / component} * (100\% - 85\%) = 0.27 \text{ lb VOC/hr}$$

$$\text{tons VOC / yr} = 0.27 \text{ lb VOC / hr} * 8760 \text{ hr /yr} / 2000 \text{ lb/ton} = 1.17 \text{ tons VOC/yr}$$
- (4) Piping components are assumed to consist 20% methane.
- (5) Global warming potential factor for CH₄ is 21 as indicated on 40 CFR Part 98 Subpart A, Table A-1.

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