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28 April 2014

Mr. Todd Robert
U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202

RE: Response to 27 March 2014 CCI Corpus Christi Condensate Splitter and Bulk Terminal Application Information Request
CCI Corpus Christi LLC - Corpus Christi, Texas

Dear Mr. Robert:

This letter is in response to your email requesting technical information for the CCI Corpus Christi LLC (CCI) Condensate Splitter Facility located in Corpus Christi dated 27 March 2014. On behalf of CCI, Weston Solutions, Inc. (WESTON®) submits the following response to EPA's individual requests. **Attachment 1** of this response includes all of Section 3 and 4 of the PSD permit application and **Attachment 2** includes the revised tables in Appendix D. Table 1(a) and 2F have also been revised and are provided at the end of **Attachment 2.**

If you have any questions regarding this submittal, please contact me at (512) 651-7118 or via email at Lon.Morris@westonsolutions.com.

Very truly yours,
WESTON SOLUTIONS, INC.

Lon Morris

Lon Morris
Project Manager

cc: Leann Plagens, CCI Corpus Christi LLC

Response to 27 March 2014 CCI Corpus Christi Condensate Splitter and Bulk Terminal Application Information Request

EPA Question 1 – On page 3-1, Section 3-2, Auxiliary Boilers
Please verify reference to EPNs H-1 and H-2, should be Bl-1 and Bl-2, or expand on the discussion in this paragraph to explain the reference.

> **CCI Response** – Page 3-1 has been revised to correct EPNs H-1 and H-2 to BL-1 and BL-2. Please see revised page in **Attachment 1**.

EPA Question 2 – On page 3-2, Fugitive Components
How were fuel gas and natural gas components addressed in deriving estimated fugitive emissions from the project? Was the use of an Audio/Visual/Olfactory inspection program to control these emissions considered?

> **CCI Response** – The component counts provided in Table D-7 are site-wide counts including fuel gas and natural gas components. Emissions have been revised to assume that all gas/vapor components will be in methane service, the revised Table D-7 is provided in **Attachment 2**. Section 3.4 has also been revised to represent the new calculation methodology. An AVO program was not considered for fugitive components. We have represented the TCEQ sanctioned 28VHP LDAR program for all fugitive components.

EPA Question 3 – On page 3-3, Section 3-6 Emergency Generator and Firewater Pump Engines
Is there a testing schedule proposed to affirm operability of the engines throughout the year? Is the schedule in line and consistent with vendors instruction? Are 100 hours per year in operation an exaggerated or minimized estimate?

> **CCI Response** – The emergency generator and firewater pump engines will be tested in accordance with vendor instructions. Typical vendor packages recommend weekly test runs for 15-20 minutes equating to less than 20 hours per year. Emissions are conservatively based on 100 hours per year.

EPA Question 4 – On Page 4-1, Section 4
Potential Emissions from the following sources were not addressed. Please explain, in detail, the potential for GHG emissions (including combusted VOC emissions) from each of these sources.

- The Jet Fuel Treater

  CCI Response – There are no potential air emissions from the jet fuel treater. The jet fuel treater consists of caustic scrubbing, water wash, salt drying, clay treating, and filtration, the treated jet fuel is then routed to fixed roof storage tanks TK-107 through TK-108.

- the Cooling Tower (estimated VOC fugitive emissions)

  CCI Response – Cooling tower emissions have been added, it is conservatively assumed that all the VOC in the cooling tower is methane. Emission calculations are provided in Table D-10. The emission calculation methodology is provided in Sections 3.8 and the BACT discussion is provided in Section 4.8

- the Feed Preheater

  CCI Response – The feed preheater in Figure 2-1 is not a combustion source; this is a series of heat exchangers.

- Filling / working losses from the Vertical Fixed Roof storage tanks (flared, combusted, vapor balanced?

  CCI Response – Jet fuel, diesel and gas oil are the only products stored in vertical fixed roof tanks and will not be routed to a control device since all three materials have vapor pressures less than 0.5 psia. The methane content in jet fuel, diesel, and gas oil is less than 0.5 volume percent in the vapor-phase. According to 40 CFR 98.253(n) we can assume zero methane emissions.

- Wastewater generated at the site (potential light end VOC emissions)

  CCI Response – Wastewater treatment emissions have been added, it is conservatively assumed that all the VOC emissions are methane. Emission calculations are provided in Table D-11. The emission calculation methodology is provided in Section 3.9, and the BACT discussion is provided in Section 4.9.

- Truck Loading operations

  CCI Response – Jet fuel, diesel, and gas oil will be loaded by trucks and will not be routed to a control device since all three materials have vapor pressures less than 0.5 psia. The methane content in jet fuel, diesel, and gas oil is less than 0.5 volume percent in the vapor-phase. According to 40 CFR 98.253(n) we can assume zero methane emissions. Y-grade product may also be loaded by truck in a dedicated truck spot. The Y-grade product has a vapor pressure above atmospheric pressure and will be stored in pressurized spheres with no venting to atmosphere. The Y-grade in the pressurized spheres can evaporate or condense as the liquid level in the spheres changes, or due to atmospheric conditions, without the necessity of venting. There are no emissions from loading Y-grade product.

EPA Question 5 – On page 4-1, Section 4.1 Plant-Wide Sources
Under the CCS discussion, please provide the expected CO_2 concentration on the exhaust stream, and reconsider the technical feasibility conclusion with that information in mind.

> **CCI Response** – Section 4.1 has been revised to address the technical feasibility of CCS. Revised Section 4-1 is provided in **Attachment 1**.

EPA Question 6 – On page 4-4, Section 4.1 Plant-Wide Sources

> Please expand on the CCS economic viability discussion, providing a detailed cost analysis to support the conclusion that CCS in not economically feasible.

> **CCI Response** – Section 4.1 has been revised to address the economic feasibility of CCS. Revised Section 4-1 is provided in **Attachment 1**.

EPA Question 7 – On page 4-9, Section 4.4, Flare
Flare Gas Recovery as a control option for this facility was not addressed. Please include this control option in your analysis and make a case for technical and economic feasibility.

> **CCI Response** – Section 4.4 of the BACT has been revised to include flare gas recovery as an option; however, this option is eliminated as technically infeasible. Please see the revised Section 4.4 in **Attachment 1**.

EPA Question 8 – On page 4-12, Section 4.5, Marine Vapor Control, Step 1
Vapor balancing for loading emissions is not addressed as a potential control option
Please explain why this is not appropriate for this site or address it as a potential control.

> **CCI Response** – Vapor balancing is not a technically feasible option for control of vapors associated with marine loading. In many cases the contents of the vapor space of an inbound marine vessel is unknown. Potential contaminants would be retained in the marine vessel if a vapor balance system is utilized and would threaten loaded product integrity. In addition, the marine vessel would need to be specially designed for a vapor balance system. Currently there are no regulations requiring that marine vessels be equipped with vapor balance capabilities. This would place unwarranted limitations on the type of marine vessels for product loading.

EPA Question 9 – On page 4-12, Section 4.5, Marine Vapor Control, Step 3
The last sentence of the Step 3 discussion indicates thermocouples, in this situation, will cause unnecessary combustion of fuel gas. Is this conclusion appropriate to your design?

> **CCI Response** – This was an error, it should have been "ensuring that excess fuel is **not** unnecessarily combusted." This sentence has been removed since it does not add any value to the discussion and is repetitive. Revised Section 4.5 is provided in **Attachment 1**.

EPA Question 10 – On page 4-15 and 4-16, Section 4-6, Fugitives
The discussion on use of leakless technologies to control fugitive emissions indicates this is an inappropriate option based on creation of collateral emissions due to maintenance activities, as well as not an economically feasible option. Please justify this conclusion with a detailed analysis demonstrating the amount of collateral emissions expected and a detailed cost analysis that shows the cost per ton of controlled emissions.

> **CCI Response** – Leakless technology, while the most effective of the control technologies, has not been adopted as Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) for any projects with GHG emissions from fugitive components. Additionally, leakless technology is not required to control fugitive emissions of toxic or hazardous air pollutants (HAPs) under Federal Rules. Therefore, it is not reasonable to install leakless components for the control of methane, which has no known hazardous impacts.

EPA Question 11 – In Table D-3 Flare operations
Under section B a molecular weight (MW) of 17.66 is given for the combined gas stream. Under Section C, 1 a MW of 17.62 is used in the values and calculations section. Please explain the difference between the two values and how any adjustment would impact the projected emissions from the facility.

> **CCI Response** – The 17.62 lb/lb-mol is based on actual heat and material balance of streams provided by Willbros Engineers, LLC (Willbros). The molecular weight of 17.66 lb/lb-mol is calculated based on the MW of each constituent and the volume percent. The emissions should have been based on 17.66 lb/lb-mol and have been revised to reflect the change. The heat content of combined gas has also been revised; it is now calculated based on the heat content of each constituent and its volume %. Revised Table D-3 is provided in **Attachment 2** of this letter. Table D-1, Summary of Potential to Emit, has also been revised due to this change and is provided in **Attachment 2**.

EPA Question 12 – In Tables D-3 and D-4, Flaring Operations
Under Table D-3 Section B and Table D-4, a detailed gas composition is provided. Please explain the source of this analysis and its justification. (i.e. Process knowledge, historic natural gas composition in the area, etc.)

> **CCI Response** – Gas compositions provided in Tables D-3 and D-4 are based on process simulations performed by Willbros. The volumetric flow rate to the flare during MSS was previously based on 30% of the total flare capacity due to lack of information. However, with more knowledge of the design, the volumetric flow rate of gases to the flare during MSS has been recalculated and has been revised to 70,000 scf/hr. Table D-4 is updated to reflect this change and is provided in **Attachment 2.** The 70,000 scf/hr is based on the summation of volumetric flows during MSS activities.

EPA Question 13 – Table D-5 Equipment Clearing
Please explain on how the "Total Equipment Volume" values were derived.

> **CCI Response** – Emissions from equipment clearing are routed to the flare for control. The equipment volumes were calculated based on the diameter and height of each piece of equipment. The table below provides a list of equipment, service material, and volume.

Equipment	Equipment ID	Material Service	Volume (ft^3)
340-C1 and 350-C1	Condensate Splitters	Condensate	29,575.15
340-C2 and 350-C2	Jet Fuel Strippers	Jet Fuel	811.12
340-C3 and 350-C3	Light Naphtha Stabilizers	Naphtha	2,401.55
340-C4 and 350-C4	Naphtha Strippers	Naphtha	811.12
340-C5 and 350-C5	Diesel Strippers	Diesel	811.12
340-V1 and 350-V1	Condensate Preflash Drums	Condensate	6,785.84
340-V2 and 350-V2	Condensate Splitter Overhead Accumulators	Condensate	1,910.09
370-V5	Jet Fuel Caustic Treater	Jet Fuel	2,389.18
370-V6	Jet Fuel Water Wash	Jet Fuel	1,425.50
370-V7 A/B	Jet fuel Coalescers	Jet Fuel	353.43
370-V8 A/B	Jet Fuel Salt Driers	Jet Fuel	5,387.83
370-V9 A/B	Jet Fuel Clay Treaters	Jet Fuel	5,387.83

340-V11 and 350-V11	Naphtha stabilizer ovhd accumulator	Naphtha	791.68
330-V3	Flare Knockout Drum	Condensate, Jet Fuel, Naphtha, Diesel, and Gas Oil	862.05
260-V4	Fuel Gas Knockout Drum	Condensate, Jet Fuel, Naphtha, Diesel, and Gas Oil	47.12

Annual volume of vapors routed to the flare for each material is based on total volume of equipment servicing that material. Hourly volume of vapors routed to the flare for each material is conservatively based on assuming the largest piece of equipment will be cleared in an hour.

Volume from the flare knockout drum was previously excluded from the total volumes. Table D-5 has been revised to include the volume from the fare knockout drum. Revised Table D-5 is provided in **Attachment 2.**

EPA Question 14 – Table D-6 Temporary Control Device Emissions
How were the Events per year (and duration) assumptions derived?

CCI Response – Number of events per year is based on cleaning one floating roof tank and two fixed roof tanks, this is a conservative assumption and CCI will never clean more than three tanks in a year. Based on historic degassing events for large tanks, 8 hours is very conservative, most degassing events will not exceed 8 hours. Duration of vacuum truck events is also based on historic events.

EPA Question 15 – In Table D-7 Fugitive Equipment components – Potential emissions
Does the component count include the fuel gas system?

CCI Response – The component counts provided in Table D-7 are site-wide counts. Emissions have been revised based on the conservative assumption that the component counts in gas/vapor service are 100% methane. The revised Table D-7 is provided in **Attachment 2**.

EPA Question 16 – Table D-8 Marine Vapor combustor, Section D
Please clarify the meaning of Note (3) “Annual and hourly vapor pressures are based on Tank 4.0.9d runs”

CCI Response – The vapor pressure of naphtha and condensate will increase with temperature; the vapor pressures were calculated at 73.50°F and 95.00°F using the EPA’s Tanks 4.0.9d software. The Tanks 4.0.9d software was used to determine VOC emissions and were submitted with the TCEQ application. However, since there are no GHG emissions from tanks, the Tanks output files are not necessary and the only information used from the Tanks program were the vapor pressures at 73.50°F and 95°F.

EPA Question 17 – What are the design ratings for the heaters and boilers? What are their maximum and normal firing rates?

> **CCI Response** – The maximum firing rates for the boilers and heaters are conservatively assumed to equal the design firing rates. The normal/average firing rate for the heaters (H-1 and H-2) were assumed to be about 90% of the maximum firing rate. The normal/average firing rate for the boilers (BL-1 and BL-2) were based on the design knowledge provided by Willbros. The normal/average firing rate for the boilers is approximately 88% of the maximum firing rate.

EPA Question 18 – How will CCI address potential GHG emissions from SF6 circuit breakers at the new facility? Does CCI intend to use vacuum breakers?

> **CCI Response** – CCI is not anticipating the use SF_6 vacuum breakers.

EPA Question 19 – Does the 500,000 bbl/day loading capacity represent a cap on future production capacity?

> **CCI Response –** No, the 500,000 bbl/day is part of Phase II and will not be processed. In Phase II CCI is requesting authorization of storage and loading of 500,000 bbl/day of condensate/crude.

EPA Question 20 – When the cooling tower is in operation, does the facility expect to employ an intermediate closed loop medium for heat transfer? Is there a potential for light end VOCs to be lost to the system through the cooling water?

> **CCI Response –** There is potential of VOC in the cooling water; it is conservatively assumed that the VOC content in the water will be 0.7 lb/MMGal. GHG emissions from the cooling tower have been added to the emission calculations and are provided in Table D-10. The emission calculation methodology is provided in Section 3.8, and the BACT discussion is provided in Section 4.8.

EPA Question 21 – This question is based on a phone call between Lon Morris and Robert Todd on April 15 2014. Todd asked for clarification in regards to Step 3 “Rank remaining control technologies based on control effectiveness” as part of our BACT analysis for fuel selection and requested clarification on the 40% overall control efficiency.

> **CCI Response –** The 40% is based on CO_2 emission factor for natural gas (53.02 kg CO_2/mmBtu) and the average emission factor of all petroleum products (distillate fuel oil No.1, distillate fuel oil No.2, distillate fuel oil No.4, residual fuel oil no.5 and residual fuel oil No.6). The average emission factor for the listed fuels is 74.06 kg CO_2/mmBtu. (74.06 – 53.02)/53.02 x 100 = 39.7% which was rounded to 40%.

ATTACHMENT 1
REVISED SECTIONS OF PERMIT APPLICATION

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 (CO_2e) basis. The CO_2e 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 (CO_2), methane (CH_4), and nitrous oxide (N_2O). CCI does not expect emissions of hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), or sulfur hexafluoride (SF_6) 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 CSFP will utilize two fuel gas fired heaters (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 fuel gas 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 AUXILARY BOILER

The new CSFP will utilize two fuel gas fired boilers (EPNS BL-1 and BL-2). GHG emissions from the boiler were calculated using the proposed maximum hourly and average annual firing rates and GHG emission factors for fuel gas 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 CH_4 and small amounts of CO_2 and N_2O 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 CO_2 emissions were based on the factor from U.S. EPA's AP-42 Table 1.4-2 (July 1998). The CH_4 and N_2O 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 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. GHG emissions were based on 100% methane content for all components in gas/vapor service. Detailed GHG emission calculations for fugitive components are provided in **Table D-7** 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), CO_2 emission factors derived from U.S. EPA's AP-42 Table 1.4-2 (September 1998) and CH_4/N_2O 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-8** located in **Appendix D**.

3.6 EMERGENCY GENERATOR AND FIREWATER PUMP ENGINES

There will be one emergency generator (EPN EMGEN) and two firewater pumps (EPNs FW-1 and FW-2). GHG emissions from these sources were calculated using the proposed maximum hourly and average annual firing rates and GHG emission factors for distillate fuel oil no. 2 from 40 CFR Part 98, Subpart C, Tables C-1 and C-2. Detailed GHG emission calculations are provided in **Table D-9** 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;
- Clearing of process vessels and equipment;
- Storage tanks degassing; and
- Vacuum trucks.

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 CSFPP 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 CSFP. Detailed GHG emission calculations from MSS are provided in **Table D-4** located in **Appendix D**.

3.7.3 Clearing of Process Vessels and Equipment

GHG emissions will be generated from the clearing of process vessels and equipment. Emissions from equipment clearing will be routed to the flare for control. GHG flare emissions from equipment clearing were calculated based on the calculated heat input to the flare for each material and the corresponding CO_2, CH_4, and N_2O emission factors from 40 CFR Part 98 Subpart C, Table C-1 and C-2. Detailed GHG emission calculations from equipment clearing are provided in **Table D-5** located in **Appendix D**.

3.7.4 Tank Degassing and Vacuum Trucks

GHG emissions will be generated from tank maintenance. Tanks are emptied to the extent possible using vacuum trucks before opening the tank to the atmosphere. Emissions from vacuum tucks and tank degassing are routed to a regenerative thermal oxidizer (RTO) for control. The GHG emissions from the RTO are based on the duration of each event and the mass of material routed to the RTO. Detailed GHG emission calculations from the RTO are provided in **Table D-6** located in **Appendix D**.

3.8 COOLING TOWER

Methane emissions from the process cooling water tower (EPN CWT) were calculated using the cooling water recirculation rate and the controlled emission factor for cooling towers in EPA's AP-42 Chapter 5.1.1, Table 5.1-2 (January 1995). GHG emissions were calculated based on the conservative assumption that 100% of the VOC emissions are methane. Detailed GHG emissions from the cooling tower are provided in **Table D-10** located in **Appendix D**.

3.9 WASTEWATER SYSTEM EMISSIONS

The process wastewater gathering and treatment system will emit VOCs to the atmosphere (EPN: FUG-WWTP). These wastewater system emissions were estimated using the EPA's WATER9, Version 3.0 software, which is the most widely accepted method for estimating emission rates from industrial wastewater treatment systems. Separate WATER9 models were developed to represent typical operations (for establishing potential annual emissions) and to represent maximum hourly emission rates. GHG emissions were calculated based on the conservative assumption that 100% of the VOC emissions are methane. Detailed GHG emissions from the process wastewater gathering and treatment system are provided in **Table D-11** located in **Appendix D**.

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 CO_2, CH_4, and N_2O and addressed as CO_2e 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; and
- Emergency Equipment

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

<u>Carbon Dioxide Capture and Sequestration (CCS):</u> CCS technologies involve the separation, collection, and compression of CO_2 gas from point source emissions, transportation of the compressed CO_2 gas to an on-site or off-site storage facility, and sequestering of the CO_2 in a viable storage facility.

The proposed CSFP will emit CO_2 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 CO_2-emitting stacks, such as the process heaters, the auxiliary boilers, and the marine vapor control unit. The capture of the CO_2 gas emissions would require separation of the CO_2 gas from the combined combustion exhaust flows using a CO_2 separation process.

The proposed facility will not have on-site CO_2 storage. Therefore, any CO_2 captured and compressed would need to be transported off-site via a third party CO_2 pipeline system. The United States already presently has more than 3,000 miles of CO_2 pipelines used to transport CO_2 for Enhanced Oil Recovery (EOR).

Captured, compressed, and transported CO_2 may be stored or sequestered by means of currently available methods, including storage in geologic formations, EOR, and injection of CO_2 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 CO_2 in a variety of geological formations and regions across the United States. Because CO_2 storage is still an emerging technology, regulations and standards have not been developed.

Step 2 – Elimination of Technically Infeasible Options

The EPA considers CCS as an add-on pollution control technology available for facilities emitting CO_2 in large amounts such as fossil fuel-fired power plants and facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas process, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). The EPA generally considers a technology to be technically feasible if it: (1) has been demonstrated and operated successfully on the same type of source under review, or (2) is available and applicable to the source type under review. CO_2 capture technologies, including post-combustion capture have not been demonstrated in practice on charge heaters used in crude/condensate fractionation processes. A search of the EPA RBLC database revealed no facilities listed as using CCS for BACT.

The expected concentration of CO_2 in the source exhaust stream is conservatively estimated to be as high as 9% by volume. Although CO_2 capture technologies may be commercially available, there is currently insufficient evidence to support that CO_2 capture is applicable to sources with low concentration CO_2 streams such as condensate splitters. The process of CO_2 capture concentrates the CO_2 stream so it can be transported and/or stored. To date, successful CCS implementation has only involved highly concentrated CO_2 streams for practical and economic reasons. The CO_2 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 CO_2 (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 CO_2 stream requires large compression equipment, capable of acidic gas handling (since CO_2 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. As such, CCS should be considered as technically infeasible for the condensate splitter and eliminated as BACT.

Step 3 – Ranking of Remaining Technologies Based on Control Effectiveness

The economic reasonableness assessment is based on a 90% capture efficiency of the following CO_2-emitting sources at the site:

- Two Charge Heaters (EPNs: H-1 and H-2);
- Auxiliary Boilers (EPNs: BL-1 and BL-2); and
- Marine Vapor Control Unit (EPN: MVCU)

These sources contribute more than 95% of the total CO_2e emissions. A CCS system for these sources would be the most effective method of controlling site-wide CO_2 emissions, however CCS is not considered a technically feasible control option for these sources as demonstrated in Step 2

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

Although CCS is demonstrated to be technically infeasible in Step 2, further evidence supports the conclusion that CCS is also economically unviable. Theoretically, post-combustion capture of CO_2 from heater and boiler exhaust streams can be absorbed in an amine solvent, concentrated in the amine regenerator vent stream, dried, compressed and transported via pipeline for EOR or storage in geologic formations. Based on 90% capture efficiency, CCS could reduce CO_2 emissions from the charge heaters, auxiliary boilers, and the marine vapor combustor unit up to 22,231 tons per year. The additional process equipment required to separate, cool, and compress the CO_2 would require significant additional energy expenditure. The results of the cost of construction and operation of the CCS are presented in **Table 4-1**.

Table 4-1
Approximate Cost of Construction/Operation of Post-Combustion CCS System

CCS System Component	Cost ($/ton of CO_2 Controlled)	Tons of CO_2 Controlled/year	Total Annual Cost
Capture and Compression of CO_2	$104.72	200,079.38	$20,952,012.73
Transport of the Captured CO_2	$1.10	200,079.38	$220,547.50
Storage of CO_2	$6.61	200,079.38	$1,323,285.01
Total CCS system Cost	**$112.43**	**-**	**$22,495,845.24**

The cost in dollars per ton of CO_2 is based on the Report of the Interagency Task Force on Carbon Capture (August, 2010). This report provides a range of costs for transport and storage facilities; the lower end of the range was conservatively used in this CCS cost analysis. Cost of transport of the captured CO_2 is estimated to be \$1 to \$3 per tonne per 100 km of pipeline. It is conservatively assumed that a suitable pipeline is within 100 km. Total tons of CO_2 captured is based on 90% capture of all CO_2 emissions from the charge heaters, auxiliary boilers, and the marine vapor combustor unit. It is estimated that the capture, transport, and storage of the CO_2 will cost approximately \$22,495,845 per year. The total cost indicates that the CCS is not an economically viable option for this project. 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

<u>Energy Efficiency Design Technologies</u>

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

1. <u>Efficient Burner Design:</u> 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. <u>Increased Heat Transfer:</u> 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. <u>Air Preheat System:</u> 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. <u>Heat Recovery System:</u> 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. <u>Product Heat Recovery:</u> 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 4-2**.

Table 4-2
Process Heater BACT Control Efficiency

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 4-2** 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 4-3
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 boilers (EPNs: BL-1 and BL-2) is the combination of all the BACT options listed in Step 1.

4.4 PROCESS FLARE

GHG emissions, primarily CO_2, 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. CO_2e 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. Flare Gas Recovery: Installation and operation of a flare gas recovery system reduces GHG combustion emissions by routing flared gases back to the fuel gas system. *(Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Flares, November 2010).*
2. 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.
3. 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 CO_2 emissions. *(Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Flares, November 2010).*
4. 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. The same technical and safety constraints apply to the use of a VRU as an alternative control device to the flare.

A flare gas recovery system would be technically infeasible due to the very low volume of gas sent to the flare on a continuous basis, therefore, it is not practical to route that stream back to process as fuel gas.

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 4-4
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 4-4** 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 CSFP will be a new source and will be able to incorporate the most current technology into the design. 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 consists of a combination of the options listed in **Table 4-4**, 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 eliminated 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.

CO_2 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 will continuously monitor the temperature and allow instantaneous adjustments to the required natural gas fuel supply. This will maintain an adequate combustion chamber temperature for proper VOC destruction.

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 405.11 tpy, which is a negligible amount compared 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 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 CSFP 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

Step 1 – Identification of Potential Control Technologies

As detailed below, there are several energy efficiency technologies and best practices that can be incorporated into the design and operation of the emergency generator and firewater pump engines:

1. <u>Vendor-Certified Tier 4 and Clean Burn Engine</u>: The U.S. EPA has set stringent emission standards for non-road diesel engines in accordance with 40 CFR Part 60, Subpart IIII. Compliance with these standards will result in lower potential GHG emissions.
2. <u>Fuel Selection</u>: 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."
3. <u>Operation Restriction</u>: Dedication to emergency service will limit the total hours of operation as well as GHG emissions. Operating hours can be monitored with the use of a run-time meter in conjunction with administrative controls to reduce engine use.

Step 2 – Elimination of Technically Infeasible Options

During emergency conditions, non-volatile fuel (such as diesel or other heavy oils) is required to be used and readily available. Natural gas or other gaseous fuels would not be available during certain emergency events; therefore, these lower carbon fuels are not technically feasible options for emergency engines. All remaining 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 Control Technologies Based on Control Effectiveness

The control technologies specified in Step 1 above are all top-ranked control technologies for emergency engines, with the exception of low carbon fuel selection. The use of one technology or practice does not preclude the use of any other control technology or practice, and the combination of control technologies and practices will result in higher energy efficiency than any one.

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

Except for low carbon fuel selection, all the aforementioned control technologies are considered economically reasonable. These listed potential control technologies will not result in any adverse environmental impacts.

Step 5 – Selection of BACT

CCI proposes that BACT for the emergency generator engine and the firewater pump engines is the combination of all the BACT options listed in Step 1, with the exception of low carbon fuel selection.

4.8 COOLING TOWER

Step 1 – Identification of Potential Control Technologies

Following is a list of control technologies that minimize GHG emissions from the cooling tower.

1. Air Cooling System: An air-cooling system (e.g, fin fans) would eliminate GHG emissions from the plant cooling process.
2. Cooling Water Tower Monitoring and Repair Program: Implementation of a leak-detection program reduces GHG emissions by detecting and subsequently repairing leaks in the cooling water system.

Step 2 – Elimination of Technically Infeasible Options

Exclusive use of an air cooling system is technically infeasible; the ambient dry bulb temperature will typically be too high in Corpus Christi, Texas to cool some process equipment and piping to the required temperature. Therefore, this control technology by itself will not be considered any further in the BACT analysis. The cooling water tower monitoring and repair program identified in Step 1 is considered technically feasible and therefore needs to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Ranking of Remaining Control Technologies Based on Control Effectiveness

Implementation of a cooling water tower LDAR program reduces emissions from the cooling tower by almost 90% based on comparison of the uncontrolled cooling water VOC emission factor and the controlled cooling water tower emission factor from EPA's AP-42 Chapter 5.1.1, Table 5.1-2 (January 1995).

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

There are no negative economic, energy, or environmental impacts associated with the cooling water tower LDAR program.

Step 5 – Selection of BACT

CCI proposes that BACT for the cooling tower is implementation of a structured cooling water tower LDAR program. The program will be based on the monitoring and repair requirements specified in 40 CFR Part 63, Subpart F. In order to detect GHG emissions, total organic compounds will be monitored in lieu of HAPs.

4.9 WASTEWATER TREATMENT PLANT

The CSFP wastewater treatment plant removes volatiles and cleans the water before discharge to the Neches River. The proposed design of the wastewater system minimizes any VOC emissions. Following are key aspects of the wastewater design that establish BACT:

- All process wastewater sewers will be enclosed (e.g., no trenches or other open conveyance).
- Each process drain will be equipped with a water seal, cap, or plug as appropriate based on the intended nature and frequency of use for each drain.
- Manholes, lift stations, and other junction boxes will be equipped with sealed covers, and any associated vent pipes will be designed consistent with 40 CFR Part 63 Subpart G standards.
- The oil-water separator will be enclosed, and the enclosure vent will be routed to an activated carbon system with two carbon canisters in series.
- All other pre-treatment units will be enclosed, such that the first unenclosed treatment unit to receive process wastewater will be aerobic biological treatment tanks.

ATTACHMENT 2
REVISED EMISSIONS CALCULATIONS

Table D-1 (Revised April 2014)
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_2O	CO_2e	
Charge Heater (H-1)	78,271.36	1.33	0.13	78,344.06	D-2
Charge Heater (H-2)	78,271.36	1.33	0.13	78,344.06	D-2
Boiler (BL-1)	18,372.50	0.31	0.03	18,389.56	D-2
Boiler (BL-2)	18,372.50	0.31	0.03	18,389.56	D-2
Flare (FL-1)	2,165.26	5.99	<0.01	2,316.36	D-3
Flare-MSS (FL-MSS)	368.11	0.04	<0.01	369.29	D-4 & D-5
Temporary Control Device (TK-MSS)	36.88	<0.01	<0.01	37.01	D-6
Fugitives (FUGS)	-	15.92	-	397.99	D-7
Marine Vapor Combustion Unit (MVCU)	29,022.70	1.12	0.22	29,116.27	D-8
Emergency Generator (EMGEN)	122.31	<0.01	<0.01	122.73	D-9
Fire Water Pump (FW-1)	40.77	<0.01	<0.01	40.91	D-9
Fire Water Pump (FW-2)	40.77	<0.01	<0.01	40.91	D-9
Cooling Tower (CWT)	-	1.84	-	45.99	D-10
Wastewater Treatment Plant (WWTP)	-	9.04	-	226.02	D-11
Total Proposed PTE	**225,084.53**	**37.24**	**0.55**	**226,180.72**	
Major Source Threshold	NA	NA	NA	75,000	
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.

Table D-1 (Revised April 2014)
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_2O	CO_2e	
Charge Heater (H-1)	19,855.75	0.34	0.03	19,874.19	D-2
Charge Heater (H-2)	19,855.75	0.34	0.03	19,874.19	D-2
Boiler (BL-1)	4,722.06	0.08	0.01	4,726.44	D-2
Boiler (BL-2)	4,722.06	0.08	0.01	4,726.44	D-2
Flare (FL-1)	543.78	1.51	<0.01	581.73	D-3
Flare-MSS (FL-MSS)	54,262.77	4.14	0.25	54,441.98	D-4 & D-5
Temporary Control Device (TK-MSS)	8,988.73	0.36	0.07	9,019.34	D-6
Fugitives (FUGS)	-	3.63	-	90.87	D-7
Marine Vapor Combustion Unit (MVCU)	23,301.13	0.92	0.18	23,377.28	D-8
Emergency Generator (EMGEN)	2,446.23	0.10	0.02	2,454.62	D-9
Fire Water Pump (FW-1)	815.41	0.03	0.01	818.21	D-9
Fire Water Pump (FW-2)	815.41	0.03	0.01	818.21	D-9
Cooling Tower (CWT)	-	0.42	-	10.50	D-10
Wastewater Treatment Plant (WWTP)	-	4.56	-	114.06	D-11
Total Proposed PTE	140,329.07	16.54	0.62	140,928.06	

Table D-3 (Revised April 2014)
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 for natural gas
2. CO_2 Emission Rate Calculations			
CO_2 Emission Factor	F_{CO2}	116.91 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-1 for natural gas converted to lb/MMBtu
CO_2 Hourly Emission Rate	$ER_{CO2,H}$	**53.78 lb/hr**	$= F_H \times (H / 1{,}000{,}000 \text{ Btu/MMBtu}) \times F_{CO2}$
CO_2 Annual Emission Rate	$ER_{CO2,A}$	**214.17 tpy**	$= F_A \times (H / 1{,}000{,}000 \text{ Btu/MMBtu}) \times F_{CO2} / 2{,}000 \text{ lb/ton}$
3. CH_4 Emission Rate Calculations			
CH_4 Emission Factor	F_{CH4}	0.00221 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2 for natural gas converted to lb/MMBtu
CH_4 Hourly Emission Rate	$ER_{CH4,H}$	**<0.01 lb/hr**	$= F_H \times (H / 1{,}000{,}000 \text{ Btu/MMBtu}) \times F_{CH4}$
CH_4 Annual Emission Rate	$ER_{CH4,A}$	**<0.01 tpy**	$= F_A \times (H / 1{,}000{,}000 \text{ Btu/MMBtu}) \times F_{CH4} / 2{,}000 \text{ lb/ton}$
Hourly Global Warming Potential	$GWP_{CH4,H}$	0.03 lb/hr	$= ER_{CH4,\,H} * 25\ CO_2e$
Annual Global Warming P	$GWP_{CH4,\,A}$	0.10 tpy	$= ER_{CH4,\,A} * 25\ CO_2e$
4. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	0.00022 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2 for natural gas converted to lb/MMBtu
N_2O Hourly Emission Rate	$ER_{N2O,\,H}$	**<0.01 lb/hr**	$= F_H \times (H / 1{,}000{,}000 \text{ Btu/MMBtu}) \times F_{N2O}$
N_2O Annual Emission Rate	$ER_{N2O,\,A}$	**<0.01 tpy**	$= F_A \times (H / 1{,}000{,}000 \text{ Btu/MMBtu}) \times F_{N2O} / 2{,}000 \text{ lb/ton}$
Hourly Global Warming Potential	$GWP_{N2O,\,H}$	0.03 lb/hr	$= ER_{N2O,\,H} * 298\ CO_2e$
Annual Global Warming Potential	$GWP_{N2O,\,A}$	0.12 tpy	$= ER_{N2O,\,A} * 298CO_2e$
5. Total CO_2e Emission Rates			
Hourly Global Warming Potential	-	**53.84 lb/hr**	$= ER_{CO2,\,H} + GWP_{CH4,\,H} + GWP_{N2O,\,H}$
Annual Global Warming Potential	-	**214.39 tpy**	$= ER_{CO2,\,H} + GWP_{CH4,\,H} + GWP_{N2O,\,H}$

B. Combined Gas Composition (Natural Gas and Produced Gas)

Constituent	Volume %	MW (lb/lb-mol)	Mass %	Heat Content (Btu/scf)	Constituent Type	Number of Carbons
Water	0.04	18.02	0.04	0	NA	0
Methane	93.90	16.04	85.30	1012	GHG	1
Ethane	2.70	30.07	4.60	1783	NA	2
Propane	1.80	44.10	4.50	2557	VOC	3
n-Butane	1.20	58.12	3.95	3369	VOC	4
n-Pentane	0.20	72.15	0.82	4009	VOC	5
n-Hexane	0.16	86.18	0.80	4755.9	VOC	6
Total	**100.00**	**17.66**	**100.00**	**1,100.65**	-	-

Table D-3 (Revised April 2014)
Flare - Pilot and Normal Operation Emission Calculations
CCI Corpus Christi LLC

C. Normal Flare Emissions (Natural Gas and Produced Gas)

Parameter Name & Variable		Value & Units		Basis/Calculation/Notes
1. General Values and Calculations				
Hourly Vapor Volume to Flare	Q_H	3,850.00	scf/hr	Based on summation of volume to the flare
Annual Vapor Volume to Flare	Q_A	30.66	MMscf/yr	Based on summation of volume to the flare
MW of Combined Gas	MW	17.66	lb/lb-mol	Based on Volume % and MW of each constituent
Heat Content of Combined Gas	H_V	1,100.65	Btu/scf	Based on Volume % and heat content of each constituent
Hourly Vapor Mass to Flare	M_H	176.38	lb/hr	= Q_H x MW / 385 scf/lb-mol
Annual Vapor Mass to Flare	M_A	1,404,628.34	lb/year	= Q_A /1,000,000 x MW / 385 scf/lb-mol
Max. Hourly Vapor Heat Input to Flare	H_H	4.24	MMBtu/hr	= Q_H x H_V / 1,000,000
Annual Vapor Heat Input to Flare	H_A	33,745.99	MMBtu/yr	= Q_A x H_V
2. CO_2 Emission Rate Calculations				
Carbon Content	CC	0.76	-	= Σ (No. of Carbons$_i$ * 12 lb C/lb-mol C * Mass%$_i$ / MW$_i$)
CO_2 Hourly Emission Rate	$ER_{CO2,H}$	**490.00**	**lb/hr**	= 44 lb CO_2/12 lb C * M_H * CC
CO_2 Annual Emission Rate	$ER_{CO2,A}$	**1,951.09**	**tpy**	=(44 lb CO_2/12 lb C * M_A * CC) / 2000 lb/ton
3. CH_4 Emission Rate Calculations				
CH_4 Weight Percent	W_{CH4}	85.30	%	Based on stream composition
Flare DRE for CH_4	%	99	%	TCEQ Flare Guidance Document (October 2000)
CH_4 Hourly Emission Rate	$ER_{CH4, H}$	**1.50**	**lb/hr**	= W_{CH4} * M_H * (100%-DRE)
CH_4 Annual Emission Rate	$ER_{CH4, A}$	**5.99**	**tpy**	= W_{CH4} * M_A * (100%-DRE) / 2000 lb/ton
Hourly Global Warming Potential	$GWP_{CH4, H}$	37.61	lb/hr	= $ER_{CH4, H}$ * 25 CO_2e
Annual Global Warming Potential	$GWP_{CH4, A}$	149.77	tpy	= $ER_{CH4, A}$ * 25 CO_2e
4. N_2O Emission Rate Calculations				
N_2O Emission Factor	F_{N2O}	0.00022	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2
N_2O Hourly Emission Rate	$ER_{N2O, H}$	**<0.01**	**lb/hr**	= H_H * F_{N2O}
N_2O Annual Emission Rate	$ER_{N2O, A}$	**<0.01**	**tpy**	= H_A * F_{N2O} / 2000 lbs/ton
Hourly Global Warming Potential	$GWP_{N2O, H}$	0.28	lb/hr	= $ER_{N2O, H}$ * 298 CO_2e
Annual Global Warming Potential	$GWP_{N2O, A}$	1.11	tpy	= $ER_{N2O, A}$ * 298 CO_2e
5. Total CO_2e Emission Rates				
Hourly Global Warming Potential	-	**527.89**	**lb/hr**	= $ER_{CO2, H}$ + $GWP_{CH4, H}$ + $GWP_{N2O, H}$
Annual Global Warming Potential	-	**2,101.97**	**tpy**	= $ER_{CO2, A}$ + $GWP_{CH4, A}$ + $GWP_{N2O, A}$

D. Total Flare Emissions (Pilot Gas and Normal)

Pollutants	Pilot Gas Emissions		Normal Flare Emissions		Total Emissions	
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
CO_2	53.78	214.17	490.00	1,951.09	543.78	2,165.26
CH_4	<0.01	<0.01	1.50	5.99	1.51	5.99
N_2O	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
CO_2e	53.84	214.39	527.89	2,101.97	581.73	2,316.36

Table D-4 (Revised April 2014)
Flare - Startup/Shutdown Flaring MSS Emission Calculations
CCI Corpus Christi LLC

A. Gas Composition

Constituent	Volume %	MW (lb/lb-mol)	Mass %	HHV (Btu/scf)	No. of C
Water	3.57	18.02	1.21	0.00	0
Methane	10.65	16.04	3.22	1,012.00	1
Ethane	5.14	30.07	2.91	1,783.00	2
Propane	20.94	44.10	17.40	2,557.00	3
Isobutane	11.54	58.12	12.64	3,354.00	4
n-butane	20.28	58.12	22.21	3,369.00	4
Isopentane	9.53	72.15	12.95	4,001.00	5
n-pentane	7.62	72.15	10.36	4,009.00	5
Methylcyclopentane	0.34	84.16	0.54	4,501.20	6
Cyclohexane	0.36	84.16	0.57	4,481.70	6
Cyclopentane	0.79	70.10	1.04	3,763.70	5
Benzene	0.34	78.11	0.50	3,741.80	6
C6+	8.90	86.18	14.45	4,755.90	6
Total	100.00	**53.08**	**100.00**	**2,989.06**	-

Table D-4 (Revised April 2014)
Flare - Startup/Shutdown Flaring MSS Emission Calculations
CCI Corpus Christi LLC

B. MSS Flare Emissions

Parameter Name & Variable		Value & Units		Basis/Calculation/Notes
1. General Values and Calculations				
Hourly Vapor Volume to Flare	Q_H	0.07	MMscf/hr	Based on summation of volume to the flare during MSS
Fuel Heating Value	H_V	2,989.06	Btu/scf	= Σ (Volume $\%_i$ * HHV_i)
Molecular Weight	MW	53.08	lb/lb-mol	= Σ (Volume $\%_i$ * MW_i)
Flaring Frequency	FF	24.00	hours/year	Based on 3 events/year and 8 hours/event
Annual Vapor Volume to Flare	Q_A	1.68	MMscf/yr	=Q_H x FF
Hourly Vapor Mass to Flare	M_H	9,640.27	lb/hr	= Q_H x 1,000,000 x MW / 385 scf/lb-mol
Annual Vapor Mass to Flare	M_A	231,366.50	lb/year	= Q_A x 1,000,000 x MW / 385 scf/lb-mol
Max. Hourly Vapor Heat Input to Flare	H_H	209.23	MMBtu/hr	= Q_H x H_V
Annual Vapor Heat Input to Flare	H_A	5,021.61	MMBtu/yr	= Q_A x H_V
2. CO_2 Emission Rate Calculations				
Carbon Content	CC	0.81	-	= Σ (No. of Carbons_i * 12 lb C/lb-mol C * $\text{Mass}\%_i$ / MW_i)
CO_2 Hourly Emission Rate	$ER_{CO2,H}$	**28,799.28**	**lb/hr**	= 44 lb CO_2/12 lb C * M_H * CC
CO_2 Annual Emission Rate	$ER_{CO2,A}$	**345.59**	**tpy**	=(44 lb CO_2/12 lb C * M_A * CC) / 2000 lb/ton
3. CH_4 Emission Rate Calculations				
CH_4 Weight Percent	W_{CH4}	3.22	%	Based on stream composition
Flare DRE for CH_4	%	99	%	TCEQ Flare Guidance Document (October 2000)
CH_4 Hourly Emission Rate	$ER_{CH4, H}$	**3.10**	**lb/hr**	= W_{CH4} * M_H * (100%-DRE)
CH_4 Annual Emission Rate	$ER_{CH4, A}$	**0.04**	**tpy**	= W_{CH4} * M_A * (100%-DRE) / 2000 lb/ton
Hourly Global Warming Potential	$GWP_{CH4, H}$	77.57	lb/hr	= $ER_{CH4, H}$ * 25 CO_2e
Annual Global Warming Potential	$GWP_{CH4, A}$	0.93	tpy	= $ER_{CH4, A}$ * 25 CO_2e
4. N_2O Emission Rate Calculations				
N_2O Emission Factor	F_{N2O}	0.00022	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2
N_2O Hourly Emission Rate	$ER_{N2O, H}$	**0.05**	**lb/hr**	= H_H * F_{N2O}
N_2O Annual Emission Rate	$ER_{N2O, A}$	**<0.01**	**tpy**	= H_A * F_{N2O} / 2000 lbs/ton
Hourly Global Warming Potential	$GWP_{N2O, H}$	13.75	lb/hr	= $ER_{N2O, H}$ * 298 CO_2e
Annual Global Warming Potential	$GWP_{N2O, A}$	0.16	tpy	= $ER_{N2O, A}$ * 298 CO_2e
5. Total CO_2e Emission Rates				
Hourly Global Warming Potential	-	**28,890.59**	**lb/hr**	= $ER_{CO2, H}$ + $GWP_{CH4, H}$ + $GWP_{N2O, H}$
Annual Global Warming Potential	-	**346.69**	**tpy**	= $ER_{CO2, A}$ + $GWP_{CH4, A}$ + $GWP_{N2O, A}$

Table D-5 (Revised April 2014)
Equipment Clearing - MSS Potential Emission
CCI Corpus Christi LLC

A. Equipment Clearing Heat Input to Flare

Material	Total Equipment Volume (scf/yr) (1)	Largest Vessel Volume (scf/hr) (2)	MW (lb/lb-mol)	Heating Value (Btu/lb)	Annual Mass to Flare (lb/yr)	Hourly Mass to Flare (lb/hr)	Annual Heat Input to Flare (MMBtu/yr)	Hourly Heat Input to Flare (MMBtu/hr)
	Q_A	Q_H		HHV	M_A (3)	M_H (4)	H_A (5)	H_H (6)
Naphtha	4,914	2,402	69	23,214	879.68	429.96	20.42	9.98
Jet Fuel	16,664	5,388	130	19,286	5,620.93	1,817.36	108.40	35.05
Diesel	1,720	862	130	19,296	580.27	290.78	11.20	5.61
Condensate	39,180	29,575	67	19,580	6,811.23	5,141.45	133.36	100.67
Gas Oil	909	862	130	19,718	306.67	290.78	6.05	5.73

Notes:

(1) Annual volume is based on sum of all equipment servicing each material.

(2) Hourly volume is based on largest equipment volume.

(3) $M_A = Q_A \times MW / 385$ scf/lb-mol

(4) $M_H = Q_H \times MW / 385$ scf/lb-mol

(5) $H_A = HHV \times M_A / 1{,}000{,}000$

(6) $H_H = HHV \times M_H / 1{,}000{,}000$

B. GHG Emissions from Equipment Clearing

Material	CO_2 Emission Factor (1)	CO_2 Emissions		CH_4 Emission Factor (2)	CH_4 Emissions		N_2O Emission Factor (2)	N_2O Emissions		CO_2e Emissions (5)	
	kg/MMBtu	lb/hr (3)	TPY (4)	kg /MMBtu	lb/hr (3)	TPY (4)	kg /MMBtu	lb/hr (3)	TPY (4)	lb/hr	TPY
Naphtha	68.02	1,497.01	1.53	0.003	0.07	0.0001	0.0006	0.01	0.00001	1,502.60	1.54
Jet Fuel	72.22	5,581.40	8.63	0.003	0.23	0.0004	0.0006	0.05	0.00007	5,601.01	8.66
Diesel	73.96	915.02	0.91	0.003	0.04	0.00004	0.0006	0.01	0.00001	918.16	0.92
Condensate	74.49	16,535.02	10.95	0.003	0.67	0.0004	0.0006	0.13	0.00009	16,591.36	10.99
Gas Oil	73.96	935.05	0.49	0.003	0.04	0.00002	0.0006	0.01	0.00000	938.26	0.49
Total	-	**25,463.50**	**22.52**	-	**1.04**	**0.001**	-	**0.21**	**0.0002**	**25,551.38**	**22.60**

Notes:

(1) CO_2 emission factor is based on 40 CFR Part 98 Subpart C, Table C-1.

(2) CH_4 and N_2O emission factors are based on 40 CFR Part 98 Subpart C, Table C-2.

(3) Hourly emissions are based on emission factor * hourly heat input (MMBtu/hr) *2.205 lb/kg

(4) Annual emissions are based on the emission factor * annual heat input (MMBtu/yr)* 2.205 lb/kg / 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. GWP factors are based on the November 2013 revised Table A-1 of 40 CFR Part 98 Subpart A. GWP for CO_2, CH_4, and N_2O are 1, 25, and 298 respectively.

Table D-7 (Revised April 2014)
Fugitive Equipment Components - Potential Emissions
CCI Corpus Christi LLC

Component Type and Service	Estimated Number of New Components	USEPA SOCMI w/out C2 Emission Factor [(1)] (lb/hr-component)	Control Efficiency [(2)] (percent)	Calculated Emission Rates [(3)]	
				lb/hour	tpy
Valves					
Gas/Vapor	609	0.0089	97	0.16	0.71
Light Liquid	4,534	0.0035	97	0.48	2.09
Heavy liquid	586	0.0007	0	0.41	1.80
Pumps					
Light Liquid	115	0.0386	85	0.67	2.92
Heavy liquid	10	0.0161	0	0.16	0.71
Flanges/Connectors					
Gas/Vapor	1,094	0.0029	30	2.22	9.73
Light Liquid	6,694	0.0005	30	2.34	10.26
Heavy liquid	853	0.00007	30	0.04	0.18
Relief Valves					
Gas/Vapor	149	0.2293	97	1.02	4.49
Compressors					
Gas/Vapor	3	0.5027	85	0.23	0.99
			Total Emissions	7.73	33.87
			Total CH_4 [(4)]	3.63	15.92
			Total CO_2e [(5)]	**90.87**	**397.99**

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)

lb VOC / hr = 115 heavy liquid valves * 0.0386 lb VOC / hr / component * (100% -85%) = 0.67 lb VOC/hr

tons VOC / yr = 0.67 lb VOC / hr * 8760 hr /yr / 2000 lb/ton = 2.92 tons VOC/yr

(4) It is conservatively assumed that all components in Gas/vapor service are 100% methane.

(5) Global warming potential factor for CH_4 is 25 as indicated in the November 2013 revised Table A-1 of 40 CFR Part 98 Subpart A.

Table D-10 (Added April 2014)
Cooling Tower - Potential Emissions
CCI Corpus Christi LLC

A. Emission Factors (1) and Global Warming Potential (GWP) Equivalency Factors (2)

CH_4 Emission Factor = 0.7 lb CH_4/MMGal & CH_4 GWP = 25 tons of CO2 equivalent

B. Emission Calculations

Emission Source	Inlet Flow Rate (3)	CH_4 Emissions (4,5)		CO_2e Emissions	
	Gal/hr	lb/hr	tpy	lb/hr	tpy
Cooling Tower	600,000	0.42	1.84	10.50	45.99

Notes:

(1) Emission factor is based on AP-42 Table 5.1-2, with the conservative assumption that 100% of VOC is CH_4.

(2) Global warming potential factor for CH_4 is 25 based on 40 CFR Part 98 Subpart A, Table A-1.

(3) Inlet flow is based on total flow into the cooling tower.

(4) Hourly emissions are based on the emission factor and inlet flow rate.

(5) Annual emissions are based 8760 hours/year.

(6) CO_2e emissions are based on the CH_4 emissions times the GWP factor.

Table D-11 (Added April 2014)
Wastewater Treatment Plant - Potential Emissions
CCI Corpus Christi LLC

A. Emission Factors (1) and Global Warming Potential (GWP) Equivalency Factors (2)

CH_4 Emission Factor = 0.7 lb CH_4/MMGal & CH_4 GWP = 25 tons of CO2 equivalent

B. Annual Potential to Emit By Wastewater Treatment System Source

Unit Name	Controlled w/Carbon (or Equivalent)?	Emission Abatement Credit (3)	WATER9-Modeled Emission Rate (4)	
			lb/hr	Tons/year
Oil Water Separator	Yes	0.05	0.314	0.626
Aerobic Biotreatent Unit 1	No	1	2.098	4.150
Aerobic Biotreatent Unit 2	No	1	2.098	4.150
Clarifier 1	No	1	0.00051	0.00108
Clarifier 2	No	1	0.00051	0.00108
Sump 1	No	1	0.017	0.037
Sump 2	No	1	0.017	0.037
Sump 3	No	1	0.017	0.037
		Total VOC Emissions	**4.562**	**9.041**
		Total CH_4 Emissions (5)	**4.562**	**9.041**
		Total CO_2e Emissions (6)	**114.062**	**226.017**

Notes:

(1) Emission factor is based on AP-42 Table 5.1-2, with the conservative assumption that 100% of VOC is CH_4.

(2) Global warming potential factor for CH_4 is 25 based on 40 CFR Part 98 Subpart A, Table A-1.

(3) Emissions abatement credit is based on 95% VOC removal efficiency as specified in 63.139(C)(5) of 40 CFR Part 63, Subpart G.

(4) Emissions are based on the WATER9 model output (grams/second).

(5) It is conservatively assumed that all VOC emissions from wastewater treatment are methane.

(6) CO_2e emissions are based on the CH_4 emissions times the GWP factor.

CCI Corpus Christi LLC
Table 1(a) Emission Point Summary (Revised April 2014)

Date: 4/16/2014	**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							
									5. Building Height (Ft.)	6. Height Above Ground (Ft.)	7. Stack Exit Data			8. Fugitives		
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY	Zone	East (Meters)	North (Meters)			(A) Diameter (Ft.)	(B) Velocity (FPS)	(C) Temperature (°F)	(A) Length (Ft.)	(B) Width (Ft.)	(C) Axis Degrees
H-1	340-H1	Charge Preheater 1	CO_2	19,855.75	78,271.36	14	649,294	3,079,041	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.34	1.33											
			N_2O	0.03	0.13											
			CO_2e	19,874.19	78,344.06											
H-2	350-H1	Charge Preheater 2	CO_2	19,855.75	78,271.36	14	649,347	3,079,000	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.34	1.33											
			N_2O	0.03	0.13											
			CO_2e	19,874.19	78,344.06											
BL-1	240-B1	Boiler 1	CO_2	4,722.06	18,372.50	14	649,379	3,078,926	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.08	0.31											
			N_2O	0.01	0.03											
			CO_2e	4,726.44	18,389.56											
BL-2	240-B2	Boiler 2	CO_2	4,722.06	18,372.50	14	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.08	0.31											
			N_2O	0.01	0.03											
			CO_2e	4,726.44	18,389.56											
FL-1	330-FL1	Flare	CO_2	543.78	2,165.26	14	649,643	3,078,574	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	1.51	5.99											
			N_2O	<0.01	<0.01											
			CO_2e	581.73	2,316.36											

CCI Corpus Christi LLC
Table 1(a) Emission Point Summary (Revised April 2014)

Date: 4/16/2014	**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							
									5. Building Height (Ft.)	6. Height Above Ground (Ft.)	7. Stack Exit Data			8. Fugitives		
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY	Zone	East (Meters)	North (Meters)			(A) Diameter (Ft.)	(B) Velocity (FPS)	(C) Temperature (°F)	(A) Length (Ft.)	(B) Width (Ft.)	(C) Axis Degrees
FL-MSS	330-FL1	Flare-MSS	CO_2	54,262.77	368.11	14	649,643	3,078,574	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	4.14	0.04											
			N_2O	0.25	<0.01											
			CO_2e	54,441.98	369.29											
TK-MSS	Multiple FINS	Tank MSS (RTO emissions from degassing Tank)	CO_2	8,988.73	36.88	14	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.36	<0.01											
			N_2O	0.07	<0.01											
			CO_2e	9,019.34	37.01											
FUGS	FUGS	Fugitives	CO_2	-	-	14	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	3.63	15.92											
			N_2O	-	-											
			CO_2e	90.87	397.99											
MVCU	150-FL2	Marine Vapor Combustion Unit	CO_2	23,301.13	29,022.70	14	649,252	3,078,668	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.92	1.12											
			N_2O	0.18	0.22											
			CO_2e	23,377.28	29,116.27											
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_2O	0.02	<0.01											
			CO_2e	2,454.62	122.73											

CCI Corpus Christi LLC
Table 1(a) Emission Point Summary (Revised April 2014)

Date: 4/16/2014	**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**							
									5. Building Height (Ft.)	**6. Height Above Ground (Ft.)**	**7. Stack Exit Data**			**8. Fugitives**		
(A) EPN	**(B) FIN**	**(C) Name**		**(A) Pound Per Hour**	**(B) TPY**	**Zone**	**East (Meters)**	**North (Meters)**			**(A) Diameter (Ft.)**	**(B) Velocity (FPS)**	**(C) Temperature (°F)**	**(A) Length (Ft.)**	**(B) Width (Ft.)**	**(C) Axis Degrees**
FW-1	FW-1	Firewater Pump 1	CO_2	815.41	40.77	14	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.03	<0.01											
			N_2O	0.01	<0.01											
			CO_2e	818.21	40.91											
FW-2	FW-2	Firewater Pumpu 2	CO_2	815.41	40.77	14	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.03	<0.01											
			N_2O	0.01	<0.01											
			CO_2e	818.21	40.91											
CWT	240-CT1	Cooling Tower	CO_2	-	-	14	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.42	1.84											
			N_2O	-	-											
			CO_2e	10.50	45.99											
WWTP	190-T30	Wastewater Treatment Plant	CO_2	-	-	14	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	4.56	9.04											
			N_2O	-	-											
			CO_2e	114.06	226.02											

EPN = EMISSION POINT NUMBER

FIN = FACILITY IDENTIFICATION NUMBER

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

TABLE 2F (Revised April 2014)
PROJECT EMISSION INCREASE

Pollutant(1):	CO_2e	**Permit:**	TBD
Baseline Period:	**Not applicable (proposed new stationary source)**		

	Affected or Modified Facilities(2)		Permit No.	Actual Emissions(3)	A Baseline Emissions(4)	B Proposed Emissions(5)	Projected Actual Emissions	Difference (B-A)(6)	Correction(7)	Project Increase(8)
	FIN	EPN								
1	H-1	340-H1	TBD	-	-	78,344.06	-	78,344.06		78,344.06
2	H-2	350-H1	TBD	-	-	78,344.06	-	78,344.06		78,344.06
3	BL-1	240-B1	TBD	-	-	18,389.56	-	18,389.56		18,389.56
4	BL-2	240-B2	TBD	-	-	18,389.56	-	18,389.56		18,389.56
5	FL-1	330-FL1	TBD	-	-	2,316.36	-	2,316.36		2,316.36
6	FL-MSS	330-FL1	TBD	-	-	369.29	-	369.29		369.29
7	TK-MSS	Multiple FINS	TBD	-	-	37.01	-	37.01		37.01
8	FUGS	FUGS	TBD	-	-	397.99	-	397.99		397.99
9	MVCU	150-FL2	TBD	-	-	29,116.27	-	29,116.27		29,116.27
10	EMGEN	EMGEN	TBD	-	-	122.73	-	122.73		122.73
11	FW-1	FW-1	TBD	-	-	40.91		40.91		40.91
12	FW-2	FW-2	TBD	-	-	40.91		40.91		40.91
13	CWT	240-CT1	TBD	-	-	45.99	-	45.99		45.99
14	WWTP	190-T30	TBD	-	-	226.02	-	226.02		226.02
								Page Subtotal(9)	0.00	226,180.72

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).