Appendix V

Air Quality Environmental Documents

Air Quality Environmental Documents for Texas Gulf Terminals Inc. (TGTI) Deepwater Port License

Appendix A - Air Quality Information for Environmental Impact Statement

Appendix B - New Source Review Air Permit Application

Appendix C - Air Quality Analysis

Appendix D - Case-by-Case MACT Permit Application

Appendix E - Title V Permit Application

Appendix F - TCEQ Authorizations for Onshore Facilities

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AIR QUALITY INFORMATION FOR ENVIRONMENTAL IMPACT STATEMENT

Texas Gulf Terminals Inc.
Western Gulf of Mexico

Appendix A

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1. APPENDIX A

This section presents a summary of air quality information that supports the National Environmental Policy Act (NEPA) Environmental Impact Statement (EIS) analysis.

1.1. INTRODUCTION

NEPA (42 USC 4321 et seq.) is the foundation of modern American environmental protection in the United States and its commonwealths, territories, and possession. NEPA requires Federal agency decision-makers to consider all reasonably foreseeable environmental effects of their proposed actions and to involve and inform the public in the decision-making process.

This application provides environmental information pursuant to the Deepwater Port Act of 1974, as amended (DWPA), and in accordance with the U.S. Coast Guard's (USCG's) and the Maritime Administration's (MARAD) need to comply with NEPA. The DWPA Environmental Report accompanying this DWP application is presented to aid in facilitating this required NEPA Environmental Impact Analysis:

1.2. AIR QUALITY

In this document, air quality is defined as a measurement of pollutants in ambient air. Air quality as described here may be affected by proposed construction, operation, and decommissioning of the project. Emissions from onshore and offshore were evaluated for the Deepwater Port License (DWPL) application. A combination of short- and long-term predominantly minor impacts on air quality would be expected during construction, operation, and decommissioning of the proposed Project.

Short-term, negligible impacts on air quality would result from the operation of construction of the proposed onshore storage terminal facility (OSTF), and from the construction of the proposed Deep Water Port (DWP). This distinction and organization of the document allows for more focused agency review at the State and Federal level.

The remainder of this document is presented in the following sections:

- Construction
- Operation
- Decommissioning
- Alternatives Analysis

1.2.1 Construction

1.2.1.1. Offshore Impacts of Construction

Construction activities would produce air emissions, predominantly combustion emissions from engines associated with marine vessels, compressors, generators, and cranes. Impacts associated with the proposed project construction would be expected to be short-term, and negligible. Other construction activities such as welding would generate minor emissions, but these would be minor relative to the combustion emissions. Fugitive particulate matter emissions typically associated with construction projects would not occur for the offshore portions of the proposed project construction but some fugitive particulate emissions are expected from the onshore portion of construction.

Construction-related offshore equipment that would generate air emissions includes the following:

- Three (3) Amphibious Excavators
- Three (3) Excavators
- Three (3) Side booms
- Two (2) Hydraulic Power Packs
- HDD (Horizontal Directional Drilling) Rig (minimum 1,000,000-pound pullback)
- Offshore Support Vessel for HDD back reaming and pullback operations (i.e.: Jack-Up Work Boat)
- Barge(s) or Work Platform(s) for HDD Rig and HDD support in shallow water (<6' water depth)
- Two (2) Pipelaying Barge (minimum tension capacity of 440 kips and capacity for 30" concrete coated pipe)
- Three (3) Pulling Winch (Land Based – assumed to be 320 HP each)
- Two (2) SPM (Single Point Mooring) Installation Vessel / Tug Boats

1.2.1.2. Offshore Construction Emissions

Construction emission estimates were based on the duration of operation for each vessel, compressors, generators, and cranes and the total rated horsepower for each engines. Total days and hours of operation for each vessel were based on schedule. Vessel horsepower ratings were based on actual example vessels representative of those likely to be used for the Project. Details surrounding emission factors and calculation methodologies can be seen in the sections below.

1.2.1.3. Onshore Impacts of Construction

Construction activities would produce air emissions, predominantly combustion emissions from engines associated with non-road construction equipment and on-road vehicles. Non-road equipment would include compressors, cranes, generators, and welding equipment. On-road vehicles would include commuter vehicles, and gasoline-engine pickup trucks. Impacts associated with the proposed Project construction would last for the duration of the construction period, and would be minor, intermittent, highly localized to construction sites. Fugitive particulate matter emissions would also occur from soil disturbance at the construction site.

Construction-related onshore equipment that would generate air emissions includes the following:

- Pumps for Pressure Washing and Blast Cleaning
- Dive Boat
- Pick-up Trucks
- Generator and Air Compressor
- Welding Equipment

1.2.1.4. Onshore Construction Emissions

Construction emission estimates were based on the duration of operation and engine horsepower rating for each piece of construction equipment. Total days and hours of operation for each source were based on project schedule.

1.2.1.5. Construction Activity Emissions

Construction activities are categorized into the following

- Preparing Work Area
- Layout Pipe and Weld above Ground
- Excavate Trench and Installation of Pipe
- Pipeline Crossings, Special Sections and Tie-Ins
- Final Backfill and Reinstatement Works
- Facilities and Pipeline Control

Emission sources are grouped into the following categories and can be seen in the detailed emission calculations.

- Layout Pipe and Weld above Ground; Pipeline Crossings, Special Sections and Tie-Ins
- Excavate Trench and Installation of Pipe
- Installation of SPM and Components
- Testing and Commissioning
- Miscellaneous activities

The following sections present a summary of the emissions calculation methodologies, emission factors, and operating parameter assumptions used in developing emissions calculations for the various onshore and offshore equipment and miscellaneous activities listed in the previous sections of this document.

SUPPORT VESSEL FOR RIG PULLBACK, DIVING AND OTHER OPERATIONS

Three boats with a twin engine and combined HP rating of 1500 HP are expected be used for this purpose. One boat is used for diving while two boats are used for rig pullback activities.

Boat Twin Engines
Detailed specifications of these engines are not available therefore typical specifications are assumed.

Emission Factors – The sources of emission factors used to estimate emissions for the main engine are summarized below.

- **AP-42, Section 3.4. Large Stationary Diesel and All Stationary Dual-fuel Engines** –Particulate matter, CO and VOC emissions estimates for the engine are based on AP-42, Section 3.4 emission factors. Non methane VOC emission factor has been taken as 91% of TOC emission factor. Total particulate emissions have been taken as the sum of filterable and condensable particulate emissions. An average BSFC of 7,000 Btu/hp-hr has been used to convert emission factors from lb/MMBtu to lb/hp-hr.

- **Mass Balance** – SO_2 emissions are calculated based on a maximum sulfur content of 1000 ppm in diesel fuel per IMO 2015 standards. It is assumed that 98 percent of sulfur in the fuel is oxidized to SO_2 and 2 percent of sulfur in the fuel is oxidized to sulfuric acid (H_2SO_4) mist based on Section 4.1.1 of Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003. Emissions of

Hydrogen sulfide (H_2S), total reduced sulfur (TRS), and reduced sulfur compounds resulting from sulfur content in the fuel are negligible.

- **IMO Tier 2** – NO_x emissions estimates for the engines are based on IMO Tier 2 emission factors for an engine speed of 1,800 rpm. Speed of 1800 rpm is assumed based on other engines of comparable capacity and specifications.

- **EPA Regulations –** CO_2, CH_4, and N_2O emission factors are obtained from 40 CFR 98 Subpart C, Table C-1 (Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel) and Table C-2 (Default CH_4 and N_2O Emission Factors for Various Types of Fuel). Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

Operating Parameters – The maximum hourly, and annual emissions from these engine are calculated based on the following operating parameters.

- **Maximum Hourly Emissions –** The maximum hourly emissions for the main engines are calculated based on engine brake horse power 1500 HP at 100% operating capacity during usage.

- **Annual Emissions** – Support vessel total emissions are based on 24 hours a day of operation for 22 weeks while the emissions from the diving boats are based on operation of 12 hours a day for 22 weeks. The selected emission factors used for these pollutants are shown in the emission calculations.

SPM Installation Tug Boats

Two tug boats contain 2 main engines with a combined engine HP rating of 8000 HP and two auxiliary engines per boat with a rating of 500 HP each are expected be used for SPM installation. Detailed specifications of these engines are not available therefore typical specifications are assumed.

Emission Factors – The sources of emission factors used to estimate emissions for the main engine are summarized below.

- **AP-42, Section 3.4. Large Stationary Diesel and All Stationary Dual-fuel Engines** –Particulate matter, CO and VOC emissions estimates for the engine are based on AP-42, Section 3.4 emission factors. Non methane VOC emission factor has been taken as 91% of TOC emission factor. Total particulate emissions have been taken as the sum of filterable and condensable particulate emissions. An average BSFC of 7,000 Btu/hp-hr has been used to convert emission factors from lb/MMBtu to lb/hp-hr.

- **Mass Balance** – SO_2 emissions are calculated based on a maximum sulfur content of 1000 ppm in diesel fuel per IMO 2015 standards. It is assumed that 98 percent of sulfur in the fuel is oxidized to SO_2 and 2 percent of sulfur in the fuel is oxidized to sulfuric acid (H_2SO_4) mist based on Section 4.1.1 of Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003. Emissions of Hydrogen sulfide (H_2S), total reduced sulfur (TRS), and reduced sulfur compounds resulting from sulfur content in the fuel are negligible.

- **IMO Tier 2** – NO_x emissions estimates for the engines are based on IMO Tier 2 emission factors for an engine speed of 1,800 rpm. Speed of 1800 rpm is assumed based on other engines of comparable capacity and specifications.

- **EPA Regulations –** CO_2, CH_4, and N_2O emission factors are obtained from 40 CFR 98 Subpart C, Table C-1 (Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel) and Table C-2 (Default CH_4 and N_2O Emission Factors for Various Types of Fuel). Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

Operating Parameters – The maximum hourly, and annual emissions from these engine are calculated based on the following operating parameters.

- **Maximum Hourly Emissions –** The maximum hourly emissions for the main engines are calculated based on engine brake horse power 9000 HP at 100% operating capacity during usage.

- **Annual Emissions** – Total emissions are based on 3192 hours (19 weeks 24 hours a day) of operation. The selected emission factors used for these pollutants are shown in the emission calculations.

PIPELAY BARGE

Two pipelay barges contain three generators with a combined capacity of 3300 HP. Detailed specifications of these generators is not available therefore typical specifications are assumed. For a conservative emission estimation it is assumed that they operate at 100% capacity for 12 hours a day for a total of 22 weeks.

Emission Factors – The sources of emission factors used to estimate emissions for the generator engines are summarized below.

- **AP-42, Section 3.4. Large Stationary Diesel and All Stationary Dual-fuel Engines** –Particulate matter, CO and VOC emissions estimates for the engine are based on AP-42, Section 3.4 emission factors. Non methane VOC emission factor has been taken as 91% of TOC emission factor. Total particulate emissions have been taken as the sum of filterable and condensable particulate emissions. An average BSFC of 7,000 Btu/hp-hr has been used to convert emission factors from lb/MMBtu to lb/hp-hr.

- **Mass Balance** – SO_2 emissions are calculated based on a maximum sulfur content of 1000 ppm in diesel fuel per IMO 2015 standards. It is assumed that 98 percent of sulfur in the fuel is oxidized to SO_2 and 2 percent of sulfur in the fuel is oxidized to sulfuric acid (H_2SO_4) mist based on Section 4.1.1 of Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003. Emissions of Hydrogen sulfide (H_2S), total reduced sulfur (TRS), and reduced sulfur compounds resulting from sulfur content in the fuel are negligible.

- **IMO Tier 2** – NO_x emissions estimates for the engines are based on IMO Tier 2 emission factors for an engine speed of 1,800 rpm. Speed of 1800 rpm is assumed based on other engines of comparable capacity and specifications.

- **EPA Regulations –** CO_2, CH_4, and N_2O emission factors are obtained from 40 CFR 98 Subpart C, Table C-1 (Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel) and Table C-2 (Default CH_4 and N_2O Emission Factors for Various Types of Fuel). Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

Operating Parameters – The maximum hourly, and annual emissions from this engine are calculated based on the following operating parameters.

- **Maximum Hourly Emissions –** The maximum hourly emissions for the main engines are calculated based on engine brake horse power 3300 HP at 100% operating capacity during usage.

- **Annual Emissions** – Total emissions are based on 12 hours a day for 22 weeks of operation. The selected emission factors used for these pollutants are shown in the emission calculations.

SHALLOW WATER BARGE

One shallow water barge to support the HDD rig with an engine capacity of 100 HP is expected to be used. Detailed specifications of this unit is not available therefore typical specifications are assumed. For a conservative emission estimation it is assumed that they operate at 100% operating capacity for 24 hours a day for a total of 22 weeks.

Emission Factors – The sources of emission factors used to estimate emissions for the engines are summarized below.

- **AP-42, Section 3.3. Uncontrolled Gasoline and Diesel Industrial Engines** –Particulate matter, CO and VOC emissions estimates for the engine are based on AP-42, Section 3 emission factors. Emission factors for diesel fuel are used. All TOC is assumed to be VOC. TOC emission factor has been calculated as the sum of exhaust and crankcase emission factors.

- **Mass Balance** – SO_2 emissions are calculated based on a maximum sulfur content of 1000 ppm in diesel fuel per IMO 2015 standards. It is assumed that 98 percent of sulfur in the fuel is oxidized to SO_2 and 2 percent of sulfur in the fuel is oxidized to sulfuric acid (H_2SO_4) mist based on Section 4.1.1 of Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003. Emissions of Hydrogen sulfide (H_2S), total reduced sulfur (TRS), and reduced sulfur compounds resulting from sulfur content in the fuel are negligible.

- **IMO Tier 2** – NO_x emissions estimates for the engines are based on IMO Tier 2 emission factors for an engine speed of 1,800 rpm. Speed of 1800 rpm is assumed based on other engines of comparable capacity and specifications.

- **EPA Regulations –** CO_2, CH_4, and N_2O emission factors are obtained from 40 CFR 98 Subpart C, Table C-1 (Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel) and Table C-2 (Default CH_4 and N_2O Emission Factors for Various Types of Fuel). Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

Operating Parameters – The maximum hourly, and annual emissions from this engine are calculated based on the following operating parameters.

- **Maximum Hourly Emissions –** The maximum hourly emissions for the main engines are calculated based on engine brake horse power 100 HP at 100% operating capacity during usage.

- **Annual Emissions** – Total emissions are based on 24 hours a day for 22 weeks of operation. The selected emission factors used for these pollutants are shown in the emission calculations.

WELDING, GENERATOR, AIR COMPRESSOR AND PUMP COMBUSTION EMISSIONS

Per the information received from TGTI, 9 welding units, 3 generator units, 2 air compressors and 5 pressure washer and/or blast cleaning pumps are expected to be used. Welding Unit expected to have a rating of 8.5 HP, the generating unit is expected to have a rating of 17 HP, the air compressor is expected to have a rating of 120 HP and the pumps are expected to have a rating of 50 HP. For a conservative emission estimation it is assumed that the welding, pumps and generating units operate at 100% operating capacity for 12 hours a day for a total of 22 weeks while the air compressor operates at 100% operating capacity for 24 hours a day for a total of 14 days.

Emission and Adjustment Factors – The sources of emission factors used to estimate combustion emissions for these equipment are summarized below.

- **EPA Report No. NR-009A** –Criteria emission factors have been obtained from "Exhaust Emission Factors for Nonroad Engine Modeling --Compression Ignition", Report No. NR-009A, revised June 15, 1998, US EPA Office of Mobile Sources. Steady-state emissions factors for CI engines obtained from Table 1, assuming 1988-99 model year engines, not subject to Tier 1 or Tier 2 controls. SO_2 emission factor based on break-specific fuel consumption (BSFC) given in Table 1 and assuming default sulfur content for ULSD (15 ppm).
  *SO2 EF = (BSFC * 453.6* (1 - 0.022) - HC) * 15/1000000 * 2; where 453.6 is the conversion factor from pounds to grams; 1-0.022 is an adjustment for sulfur converted to direct PM; HC is the in-use adjusted hydrocarbon emissions in g/hp-hr; 15 ppm is the default wt. fraction of sulfur in ULSD; 2 is the grams of SO_2 formed from a gram of sulfur.*

- **EPA Report No. NR-009d** - In-use adjustment factors are obtained from "Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling -- Compression Ignition, Table F-3", Report No. NR-009d, revised July 2010, US EPA Office of transportation and Air Quality.

- **EPA Report EPA430-K-08-004 –** CO2 emission factor was obtained from USEPA "Direct Emissions from Mobile Combustion Sources, May 2008, EPA430-K-08-004" - Table B-1: Factors for Calculating CO2 Emissions from Motor Gasoline and Diesel Fuel Use". CH4 and N2O emission factors are obtained from Table A-6. CH4 and N2O Emission Factors for Non-Highway Vehicles". Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

Operating Parameters – The maximum hourly, and annual emissions from these equipment are calculated based on the following operating parameters.

- **Maximum Hourly Emissions –** The maximum hourly emissions for these welding, generator, air compressor and pumps equipment are calculated based on engine brake horse power 8.5 HP, 17 HP, 120 HP and 50 HP respectively at 100% operating capacity during usage.

- **Annual Emissions** – Total emissions for the welding, generator and pump units are based on 12 hours a day for 22 weeks of operation. Total emissions for the air compressor are based on 14 days of operation for 24 hours a day. The selected emission factors used for these pollutants are shown in the emission calculations.

EXCAVATORS COMBUSTION EMISSIONS

Per the information received from TGTI, 6 diesel fired excavators with a rating of 200 HP are expected to be used. Three of these units will be amphibious and other three will be regular. For a conservative emission estimation it is assumed that they operate at 100% operating capacity for 12 hours a day for a total of 22 weeks.

Emission and Adjustment Factors – The sources of emission factors used to estimate combustion emissions for the excavators are summarized below.

- **EPA Report No. NR-009A** –Criteria emission factors have been obtained from "Exhaust Emission Factors for Nonroad Engine Modeling --Compression Ignition", Report No. NR-009A, revised June 15, 1998, US EPA Office of Mobile Sources. Steady-state emissions factors for CI engines obtained from Table 1, assuming 1988-99 model year engines, not subject to Tier 1 or Tier 2 controls. SO_2 emission factor based on break-specific fuel consumption (BSFC) given in Table 1 and assuming default ULSD sulfur content of 15 ppm.

  *SO2 EF = (BSFC * 453.6* (1 - 0.022) - HC) * 15/1000000 * 2; where 453.6 is the conversion factor from pounds to grams; 1-0.022 is an adjustment for sulfur converted to direct PM; HC is the in-use adjusted hydrocarbon emissions in g/hp-hr; 15 ppm is the default wt. fraction of sulfur in ULSD; 2 is the grams of SO_2 formed from a gram of sulfur.*

- **EPA Report No. NR-009d** - In-use adjustment factors are obtained from "Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling -- Compression Ignition, Table F-3", Report No. NR-009d, revised July 2010, US EPA Office of transportation and Air Quality.

- **EPA Report EPA430-K-08-004 –** CO_2 emission factor was obtained from USEPA "Direct Emissions from Mobile Combustion Sources, May 2008, EPA430-K-08-004" - Table B-1: Factors for Calculating CO_2 Emissions from Motor Gasoline and Diesel Fuel Use". CH_4 and N_2O emission factors are obtained from Table A-6. CH_4 and N2O Emission Factors for Non-Highway Vehicles". Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

Operating Parameters – The maximum hourly, and annual emissions from these equipment are calculated based on the following operating parameters.

- **Maximum Hourly Emissions –** The maximum hourly emissions for these equipment are calculated based on engine brake horse power 200 HP respectively at 100% operating capacity during usage.

- **Annual Emissions** – Total emissions are based on 12 hours a day for 22 weeks of operation. The selected emission factors used for these pollutants are shown in the emission calculations.

SIDE-BOOMS, PULLING WENCH, CRANE AND HYDRAULIC POWER PACK COMBUSTION EMISSIONS

Per the information received from TGTI, 4 diesel fired side-booms with a rating of 240 HP, 3 pulling wench with an assumed rating of 320 HP, one contractor's crane with an assumed capacity of 625 HP and two hydraulic power packs with an assumed rating of 778 HP are expected to be used. For a conservative emission estimation it is assumed that the side-booms and pulling wench operate at 100% operating capacity for 12 hours a day for a

total of 22 weeks while the crane operates at 100% operating capacity for 24 hours a day for a total of 22 weeks. Hydraulic Power pack operates at a 100% capacity for a total of 3192 hours.

Emission and Adjustment Factors – The sources of emission factors used to estimate combustion emissions for these equipment are summarized below.

- **EPA Report No. NR-009A** –Criteria emission factors have been obtained from "Exhaust Emission Factors for Nonroad Engine Modeling --Compression Ignition", Report No. NR-009A, revised June 15, 1998, US EPA Office of Mobile Sources. Steady-state emissions factors for CI engines obtained from Table 1, assuming 1988-99 model year engines, not subject to Tier 1 or Tier 2 controls. SO_2 emission factor based on break-specific fuel consumption (BSFC) given in Table 1 and assuming default sulfur content of 15 ppm for ULSD.

  *SO2 EF = (BSFC * 453.6* (1 - 0.022) - HC) * 15/1000000 * 2; where 453.6 is the conversion factor from pounds to grams; 1-0.022 is an adjustment for sulfur converted to direct PM; HC is the in-use adjusted hydrocarbon emissions in g/hp-hr; 15 ppm is the default wt. fraction of sulfur in ULSD; 2 is the grams of SO_2 formed from a gram of sulfur.*

- **EPA Report No. NR-009d** - In-use adjustment factors are obtained from "Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling -- Compression Ignition, Table F-3", Report No. NR-009d, revised July 2010, US EPA Office of transportation and Air Quality.

- **EPA Report EPA430-K-08-004 –** CO_2 emission factor was obtained from USEPA "Direct Emissions from Mobile Combustion Sources, May 2008, EPA430-K-08-004" - Table B-1: Factors for Calculating CO_2 Emissions from Motor Gasoline and Diesel Fuel Use". CH_4 and N_2O emission factors are obtained from Table A-6. CH_4 and N_2O Emission Factors for Non-Highway Vehicles". Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

Operating Parameters – The maximum hourly, and annual emissions from these equipment are calculated based on the following operating parameters.

- **Maximum Hourly Emissions –** The maximum hourly emissions for these equipment are calculated based on engine brake horse power of 200, 320, 625 and 778 HP for the Side-Booms, the Pulling Wench, the Crane and hydraulic power packs respectively at 100% operating capacity during usage.

- **Annual Emissions** – Total emissions are based on 12 hours a day for 22 weeks of operation for the side-booms and the pulling wench. For the crane, they are based on 24 hours of operation for 22 weeks. For the hydraulic power packs, emissions are based on a total of 3192 hours. The selected emission factors used for these pollutants are shown in the emission calculations.

FUGITIVE DUST EMISSIONS

The onshore construction area is expected to have some particulate emissions related to various construction activities for the duration of the construction. It is assumed that this lasts for a total of 22 weeks and the area of the on-shore construction site is conservatively estimated at 3 acres.

Emission Factors – The sources of emission factors used to estimate combustion emissions for these equipment are summarized below.

- **AP 42 Emission Factors** – EPA emission factor of 1.2 tons/acre/month of activity is obtained from Section 13.2.3 of AP-42. Emission factor is most applicable to a semiarid climate; therefore, calculated emissions should exceed those for the actual site. Emissions listed are upper bound estimates for fugitive total suspended particulates (TSP) generated by construction activities. Emissions assume a 50% control due to application of dust suppressants.

Operating Parameters – The maximum hourly, and annual emissions from these equipment are calculated based on the following operating parameters.

- **Hourly Emissions –** Average hourly emissions are based on total emissions calculated divided by the construction duration of 22 weeks.

- **Annual Emissions** – Total emissions are based on 22 weeks of operation.

WORKERS COMMUTE (VEHICULAR) EMISSIONS

Per the information provided by TGTI, 60 workers are expected to commute in/around the onshore construction site during the construction period. It is assumed that they will be using Light Duty Gasoline Trucks (LDGT). It is assumed that they will be travelling 15 miles a day. In addition it is also assumed that 4 pick-up trucks will be used at the construction site for work related activities. It is assumed that this travel will average to 20 miles per day per truck.

Emission Factors – The sources of emission factors used to estimate combustion emissions for these equipment are summarized below.

- **AP 42 Emission Factors** – Emission factors for LDGT are obtained from USEPA Fact Sheet "Average Annual Emissions and Fuel Consumption for Gasoline-Fueled Passenger Cars and Light Trucks". CO_2 Emission factors are obtained from USEPA "Direct Emissions from Mobile Combustion Sources, May 2008, EPA430-K-08-004; Table 5. Factors for Gasoline and On-Road Diesel Fuels". Fuel economy values are obtained from USEPA "Direct Emissions from Mobile Combustion Sources, May 2008, EPA430-K-08-004; Table 4. Fuel Economy Values by Vehicle Type". CH_4 and N_2O Emission factors are obtained from USEPA "Direct Emissions from Mobile Combustion Sources, May 2008, EPA430-K-08-004; Table 2. CH_4 and N_2O Emission Factors for Highway Vehicles". Emission factors for uncontrolled sources were used. SO_2 emission factors are obtained from "USEPA AP-42 Chapter 3.3-Gasoline and Diesel Industrial Engines, Table3.3-1. Emissions were calculated based on assumptions that the vehicles would be travelling at 35 mph; and LDGT are of 150 hp.

Operating Parameters – The maximum hourly, and annual emissions from these equipment are calculated based on the following operating parameters.

- **Hourly Emissions –** Hourly Emissions are based on 12 hour work-days.

- **Annual Emissions** – Total emissions are based on 22 weeks of daily commute activities.

Detailed calculations can be seen in Tables A-6 through A-55 at the end of this appendix.

1.2.2 Operation

1.2.2.1 Laws and Regulations

In addition to the DWPA and NEPA, the following laws and regulations apply to offshore air quality:

- Clean Air Act, including:
  - National Ambient Air Quality Standards (NAAQS),
  - Air quality control regions (AQCRs),
  - New Source Performance Standards (NSPS),
  - National Emission Standards for Hazardous Air Pollutants (NESHAP), and
- Texas Commission on Environmental Quality (TCEQ) Emissions Standards and Regulatory Requirements.

1.2.2.2 Offshore Required Permits

For compliance with the abovementioned laws and regulations, the DWP may be required to obtain the following permits prior to construction and operation:

- Prevention of Significant Deterioration (PSD) Permit
- Major Source Hazardous Air Pollutant Permit, and
- Title V Operating Permit

1.2.2.3 DWP New Source Definition for Clean Air Act Applicability

Per the 1974 DWPA, the revised 2012 DWPA, and the DWP regulations (40 CFR 148.5), a DWP new source for purposes of the Clean Air Act is defined as "any fixed or floating manmade structure other than a vessel, or any group of such structures, that are located beyond State seaward boundaries and that are used or intended for use as a port or terminal for the transportation, storage, or further handling of oil or natural gas for transportation to or from any State…" Accordingly, vessels are not considered primary/direct sources of emissions from the Project for Clean Air Act new source review regulatory applicability.

1.2.2.4 Offshore Existing Threats

Drilling platforms, drill rigs, derrick barges, and pipeline construction barges all contribute to emissions, negatively impacting air quality. Commercial and private vessels are also sources of emissions which may negatively impact air quality.

1.2.2.5 Offshore Existing Conditions

Existing conditions, including offshore regional climate, existing ambient air quality, and greenhouse gasses and climate change are discussed in the following subsections.

1.2.2.6 Offshore Regional Climate

The location for the proposed Port is in the Gulf of Mexico, approximately 14 nautical miles off the cost of North Padre Island in Kleberg County, Texas. Although descriptions of regional climate do not typically include areas of open water, the nearest coastal climate can be described. The Gulf Coast of Texas can be classified as having a warm, humid climate with hot summers (Köppen-Geiger climate classification Cfa) (NOAA 2017). Historic data from Corpus Christi International Airport, indicate a mean daily temperature ranging from 84.2°F in August to 55°F in January, with mean daily highs ranging up to 94°F in August, and mean daily lows ranging down to 45.3°F in January. Mean annual precipitation is 32 inches, distributed relatively evenly throughout the year (NOAA 2017).

The entire Gulf of Mexico and its coastal areas are subject to tropical storms and hurricanes, which are most likely to occur between late May and early November. On average, the proposed Project area will experience a tropical storm (sustained winds of at least 39 miles per hour, or 17 m/s) every 1 or 2 years, while a hurricane (sustained winds of at least 74 miles per hour, or 33 m/s) can be expected to cross the proposed Project area once every 4 to 5 years. A "major" hurricane rated as Category 3 or higher (sustained winds of at least 110 miles per hour, or 50 m/s) may occur about once every 25 years. At the proposed Port location, storms have the potential to produce significant waves that present a hazard to ocean-going vessels. Along coastal locations, heavy rains and wind-driven storm surges may cause local or widespread flooding

1.2.2.7 Offshore Existing Ambient Air Quality

NAAQS were developed by the USEPA to protect public health (primary standards) and public welfare (secondary standards). Primary standards are based on observable human health responses and are set at levels that provide an adequate margin of safety for sensitive segments of the population. Secondary standards are intended to protect welfare interests such as structures, vegetation, and livestock. Air dispersion modeling is used by proposed new sources to demonstrate compliance with both the primary or secondary standards. States use ambient air monitoring systems to determine whether AQCRs are meeting the NAAQS. Areas meeting the NAAQS are termed attainment areas, and areas not meeting the NAAQS are termed nonattainment areas. Areas that have insufficient data to make a determination of attainment/nonattainment are unclassified or are not designated, but are treated as being attainment areas for permitting purposes. The designation of an area is made on a pollutant-specific basis.

For offshore locations beyond the seaward state territorial boundary, no status has been designated with respect to the NAAQS. Therefore, the NAAQS attainment status of the nearest adjacent onshore location should be considered. Currently, there are no active monitoring stations for NO_2 located in in Kleberg County. [1] Therefore, Texas Gulf Terminals Inc. selected the Channelview Monitor, EPA Site Number 48-201-0026, located in Harris County near Houston, Texas as the conservative/representative monitor for the DWP NO_2 background concentrations. Additionally, Texas Gulf Terminals Inc. selected the Corpus Christi Dona Park Monitor, EPA Site Number 48-355-0034 (Dona Park Monitor), as the representative monitor for the DWP for SO_2 and $PM_{2.5}$ background concentrations. Further information pertaining to the criteria's used to determine the monitoring stations are provided in the modeling report included in Appendix C of this license application. The monitoring values shown are for the 3-year period of 2014 through 2016. The existing background concentrations at the proposed Port location are likely to be lower than the values shown, due to the scarcity of nearby emission sources relative to the onshore monitoring sites.

[1] Information Obtained from EPA's Air Data website and TCEQ's Geo TAM website.

Table A-1. Background Ambient Air Quality and Ambient Air Quality Standards

Air Pollutant	Averaging Period	Statistic	Monitor Values	Monitoring Site	Primary NAAQS
Sulfur Dioxide (SO_2)	1-hour	99th percentile of 1-hour daily maximum concentrations, averaged over 3 years	4 ppb	Dona Park, TX (48-355-0034)	75 ppb
Carbon Monoxide (CO)	1-hour	Not to be Exceeded more than once per year	1.9 ppm	Brownsville Monitor (48-061-0006)	35 ppm
	8-hour		1 ppm		9 ppm
Nitrogen Dioxide (NO_2)	1-hour	98th percentile of 1-hour daily maximum concentrations, averaged over 3 years	87 μg/m^3	Channel View, TX (48-201-0026)	100 ppb
	Annual	Annual Mean	18 μg/m^3		53 ppb
Ozone (O_3)	8-hour	Annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years	64 ppb	Corpus Christi West Monitor (48-355-0025)	70 ppb
Particulate Matter (PM_{10})	24-hour	Not to be exceeded more than once per year on average over 3 years	87 μg/m^3	Dona Park (48-355-0034)	150 μg/m^3
Particulate Matter ($PM_{2.5}$)	24-hour	98th percentile, averaged over 3 years	22 μg/m^3	Dona Park, TX (48-355-0034)	35 μg/m^3
	Annual	annual mean, averaged over 3 years	8.9 μg/m^3		12 μg/m^3
Lead (Pb)	Rolling 3-month	Not to be exceeded	0.01 μg/m^3	Brownsville Monitor (48-061-0006)	0.15 μg/m^3

1.2.2.8 Offshore Greenhouse Gases

Key greenhouse gases (GHGs) potentially emitted by (and potentially offset by) the proposed Project are carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O).

1.2.2.9 Offshore Greenhouse Gas Regulations

The proposed DWP source will not exceed the PSD major source threshold for emissions of greenhouse gases. The proposed DWP will also not be subject to the sector-specific or stationary combustion source GHG reporting requirements under 40 CFR 98.

1.2.2.10 Offshore Impacts of Operation

Impacts associated with the proposed Project operation would be expected to be long-term. Air quality impacts for the offshore operations portion of the Project were evaluated and provided in Appendix C of this application.

This modeling analysis demonstrates that operating impacts for the offshore portion of the Project would acceptable and in compliance with all Federal and State ambient standards.

1.2.2.11 Offshore Operation Emissions

Operational emissions from the offshore portion of the Project would be produced by loading of crude/condensate into the crude carriers, fugitive components of the SPM buoy, and from mobile sources, which would include combustion emissions from visiting crude carriers, support vessels (tug boats, pilot ships), and helicopter flights.

The following section presents a summary of the emissions calculation methodologies, emission factors, and operating parameter assumptions used in developing emissions calculations for the crude carriers, the support vessels, and miscellaneous activities.

MARINE LOADING

Emissions from marine loading of Crude Oil/Condensate are calculated based on TCEQ's Air Permit Technical Guidance for Chemical Sources: Loading Operations (October 2000) using the following equation from U.S. EPA's AP-42, Section 5.2:

$$L = 12.46 \times S \times P \times M/T$$

where:

L = Loading Loss (lb/10^3 gal of liquid loaded)
S = Saturation factor
P = True vapor pressure of liquid loaded (psia)
M = Molecular weight of vapors (lb/lbmole)
T = Temperature of bulk liquid loaded (R)

A saturation factor of 0.2 is used for submerged loading using crude carriers. A maximum true vapor pressure of 11 psia is used for crude oil/condensate loading.

EQUIVALENCY DETERMINATION

As mentioned previously, TGTI will operate various emission units for which exact specifications are not available at this time due to scheduling and other contractual agreements that will be completed in the future. TGTI has proposed representative emission units to develop the PTE while maintaining sufficient operational flexibility to provide the ability to utilize various, 'equivalent' operational equipment. TGTI proposes the demonstration of 'equivalency' based on the following factors:

- Equal or lower mass emissions for each criteria, toxic, and other regulated air pollutants on a short-term (e.g., lbs/hr and lbs/day) and a long-term (e.g., ton/year) basis;
- Compliance with applicable regulations (e.g., 40 CFR 60, 40 CFR 63);
- Compliance with applicable certifications (e.g., EPA Tier II, IMO Tier II); and
- Compliance with applicable BACT requirements identified for a representative equipment.

A list of equipment for which TGTI is requesting above-mentioned flexibility is provided below.

- Supply vessels, pilot boats and all associated air pollution sources;
- Various third party equipment

- Tug boats and all associated air pollution sources;

CRUDE CARRIER

The emissions sources on the Crude Carrier (VLCC, ULCC) include main engines, auxiliary engine, cranes, power packs, boilers, cargo pumps, stripping pumps and ballast pumps.

Carrier Main Engine
TGTI has proposed three carriers that can be used for loading purposes. These include Apolytares Q88, Fontana 899x157 and Seaways Raphael 1098x190. Apolytares Q88 is the largest of these carriers and will therefore be used as a representative case for emission estimation purposes. The Apolytares Q88 carrier consists of one main engine and 3 auxiliary engines. The main engine is a Hyundai BW 6S90MC-C MK7 29340 KW engine while the auxiliary engines are three identical Hyundai Himsen 7H21/32 1200 KW engines. Please note that this carrier was built/delivered on April 2 2009 per the specifications document received from TGTI. Therefore for NOx emission standards for these engines comply with IMO Tier I.

Emission Factors – The sources of emission factors used to estimate emissions for the main engine are summarized below.

- **BOEM Year 2011 Gulfwide Emission Inventory Study (BOEM 2014-666)** - Crude Carrier emission factors for Criteria emission calculations except VOC and SO_2 are based on Table 6-1 Year 2011 Gulfwide Emission Inventory Study (BOEM 2014-666) for Commercial Marine Vessels for Diesel. The factors used correspond to LOOP Tankers. No adjustment to emissions are being made for the load factor. The report is available online and can be seen at https://www.boem.gov/ESPIS/5/5440.pdf.

- **Mass Balance** – Sulfur content of 0.1% is used for all diesel combustion sources per IMO standards for 2015. Therefore, SO_2 emissions are calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO_2 and 2 percent of sulfur in the fuel is oxidized to sulfuric acid (H_2SO_4) mist based on Section 4.1.1 of Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003. Emissions of Hydrogen sulfide (H_2S), total reduced sulfur (TRS), and reduced sulfur compounds resulting from sulfur content in the fuel are negligible.

- **EPA Guidance Documents** – Lead emission factor is obtained from EPA's guidance document: *Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2*. Emission factor for distillate oil-fired gas turbines was used as a surrogate for distillate oil-fired engines due to unavailability of emission factors.

- **AP-42, Section 3.4. Large Stationary Diesel and All Stationary Dual-fuel Engines** –VOC and HAP emissions estimates for the main engine are based on AP-42, Section 3.4 emission factors (Table 3.4-1, Table 3.4-2, and Table 3.4-3). Non-methane VOC emission factor has been taken as 91% of the total organic compounds (TOC) emission factor. An average brake-specific fuel consumption (BSFC) 192 g/kW-hr is used to calculate the engine heat input (5,708 Btu/hp-hr), which is used to convert emission factors from lb/MMBtu to lb/hp-hr.

- **EPA Regulations –** CO_2, CH_4, and N_2O emission factors are obtained from 40 CFR 98 Subpart C, Table C-1 (Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel) and Table C-2 (Default CH_4 and N_2O Emission Factors for Various Types of Fuel). Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

Operating Parameters – The maximum hourly, daily, and annual emissions from the main engine are calculated based on the following operating parameters.

- **Maximum Hourly and Daily Emissions –** The maximum hourly emissions for the main engines are calculated based on engine brake horse power 39,345 HP at 25% capacity during the time the vessels is in the safety zone. Daily emissions are based on 24 hours a day of operation. This is a conservative estimation as the main engine is not supposed to operate while they are in the safety zone and tugged by the tug boats.

- **Annual Emissions** – Maximum number of VLCCs or ULCCs that can load during a given month are 8 and it takes 2 days for them to load. This equates to a conservative estimate of 4608 hours a year. The selected emission factors used for these pollutants are shown in the emission calculations.

Crude Carrier Auxiliary Engines
As explained in the last section, the Apolytares Q88 carrier consists of one main engine and 3 auxiliary engines. These engines are identical Hyundai Himsen 7H21/32 1200 KW engines. Please note that this carrier was built/delivered on April 2, 2009 per the specifications document received from TGTI. Therefore for NO_x emission standards for these engines comply with IMO Tier I.

Emission Factors – The sources of emission factors used to estimate emissions for each of the three engines are summarized below.

- **AP-42, Section 3.4. Large Stationary Diesel and All Stationary Dual-fuel Engines** – Particulate matter (PM, PM_{10}, and $PM_{2.5}$), VOC, CO and HAP emissions estimates for the three auxiliary engines are based on AP-42, Section 3.4 emission factors (Table 3.4-1, Table 3.4-2, and Table 3.4-3). Non-methane VOC emission factor has been taken as 91% of the total organic compounds (TOC) emission factor. PM_{10} and $PM_{2.5}$ emission factors based on AP-42 Chapter 3, Table 3.4-2, Particulate and Particle-sizing Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996). An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr. PM < 3μm taken as $PM_{2.5}$. Total particulate emissions is the sum of filterable and condensable particulate emissions.

- **EPA Guidance Documents** – Lead emission factor is obtained from EPA's guidance document: *Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2*. Emission factor for distillate oil-fired gas turbines was used as a surrogate for distillate oil-fired engines due to unavailability of emission factors.

- **EPA Regulations –** CO_2, CH_4, and N_2O emission factors are obtained from 40 CFR 98 Subpart C, Table C-1 (Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel) and Table C-2 (Default CH_4 and N_2O Emission Factors for Various Types of Fuel). Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

- **IMO Tier I** – NO_x emissions estimates for the representative Auxiliary engines are based on IMO Tier I emission factors for an engine speed of 1,800 rpm. Speed of 1800 rpm is assumed based on other engines of comparable capacity and specifications.

- **Mass Balance** – Sulfur content of 0.1% is used for all diesel combustion sources per IMO standards for 2015. Therefore, SO_2 emissions are calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO_2 and 2 percent of sulfur in the fuel is oxidized to sulfuric acid (H_2SO_4) mist based on Section 4.1.1 of Draft Regulatory Impact Analysis: Control of Emissions

from Nonroad Diesel Engines, EPA420-R-03-008, April 2003. Emissions of Hydrogen sulfide (H_2S), total reduced sulfur (TRS), and reduced sulfur compounds resulting from sulfur content in the fuel are negligible.

Operating Parameters – The maximum hourly, daily, and annual emissions from the auxiliary engines are calculated based on the following operating parameters.

- **Maximum Hourly Emissions –** The maximum hourly emissions for the auxiliary engines are calculated based on simultaneous operation of all three engines at a brake horse power of 1609 HP at a conservative operating load of 60%. The selected emission factors used for these pollutants are shown in the emission calculations.

- **Maximum Daily Emissions –** The maximum daily emissions for the auxiliary engines are calculated based on 24 hours of operation per day.

- **Annual Emissions** – Annual emissions for the auxiliary engines have been conservatively calculated based on engine rate and an operating time of 4608 hours per year per engine. These operating hours are the same as used for the Carrier's main engine.

Miscellaneous Engines

Besides main and auxiliary engines, there are some miscellaneous engines on the Carrier, including Cargo Pumps, Stripping Pumps, Crane pumps, and Ballast Pumps.

Representative Cargo Pumps

Apolytares Q88 carrier has three Cargo pumps. The fuel consumption capacities are unknown for these pumps but a conservative estimate of 2250 HP is assumed. For emission estimation purposes, it is assumed that these operate for 24 hours a day and 4608 hours a year which is the same as the operating hours of the main engine. Emissions from these engines will result from combustion of diesel fuel in the engine. For a worst case emission scenario, it is assumed that these operate simultaneously at a 100% operating load.

Emissions Factors – The sources of emission factors used to estimate emissions for these engines are summarized below.

- **AP-42, Section 3.4. Large Stationary Diesel and All Stationary Dual-fuel Engines** – Particulate matter (PM, PM_{10}, and $PM_{2.5}$), NOx, CO, VOC, and HAP emissions estimates for these engines are based on AP-42, Section 3.4 emission factors (Table 3.4-1, Table 3.4-2, and Table 3.4-3). Non-methane VOC emission factor has been taken as 91% of the TOC emission factor. Total particulate emissions have been taken as the sum of filterable and condensable particulate emissions.

- **EPA Guidance Documents** – Lead emission factor is obtained from EPA guidance document: Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2. Emission factor for distillate oil-fired gas turbines was used as a surrogate for distillate oil-fired engines due to lack of emission factors.

- **EPA Regulations –** CO_2, CH_4, and N_2O emission factors are obtained from 40 CFR 98 Subpart C, Table C-1 (Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel) and Table C-2 (Default CH_4 and N_2O Emission Factors for Various Types of Fuel). Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

- **Mass Balance** – Sulfur content of 0.1% is used for all diesel combustion sources per IMO standards for 2015. Therefore, SO_2 emissions are calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO_2 and 2 percent of sulfur in the fuel is oxidized to H_2SO_4 mist based on Section 4.1.1 of Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003. Emissions of H_2S, TRS, and reduced sulfur compounds resulting from sulfur content in the fuel are negligible.

Operating Parameters – The maximum hourly, daily, and annual emissions from the emergency generator engine are calculated based on the following operating parameters.

- **Maximum Hourly Emissions** – The maximum hourly emissions for these engines are calculated based on simultaneous operation and engine brake horse power of 2250 HP at 100% load. The selected emission factors used for these pollutants as shown in the emission calculations.

- **Maximum Daily Emissions –** Maximum daily emissions for the cargo pump engines are calculated based on simultaneous operation for 24 hours, 2250 HP at 100% load.

Annual Emissions – Annual emissions for these engines have been conservatively calculated based on simultaneous operation, 2250 HP at 100% load, and an operating time of 4608 hours per year.

Representative Stripping Pump

Apolytares Q88 carrier consists of one Stripping pump. The fuel consumption capacities are unknown for these pumps but a conservative estimate of 180 HP is assumed. For emission estimation purposes, it is assumed that these operate for 24 hours a day and 4608 hours a year which is the same as the operating hours of the main engine. Emissions from these engines will result from combustion of diesel fuel in the engine. For a worst case emission scenario, it is assumed that this operates at a 100% operating load.

Emissions Factors – The sources of emission factors used to estimate emissions for these engines are summarized below.

- **AP-42, Section 3.4. Large Stationary Diesel and All Stationary Dual-fuel Engines** – Particulate matter (PM, PM_{10}, and $PM_{2.5}$), NOx, CO, VOC, and HAP emissions estimates for these engines are based on AP-42, Section 3.4 emission factors (Table 3.4-1, Table 3.4-2, and Table 3.4-3). Non-methane VOC emission factor has been taken as 91% of the TOC emission factor. Total particulate emissions have been taken as the sum of filterable and condensable particulate emissions.

- **EPA Guidance Documents** – Lead emission factor is obtained from EPA guidance document: Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2. Emission factor for distillate oil-fired gas turbines was used as a surrogate for distillate oil-fired engines due to lack of emission factors.

- **EPA Regulations –** CO_2, CH_4, and N_2O emission factors are obtained from 40 CFR 98 Subpart C, Table C-1 (Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel) and Table C-2 (Default CH_4 and N_2O Emission Factors for Various Types of Fuel). Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

- **Mass Balance** – Sulfur content of 0.1% is used for all diesel combustion sources per IMO standards for 2015. Therefore, SO_2 emissions are calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO_2 and 2 percent of sulfur in the fuel is oxidized

to H_2SO_4 mist based on Section 4.1.1 of Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003. Emissions of H_2S, TRS, and reduced sulfur compounds resulting from sulfur content in the fuel are negligible.

Operating Parameters – The maximum hourly, daily, and annual emissions from the emergency generator engine are calculated based on the following operating parameters.

- **Maximum Hourly Emissions** – The maximum hourly emissions for this engine is calculated based on engine brake horse power of 180 HP at 100% load. The selected emission factors used for these pollutants as shown in the emission calculations.

- **Maximum Daily Emissions –** Maximum daily emissions for the engine is calculated based on 24 hours of operation, 180 HP at 100% load.

- **Annual Emissions** – Annual emissions for this engine have been conservatively calculated based on 180 HP at 100% load, and an operating time of 4608 hours per year.

Representative Ballast Pumps

Apolytares Q88 carrier consists of two Ballast pumps. The fuel consumption capacities are unknown for these pumps but a conservative estimate of 1350 HP is assumed. For emission estimation purposes, it is assumed that these operate for 24 hours a day and 4608 hours a year which is the same as the operating hours of the main engine. Emissions from these engines will result from combustion of diesel fuel in the engine. For a worst case emission scenario, it is assumed that these operate simultaneously at a 100% operating load.

Emissions Factors – The sources of emission factors used to estimate emissions for these engines are summarized below.

- **AP-42, Section 3.4. Large Stationary Diesel and All Stationary Dual-fuel Engines** – Particulate matter (PM, PM_{10}, and $PM_{2.5}$), NOx, CO, VOC, and HAP emissions estimates for these engines are based on AP-42, Section 3.4 emission factors (Table 3.4-1, Table 3.4-2, and Table 3.4-3). Non-methane VOC emission factor has been taken as 91% of the TOC emission factor. Total particulate emissions have been taken as the sum of filterable and condensable particulate emissions.

- **EPA Guidance Documents** – Lead emission factor is obtained from EPA guidance document: Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2. Emission factor for distillate oil-fired gas turbines was used as a surrogate for distillate oil-fired engines due to lack of emission factors.

- **EPA Regulations –** CO_2, CH_4, and N_2O emission factors are obtained from 40 CFR 98 Subpart C, Table C-1 (Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel) and Table C-2 (Default CH_4 and N_2O Emission Factors for Various Types of Fuel). Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

- **Mass Balance** – Sulfur content of 0.1% is used for all diesel combustion sources per IMO standards for 2015. Therefore, SO_2 emissions are calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO_2 and 2 percent of sulfur in the fuel is oxidized to H_2SO_4 mist based on Section 4.1.1 of Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003. Emissions of H_2S, TRS, and reduced sulfur compounds resulting from sulfur content in the fuel are negligible.

Operating Parameters – The maximum hourly, daily, and annual emissions from the emergency generator engine are calculated based on the following operating parameters.

- **Maximum Hourly Emissions** – The maximum hourly emissions for these engines are calculated based on simultaneous operation and engine brake horse power of 1350 HP at 100% load. The selected emission factors used for these pollutants as shown in the emission calculations.

- **Maximum Daily Emissions –** Maximum daily emissions for the engines are calculated based on simultaneous operation for 24 hours, 1350 HP at 100% load.

Annual Emissions – Annual emissions for these engines have been conservatively calculated based on simultaneous operation, 1350 HP at 100% load, and an operating time of 4608 hours per year.

Representative Crane Engines

Apolytares Q88 carrier consists of two Cranes. The specifications of the crane equipment in this vessel are unavailable therefore specifications used are for a generic crane equipment with a Cummins VTA -1710-C700 diesel engine with a speed of 2000 RPM @ 685 HP. For emission estimation purposes, it is assumed that these operate for half the time or 12 hours on a daily basis and 4608 hours a year on an annual basis. Emissions from these engines will result from combustion of diesel fuel in the engine. For a worst case emission scenario, it is assumed that the two cranes operate at a 100% operating load simultaneously. It is also assumed that the crane engines operates under IMO Tier I standards for NOx.

Emissions Factors – The sources of emission factors used to estimate emissions for these engines are summarized below.

- **AP-42, Section 3.4. Large Stationary Diesel and All Stationary Dual-fuel Engines** – Particulate matter (PM, PM_{10}, and $PM_{2.5}$), CO, VOC, and HAP emissions estimates for these engines are based on AP-42, Section 3.4 emission factors (Table 3.4-1, Table 3.4-2, and Table 3.4-3). Non-methane VOC emission factor has been taken as 91% of the TOC emission factor. Total particulate emissions have been taken as the sum of filterable and condensable particulate emissions.

- **EPA Guidance Documents** – Lead emission factor is obtained from EPA guidance document: Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2. Emission factor for distillate oil-fired gas turbines was used as a surrogate for distillate oil-fired engines due to lack of emission factors.

- **IMO Tier I** – NO_x emissions estimates for the representative crane engine is based on IMO Tier I emission factors for an engine speed of 2000 rpm.

- **EPA Regulations –** CO_2, CH_4, and N_2O emission factors are obtained from 40 CFR 98 Subpart C, Table C-1 (Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel) and Table C-2 (Default CH_4 and N_2O Emission Factors for Various Types of Fuel). Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

- **Mass Balance** – Sulfur content of 0.1% is used for all diesel combustion sources per IMO standards for 2015. Therefore, SO_2 emissions are calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO_2 and 2 percent of sulfur in the fuel is oxidized to H_2SO_4 mist based on Section 4.1.1 of Draft Regulatory Impact Analysis: Control of Emissions from Nonroad

Diesel Engines, EPA420-R-03-008, April 2003. Emissions of H_2S, TRS, and reduced sulfur compounds resulting from sulfur content in the fuel are negligible.

Operating Parameters – The maximum hourly, daily, and annual emissions from the crane engines are calculated based on the following operating parameters.

- **Maximum Hourly Emissions** – The maximum hourly emissions for these engines are calculated based on engine brake horse power of 685 HP at 100% load. The selected emission factors used for these pollutants as shown in the emission calculations.

- **Maximum Daily Emissions –** Maximum daily emissions for the engines is calculated based on 12 hours of operation, 685 HP at 100% load.

Annual Emissions – Annual emissions for these engines have been conservatively calculated based on 685 HP at 100% load, and an operating time of 4608 hours per year.

Carrier Boiler

Carrier Boiler is a 3,407 Kg/hr on a Mitsubishi MAC-45 boiler present in Apolytares Q88 vessel. There are two boilers in this vessel but only one of them is used at any given time per the information received on June 16 2018 and the emissions from the boiler will result from combustion of diesel fuel. This boiler will be used a maximum total of 4608 hours per year with a maximum operating time of 24 hours per day. Fuel rate of 1064 gal per hour is based on the conversion factors of 1.88 lb/l of diesel and 0.26 gal/l. Other conversion factors such as 140 MMBTU/1000 gal are also used as referenced on AP-42 Section 1.3, Fuel Oil Combustion, Section 1.3.4.3, p. 1.3-8, 5/10.

Emissions Factors – The sources of emission factors used to estimate emissions for this boiler are summarized below.

- **AP-42 Section 1.3** – Particulate matter (PM, PM_{10}, and $PM_{2.5}$), NO_x, CO, VOC and HAP emissions are based on emission factors from AP-42 Section 1.3 - Fuel Oil Combustion, Table 1.3-1and Table 1.3-2, Emission Factors for No.2 fuel oil was used. Total particulate emissions is the sum of filterable and total condensable particulate emissions. SO_2 emission factor are adjusted for the weight % of sulfur in oil and was estimated based on usage of diesel as fuel containing 1000 ppm of Sulfur. Lead emission factors are based on AP-42 Section 1.3, Fuel Oil Combustion, Table 1.3-10, for Distillate fuel oil (p. 1.3-22,5/10).

- **EPA Regulations –** CO_2, CH_4, and N_2O emission factors are obtained from 40 CFR 98 Subpart C, Table C-1 (Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel) and Table C-2 (Default CH_4 and N_2O Emission Factors for Various Types of Fuel). Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

Operating Parameters – The maximum hourly, daily and annual emissions from the boilers are calculated based on the following operating parameters.

- **Maximum Hourly Emissions** – The maximum hourly emissions for the boiler is calculated based on maximum flow of 1064 gal/hr per boiler.

- **Maximum Daily Emissions** – The maximum daily emissions for the boiler is calculated based on 24 hour of operation and a maximum flow of 1064 gal/hr per boiler.

- **Annual Emissions** – Annual emissions for the boiler is calculated based on a maximum flow of 1064 gal/hr per boiler and an annual operating time of 4608 hours per year.

1.1.2.10.4 SUPPORT VESSELS

The associated support vessels proposed for this project will include a combination of tug boats and pilot boats. Tug boats will tug the carrier in the safety zone while the pilot boat will transport personnel to the carrier, as required for conducting the proposed project.

TGTI proposes to maintain the flexibility of utilizing any supply boat as long as it meets the criteria of equivalency specified in Section 3.1. While complying with mass emissions to demonstrate equivalency, TGTI proposes to use equal or lower emission for the entire boat and not on equipment by equipment basis.

Representative Tug Boats Combustion Sources
As it is presently not known which specific tug boat will be available during operation of this project and boats will be used interchangeably depending upon availability. TGTI proposes to use *a* representative tug boat vessel for estimating emissions. These boats have two main engines with a combined capacity of 6000-8000 HP. Total annual operating time of each boat is estimated at 3600 hours per year. These boats also have two auxiliary engines each with a rating of 100 HP each. All the engines will use diesel as the fuel. Details on calculation methodologies is explained below for the main and auxiliary engines.

Propulsion Main Engines 1 and 2

These boats use two main engines with a combined capacity of 6000 - 8000 HP. Representative commercial marine engines from Cummins are used. Cummins QSK60 models meet IMO 2 standards per the information on their website. The RPM is estimated at 1800 based on the Cummins HP data of similar engines. Information seen on the website as of 14 April 2018. Emissions are generated as a result of combustion of diesel fuel from the engines. Emissions estimation is based on a worse-case usage of 8000 HP.

Emissions Factors – The sources of emission factors used to estimate emissions for these engines are summarized below.

- **AP-42, Section 3.4. Large Stationary Diesel and All Stationary Dual-fuel Engines** – VOC and HAP emissions estimates for the engines are based on AP-42, Section 3.4 emission factors. Non methane VOC emission factor has been taken as 91% of TOC emission factor. A calculated heat rate of 19.16 MMBtu/hr was used to convert from lb/MMBtu to lb/hr to calculate emissions. Emission factor of $PM_{2.5}$ and PM_{10} are calculated based on ratio of $PM/PM_{2.5}$ and PM/PM_{10} which are obtained from AP-42 Chapter 3, Table 3.4-2. Total particulate emission factor used in the ratio has been taken as the sum of filterable and condensable particulate emissions.

- **40 CFR 94 Control of Emissions From Marine Compression-Ignition** - NO_x, emissions estimates for the main propulsion engines are based on 40 CFR 94 Marine Tier 2 exhaust emission standards. Equation used for EF determination is 44 X RPM ^ (-0.23).

- **EPA Guidance Documents** – Lead emission factor is obtained from EPA guidance document: Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2. Emission factor for distillate oil-fired gas turbines was used as a surrogate for distillate oil-fired engines due to lack of emission factors.

- **EPA Regulations** – CO_2, CH_4 and N_2O emission factors are obtained from 40 CFR 98 Subpart C, Table C-1(Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel) and Table C-2 (Default CH_4 and N_2O Emission Factors for Various Types of Fuel). Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

- **Mass Balance** – Sulfur content of 0.1% is used for all diesel combustion sources per IMO standards for 2015. Therefore, SO_2 emissions are calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO_2 and 2 percent of sulfur in the fuel is oxidized to H_2SO_4 mist based on Section 4.1.1 of Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003. Emissions of H_2S, TRS, and reduced sulfur compounds resulting from sulfur content in the fuel are negligible.

Operating Parameters – Per information provided by TGTI, the tug boats operate at a 30-50% operating load during normal operations when they are not tugging crude carriers. 90% of the operating load can be seen when tugging heavy load crude carriers. Daily and annual averages are based on the average load. The maximum hourly, daily and annual emissions from the engines are calculated based on the following operating parameters. A maximum of 8 crude carriers can load on any given month and it takes 2 days to load each carrier. Tug boats operate for 6 hours a day during this time. For maintenance related activities, tug boats operate for 8 hours a month. Based on this data, annual operating hours of 672 hours are calculated for tug boat activity in the safety zone when crude carriers are loaded or tugged. Both tug boats simultaneously operate at 90% load during this time. For the rest of the time or 2,928 hours, the tug boats are assumed to operate at 40% load. Blended time weighted operating load is calculated based on this data and that come out to be 49.33%.

- **Maximum Hourly Emissions** – Maximum hourly emissions for the two engines are calculated based on 8000 HP at a 90% operating load per engine. It is assumed that both the tug boats operate simultaneously during this time.

- **Maximum Daily Emissions** – Maximum daily emissions for the engines are calculated based on 8000 HP at an average operating load of 50.50% for 24 hours as a worst case scenario. It is assumed that both the tug boats operate simultaneously during this time.

- **Annual Emissions** –The annual emissions from main propulsion engines on the tug boats are calculated based on 3600 hrs/yr of operation at 8000 HP per engine per boat at an average operating load of 49.33%. It is assumed that both the tug boats operate simultaneously during this time.

Auxiliary Engines 1 and 2

As detailed in the last section, the auxiliary engines are 100 HP engines and there are 2 engines per boat. These are expected to operate at 3600 hours under an operating load of 60%. Emissions are generated as a result of combustion of diesel fuel from the engines. Average operating load of 60% is assumed as a conservative estimate.

Emissions Factors – The sources of emission factors used to estimate emissions for this engine are summarized below.

- **AP-42, Chapter 3, Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines (October 1996)** – VOC, and HAP emissions estimates for the engines are based on AP-42, Section 3.4 emission factors. Non methane VOC emission factor has been taken as 91% of TOC emission factor.

- **40 CFR 89.112(a) Table 1. Emission Standards. 75 kW Tier 2 engine -** Assumed that these engines are Tier II. Emission factors used for particulates, NOx and CO.

- **EPA Guidance Documents** – Lead emission factor is obtained from EPA guidance document: Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2. Emission factor for distillate oil-fired gas turbines was used as a surrogate for distillate oil-fired engines due to lack of emission factors.

- **EPA Regulations** – CO_2, CH_4 and N_2O emission factors are obtained from 40 CFR 98 Subpart C, Table C-1(Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel) and Table C-2 (Default CH_4 and N_2O Emission Factors for Various Types of Fuel). Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

- **Mass Balance** – Sulfur content of 0.1% is used for all diesel combustion sources per IMO standards for 2015. Therefore, SO_2 emissions are calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO_2 and 2 percent of sulfur in the fuel is oxidized to H_2SO_4 mist based on Section 4.1.1 of Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003. Emissions of H_2S, TRS, and reduced sulfur compounds resulting from sulfur content in the fuel are negligible.

Operating Parameters – The maximum hourly, daily and annual emissions from the engines are calculated based on the following operating parameters.

- **Maximum Hourly Emissions** – Maximum hourly emissions for the engines are calculated based on 100 HP at 60% load per engine.

- **Maximum Daily Emissions** – Maximum daily emissions for the engines are calculated based on 100 HP at 60% load for 24 hrs/day for each engine.

- **Annual Emissions** –The annual emissions from the auxiliary engines on the tug boats are calculated based on 3,600 hrs/yr of operation at 100 HP per engine per boat at an average operating load of 60%. It is assumed that both the tug boats operate simultaneously during this time.

Representative Pilot Boat Combustion Sources

As it is presently not known which specific pilot boat will be available during operation of this project and boats will be used interchangeably depending upon availability. TGTI proposes to use *a* representative pilot boat vessel for estimating emissions. This boat has a twin engine with a capacity of 750 HP. Total annual operating time of each boat is estimated at 1,728 hours per year which is ~50% of the operating hours for the tug boats. All the engines will use diesel as the fuel. Details on calculation methodologies is explained below for the twin engines.

The *pilot boat* consists of two 750 HP diesel-fired generator engines. Emissions are generated as a result of combustion of diesel fuel in the engines.

Emissions Factors – The sources of emission factors used to estimate emissions for these engines are summarized below.

- **AP-42, Section 3.4. Large Stationary Diesel and All Stationary Dual-fuel Engines** –Particulate matter (PM, PM_{10}, and $PM_{2.5}$), CO, VOC, and HAP emissions estimates for the engine are based on AP-42, Section 3.4 emission factors. Non methane VOC emission factor has been taken as 91% of TOC emission factor. Total particulate emissions have been taken as the sum of filterable and condensable particulate

emissions. An average BSFC of 7,000 Btu/hp-hr has been used to convert emission factors from lb/MMBtu to lb/hp-hr.

- **IMO Tier III** – NO_x emissions estimates for the representative pilot boat twin engine is based on IMO Tier III emission factors for an assumed engine speed of 1800 rpm. Equation used to arrive at EF is 9 X Speed (RPM) ^ (-0.2).

- **EPA Guidance Documents –** Lead emission factor has been obtained from EPA guidance document: *Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds*, EPA 454/R-98-006, May 1998, Section 5.2.2. Emission factor for distillate oil-fired gas turbines was used as a surrogate for distillate oil fired engines due to lack of emission factors.

- **Mass Balance** – Sulfur content of 0.1% is used for all diesel combustion sources per IMO standards for 2015. Therefore, SO_2 emissions are calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO_2 and 2 percent of sulfur in the fuel is oxidized to H_2SO_4 mist based on Section 4.1.1 of *Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines*, EPA420-R-03-008, April 2003. Emissions of H_2S, TRS, and reduced sulfur compounds resulting from sulfur content in the fuel are negligible.

- **EPA Regulations** – CO_2, CH_4 and N_2O emission factors are obtained from 40 CFR 98 Subpart C, Table C-1(Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel) and Table C-2 (Default CH_4 and N_2O Emission Factors for Various Types of Fuel). Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

Operating Parameters – The maximum hourly, daily and annual emissions from the twin engines have been calculated based on the following operating parameters:

Maximum Hourly Emissions – Maximum hourly emissions for the engines have been calculated based on 750 HP at 100% load per engine.

Maximum Daily Emissions – Maximum daily emissions for the engines have been calculated based on 750 HP at 100% load per engine and operating 12 hours per day.

Annual Emissions – Annual emissions estimates for engines on the pilot boat have been calculated based on operation of 1,728 hours per year for each engine.

EMERGENCY MANAGEMENT

Helicopter will be used to manage any emergency/safety situations related to any personnel operating in the safety zone. For emission estimation purposes 1 trip per week is assumed for a helicopter. As it is presently not known which helicopter will be available during operation of this project. TGTI proposes to use *a* representative helicopter for estimating emissions. It is assumed that for each landing take off cycle (LTO) of the helicopter takes about 2 hours.

Emissions are generated as a result of combustion of jet fuel for a twin engine medium lift.

Emissions Factors – The sources of emission factors used to estimate emissions for these engines are summarized below.

- **Year 2011 Gulfwide Emission Inventory Study (BOEM 2014-666)** – Emission factors for Criteria and GHG pollutants have been obtained from Table 6-12 Year 2011 Gulfwide Emission Inventory Study (BOEM 2014-666).

- **EPA Emission Factors** – HAP emission factors have been obtained from the "*Documentation for Aircraft Component of the National Emissions Inventory: Inventory Methodology USEPA, Emissions, Monitoring and Analysis Division, Contract No.: EP-D-07-097, April 23, 2010*". Only top five HAP emission factors used. All other HAPs emission factors a factor of 10 or more lower.

- **EPA Regulations** – Emission factor for CO_2e has been calculated using the GWPs obtained from 40 CFR 98 Subpart A.

Operating Parameters – The maximum hourly, daily and annual emissions from the twin engines have been calculated based on the following operating parameters:

Maximum Hourly Emissions – Maximum hourly emissions are based on one trip a day divided by the number of hours per trip, i.e. 2 hrs.

Maximum Daily Emissions – Maximum daily emissions are based on one trip a day.

Annual Emissions – Annual emissions estimates are based on 52 trips a year.

A summary of the annual emissions representations is provided in Table A-2 below. Detailed operational emissions calculations are provided at the end of this Appendix A (Tables A-10 through A-47).

Table A-2. Texas Gulf Terminal Project Normal Operation Annual Emissions (tpy)

Emission Unit ID	NSR Regulated Air Pollutants & Greenhouse Gas Emissions (CO_2e)										
	PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	H_2SO_4	CO	VOC	H_2S	Pb	CO_2e
	tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy
DWP Emissions Source for PSD Applicability											
Marine Loading[2]								10,808	0.24		
SPM Fugitive[2]								0.22			
Indirect Emission Sources											
Tug Boat - Supply Boat Main Engines	9.94	5.70	5.53	183.29	10.62	0.33	78.14	9.11		0.003	16,271
Tug Boat Aux Engine	0.21	0.21	0.21	4.69	0.32	0.01	3.55	1.09		0.000	495
Pilot Boats	0.91	0.52	0.50	4.28	0.97	0.03	7.13	0.83		0.000	1,484
Helicopter	0.00	0.00	0.00	0.05	0.01	0.00	0.14	0.10		0.000	11
Carrier Main Engine	27.57	27.57	25.34	728.02	16.95	0.53	65.95	14.54		0.005	25,955
Carrier Aux Engine	4.67	2.68	2.60	110.26	4.99	0.16	36.71	4.28		0.001	5,096
Crane Engine	2.21	1.27	1.23	51.06	2.36	0.07	17.36	2.03		0.001	3,615
Carrier Boiler	8.09	8.09	8.09	58.83	34.81	0.00	12.26	0.49		0.003	56,146
Cargo Pumps	10.89	6.24	6.05	373.25	11.63	0.36	85.54	9.98		0.003	17,812
Stripping Pumps	0.29	0.17	0.16	9.95	0.31	0.01	2.28	0.27		0.000	475
Ballast Pumps	4.35	2.50	2.42	149.30	4.65	0.15	34.21	3.99		0.001	7,125
TOTAL Normal Operation Scenario (Worse Case)	**69.1**	**54.9**	**52.1**	**1673.0**	**87.6**	**1.65**	**343**	**10,855**	**0.24**	**0.02**	**134,484**

1.2.2.12 Onshore Required Permits

For compliance with the abovementioned laws and regulations, the OSTF may be required to obtain the following permits prior to construction and operation:

- TCEQ Booster Station – NSRP
- TCEQ Valve Station - Deminimis

1.2.2.13 Onshore Existing Threats

Existing threats to onshore air quality include both commercial and private sources. The project area is located in a non-industrial rural area, consisting of the series of tanks and pipelines necessary to receive, store, measure, and transport crude oil to the DWP. Vehicle traffic, both private and commercial, also contribute to emissions in the area.

[2] Marine Loading and SPM Fugitive are DWP Emission Sources for PSD Applicability. Rest of them are indirect emission sources.

1.2.2.14 Onshore Existing Conditions

Existing conditions, including onshore regional climate, existing ambient air quality, and greenhouse gasses and climate change are discussed in the following subsections.

1.2.2.15 Onshore Regional Climate

The location for the proposed onshore tank farm is Kleberg County, Texas. The Golf Cost of Texas can be classified as having a warm, humid climate with hot summers (Köppen-Geiger climate classification Cfa) (NOAA 2017). Historic data from Corpus Christi International Airport, indicate a mean daily temperature ranging from 84.2°F in August to 55°F in January, with mean daily highs ranging up to 94°F in August, and mean daily lows ranging down to 45.3°F in January. Mean annual precipitation is 32 inches, distributed relatively evenly throughout the year (NOAA 2017).

The entire Gulf of Mexico and its coastal areas are subject to tropical storms and hurricanes, which are most likely to occur between late May and early November. On average, the proposed Project area will experience a tropical storm (sustained winds of at least 39 miles per hour, or 17 m/s) every 1 or 2 years, while a hurricane (sustained winds of at least 74 miles per hour, or 33 m/s) can be expected to cross the proposed Project area once every 4 to 5 years. A "major" hurricane rated as Category 3 or higher (sustained winds of at least 110 miles per hour, or 50 m/s) may occur about once every 25 years. Along the coastal locations, heavy rains and wind-driven storm surges may cause local or widespread flooding

1.2.2.16 Onshore Existing Ambient Air Quality

Kleberg County is currently classified as an attainment or unclassified area for all criteria pollutants. Currently, there are no active monitoring stations for NO_2 located in in Kleberg County.[3] Therefore, Texas Gulf Terminals Inc. selected the Channelview Monitor, EPA Site Number 48-201-0026, located in Harris County near Houston, Texas as the conservative/representative monitor for the OSTF NO_2 background concentrations. Additionally, TGTI selected the Corpus Christi Dona Park Monitor, EPA Site Number 48-355-0034 (Dona Park Monitor), as the representative monitor for the OSTF for SO_2 and $PM_{2.5}$ background concentrations. Further information pertaining to the criteria's used to determine the monitoring stations are provided in the modeling report included in Appendix C of this license application. The monitoring values shown in Table A-1 are for the 3-year period of 2014 through 2016.

1.2.2.17 Onshore Greenhouse Gas Regulations

New sources that trigger PSD for one or more criteria pollutants are also required to apply GHG BACT if GHG emissions exceed the GHG PSD Tailoring threshold. The proposed onshore operations will not qualify as a major PSD source for a criteria pollutant, thus the proposed onshore operations are not required to evaluate GHG BACT.

1.2.2.18 Onshore Operation Emissions

The storage tanks at the onshore tank farm terminal will handle sweet crude oil/condensate with a maximum True Vapor Pressure (TVP) of 11 psia. The site will receive these products via up to four (4) bi-directional pipelines (inbound and outbound). Two (2) outbound pipelines will also be utilized. The products will be stored in internal floating roof (IFR) tanks. The proposed terminal will store the products within twelve (12) IFR tanks. A 250,000 bbl internal floating roof tank will be used to store either Slop Oil or the crude/condensate product. Fugitive emissions will be emitted from piping connections and components throughout the onshore tank farm. The onshore tank farm will also include one (1) emergency firewater pump, one (1) Oil Water Separator and one (1) diesel tank. A summary of the proposed emissions is provided in the Table below.

[3] Information Obtained from EPA's Air Data website and TCEQ's Geo TAM website.

Planned periodic maintenance will be performed on the proposed storage tanks at the site. The onshore TGTI Terminal will include a vapor combustion unit (VCU) to combust emissions from standing idle, degassing and refilling maintenance activities and a carbon control unit to control sludge removal and vacuum truck venting activities. The VCU will operate using pipeline quality natural gas fuel. Tank MSS activities as associated with forced ventilation will be vented directly to the atmosphere. Planned pipeline MSS activities will also be performed at the site and will include activities such as pipeline pigging. All piping MSS emissions will be vented directly to the atmosphere. A summary of the proposed MSS emissions is provided in the Table below.

Table A-3. Summary of Emissions at the Onshore Tank Farm

EPN / Emission Sources	VOC tpy	NO_x tpy	CO tpy	PM tpy	PM_{10} tpy	$PM_{2.5}$ tpy	SO_2 tpy
IFR Tanks TK-501-512; Slop Oil and FWP Diesel Tank	87.75	0.00					
FWP-1, OWS and Emergency Generator[4]	0.45	1.01	0.95	0.06	0.06	0.06	0.002
Fugitives FUG-100 - FUG-400	6.17						
MSS Activities	0.85	0.13	0.25	0.01	0.01	0.01	0.003
Totals	**95.22**	**1.14**	**1.20**	**0.07**	**0.07**	**0.07**	**0.005**

The booster station near the TGTI Terminal (TGTI Booster Station) will have one (1) new 300-barrel horizontal tank (EPN D-TK) to store cleaning materials resulting from pigging and pump manifold clearing operations; and Fugitive components (EPN FUG). A summary of the proposed emissions is provided in the Table below.

Table A-4. Summary of Emissions at the Onshore Booster Station

EPN / Emission Source	VOC tpy
D-TK / Day Tank	2.99
FUG / Fugitives	1.73
Totals	**4.71**

For further details on the proposed emissions calculations for the OSTF terminal, please refer to Appendix F included in this license application.

[4] The emergency generator is authorized under PBR 106.511 and is not included as part of this Non-Rule Standard Permit.

1.2.3 Decommissioning

1.2.3.1 Impacts of Decommissioning

Proposed Project decommissioning would result in comparable emissions to those described for the construction process; however, impacts would be of a lesser extent in both duration and extent. Impacts associated with proposed Project decommissioning would be expected to be short-term, and negligible.

During decommissioning, the proposed pipelines and SPM, would be abandoned in-place to be consistent with current Federal policies to minimize impacts. Minor air emissions are anticipated for these activities.

1.3. ALTERNATIVES ANALYSIS

Pursuant to NEPA, governmental decision-makers must consider reasonable alternatives to a proposed action that could result in significant environmental effects. To be reasonable, the alternatives must:

- Satisfy the proposed project's basic purpose and need;
- Avoid or substantially lessen a project's potential effects;
- Be technically and economically feasible and practical; and
- Can meet the proposed project's objectives.

Identifying and evaluating alternatives helps to ensure that decisions concerning the license are well founded and, as required by the DWPA, are in the nation's best interest, and that they are consistent with national security, energy sufficiency, and environmental quality policy goals and objectives.
Section 2 presents a range of reasonable alternatives to the proposed action in accordance with the requirements of NEPA. These requirements; however, do not call for the consideration of every possible alternative; rather, only a reasonable number of examples, covering the full spectrum of alternatives. This analysis focuses on reasonable alternatives, even if these alternatives are not within the capability of the Applicant or could be costlier. The alternatives evaluation considers energy source alternatives, as well as siting and system technology alternatives.

The selected range of alternatives is intended to facilitate meaningful discussion among decision- makers and the public regarding the best means to satisfy the need for providing a safe and reliable facility to export crude product to FTA and non-FTA nations, particularly U.S. allies subject to unreliable crude oil supplies due to political instability in certain regions of the world.

1.3.1 Alternatives Analysis Methodology

The scope of the proposed project is to build an SPM buoy system fed by subsea pipelines located offshore at a depth where very large crude oil carriers (VLCCs) can be loaded directly. As such, the SPM buoy system will be located about 15 miles offshore at a water depth of approximately 93 feet. The depth is critical to the proposed project because it will allow the VLCCs to be fully loaded and still navigate the waters safely. The capacity to fully load VLCCs offshore with crude oil via subsea pipelines does not currently exist off the shores of the United States. Loading VLCCs offshore via subsea pipelines represents a more efficient and safer option to alternative methods of fully loading VLCCs near shore, partially loading VLCCs near shore and supplementing with loading from other smaller tanker/carriers, or solely utilizing smaller carriers to ultimately conduct Ship-to-Ship (STS) transfers / lightering operations.

The main alternative to the proposed SPM buoy system is lightering operations. Lightering is the process of loading smaller tanker vessels (which can navigate the shallower waters near shore) onshore and then loading the VLCCs with the smaller vessels offshore at a suitable depth. While TGTI is analyzing lightering as an alternative to the proposed SPM buoy system for completeness of the alternatives analysis in this section, TGTI does not believe lightering to be a suitable alternative to the proposed SPM buoy system because the SPM buoy system is being proposed in place of already-common lightering operations.

To determine the alternative scenario TGTI used monthly available data for VLCCs completely loaded offshore in the lightering zone via STS transfers and VLCCs partially loaded onshore with the remainder loaded offshore in the lightering zone via STS transfers. Based on monthly data for VLCC loading to date in 2018, over 90% of crude oil loaded to VLCCs was loaded completely via STS transfers in the offshore lightering zone and less than 10% of crude oil loaded to VLCCs was loaded through partial loading onshore with the remainder of the VLCC loaded offshore in the lightering zone via STS transfers. The alternative lightering scenario (relative to proposed SPM

Design) quantifying the comparable air emissions generated from VLCC loading through complete lightering and partial lightering is explained below:

- Complete Lightering - VLCC Completely Loaded Offshore
  - Three (3) AFRAMAX carriers are loaded onshore, travel 65 miles[5] to the lightering zone, and unload via STS transfers into the VLCC;
- Partial Lightering - VLCC Partially Loaded Inland, Remainder Loaded by Lightering Offshore
  - VLCC travels inland, loads up to 50% capacity inland; VLCC travels to lightering zone, Suezmax vessels loaded onshore, Suezmax vessels travel 65 miles[1] to lightering zone and unload via STS transfers into the VLCC filling the remaining 50% of the VLCC offshore.

The capacities of these tankers are summarized below.

Vessel/Carrier	Deadweight (tons)	Capacity (bbls)[6]
AFRAMAX	100,000	750,000
SUEZMAX	160,000	1,000,000

Lightering creates additional emissions compared to the proposed SPM buoy system because material is first transferred onshore into the smaller vessels before ultimately being loading from the smaller vessels onto the VLCCs (Ship-to-Ship [STS] transfers). There are inherent emissions generated by the smaller ships during the lightering process and control requirements do not apply to the STS transfer of product to VLCCs during lightering operations. In contrast, the proposed SPM buoy system will utilize electric pumps located onshore to transport the product offshore through the SPM buoy system for loading to the VLCC. Lightering operations cause environmental impact from the initial loading onshore, transit of the lightering vessel out to the VLCC, STS transfer to the VLCC, and return transit of the lightering vessel back to shore. Loading of the lightering vessels onshore is assumed to be controlled by a vapor combustor that achieves 99% control efficiency and is assumed to have a 99% capture efficiency[7].

The emission sources considered for this analysis are listed below:

- Crude carrier, Support Vessels & Boats
- Lightering Vessel Loading
- Lightering Vessel Transfer/Transit
- Lightering Vessel Propulsion
- Tugs/Support Ships

Operating scenarios and emission calculation rationale for these sources is summarized below with details shown in the emission calculation tables.

<u>Complete Lightering: VLCC Completely Loaded Offshore</u>

The various emission sources represented are described below.

[5] The shortest distance between the shore and SPM location is 15 miles but the distance travelled is not straight and estimated to be 65 miles one way.
[6] Based on http://alloiltank.com/oil-tanker-ship/.
[7] Control efficiency as represented for other onshore terminals and also per current TCEQ policy. Capture efficiency was obtained from "Air Permits Division Marine Loading Collection Efficiency Guidance (September 21, 2016)."

- **Crude carrier, Support Vessels & Boats** – The operating scenarios and emissions are assumed to be the same as is the current proposed design involving the loading of VLCC at the SPM Buoy and support operations.

- **Lightering Loading** – The emissions are based on loading of crude or condensate from the AFROMAX vessels to the VLCC as discussed in the alternative operation scenarios listed above. Annual maximum loading rate of 192 million BBL/ year is used for emission estimation. Onshore VOC emissions are based on an aggregate of uncaptured fugitive emissions and controlled captured emissions. Emissions from combustion byproducts of the onshore control device are shown for NOx, CO, SO_2 and particulates. HAP emissions are based on the product of the crude speciation profile wt. percent and VOC emissions.

- **Lightering Transit** – In addition to loading losses, losses occur while the cargo is in transit. Transit losses are similar to breathing losses associated with petroleum storage. Transit time is estimated at 14.5 hrs or 0.60 days one way. Emissions are uncontrolled. HAP emissions are based on the product of the crude speciation profile wt. percent and VOC emissions.

- **Lightering Vessel Propulsion –** The engine rating data of the AFROMAX engines are not available and therefore assumed based on the (carrying capacity of the vessels) X (rating of the VLCCs used for proposed design) / (carrying capacity of the VLCC). Operating time assumed to be the same as the travel time (14.5 hrs one way). Calculations are based on a round-trip and a factor of 50% is added in for time spent during loading/unloading when the engine is running. Operating load is estimated based on the following calculation - (25% x 7 hrs + 90% x 14.5 hrs + 40% x 14.5 hrs)/(36 hrs) where 25% of the operated load happens during loading/unloading operations, 90% of the load when the carrier is travelling and full with crude; and 40% when its making a trip back and is empty. The emission factors for particulates, NOx, and CO are based on Crude Carrier emission factors from Table 6-1 Year 2011 Gulfwide Emission Inventory Study (BOEM 2014-666) for Commercial Marine Vessels for Diesel. No HAPs emission factors reported. VOC emission factor is based on AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996). SO_2 and H_2SO_4 emission factors are based on the fuel sulfur content and have been calculated based on a maximum sulfur content of 1000 ppm (IMO 2015 standards) in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO_2 and 2 percent of sulfur in the fuel is oxidized to H_2SO_4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

- **Tugs/Support Ships** – The lightering scenario assumes that one additional tug boat is needed for servicing the AFRAMAX with operating conditions similar to the tug boats proposed for normal operation. Please review the normal operation calculations for tug-boats for additional details.

Partial Lightering - VLCC Partially Loaded Inland, Remainder Loaded by Lightering Offshore

The emission sources for this lightering operation are described below.

- **Crude Carrier, Support Vessels & Boats** – The operating scenarios and emissions are assumed to be the same as is the current proposed design involving the loading of VLCC at the SPM Buoy and support operations.

- **Lightering Loading** – The emissions are based on loading of crude or condensate from the SUEZMAX vessel to the VLCC offshore in an STS transfer and direct loading of crude or condensate from the shore to VLCC for up to 50% of its capacity. A total annual maximum loading rate of 192 million BBL/ year is used for emission estimation. VOC loading emissions are based on an aggregate of uncaptured fugitive

emissions and controlled captured emissions for onshore loading operations. Emissions from combustion byproducts of the onshore control device are shown for NOx, CO, SO_2 and particulates. HAP emissions are based on the product of the crude speciation profile wt. percent and the VOC emissions.

- **Lightering Transit** – In addition to loading losses, losses occur while the cargo is in transit. Transit losses are similar to breathing losses associated with petroleum storage. For this lightering scenario, VLCCs come inland and load to 50% (partial) capacity and then travel offshore to have the remaining product loaded via STS transfer at an offshore lightering location. One (1) SUEZMAX vessel loads inland and then travels to the lightering location to fill the remaining 50% of the VLCC via STS transfer offshore. Transit time is assumed to be 14.5 hrs or 0.60 days one way. Emissions for STS transfer lightering are uncontrolled. HAP emissions are based on the product of the crude speciation profile wt. percent and the VOC emissions.

- **Lightering Vessel Propulsion –** The engine rating data of the SUZEMAX engines are not available and therefore assumed based on the (carrying capacity of the vessels) X (rating of the VLCCs used for proposed design) / (carrying capacity of the VLCC). Operating time assumed to be the same as the travel time (14.5 hrs one way). Calculations are based on a round-trip and a factor of 50% is added in for time spent during loading/unloading when the engine is running. The operating load is estimated based on the following calculation - (25% x 7 hrs + 90% x 14.5 hrs + 40% x 14.5 hrs)/(36 hrs) where 25% of the operated load happens during loading/unloading operations, 90% of the load when the carrier is travelling and full with crude; and 40% when its making a trip back and is empty. The emission factors for particulates, NOx, and CO are based on Crude Carrier emission factors from Table 6-1 Year 2011 Gulfwide Emission Inventory Study (BOEM 2014-666) for Commercial Marine Vessels for Diesel. No HAPs emission factors reported. VOC emission factor is based on AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996). SO_2 and H_2SO_4 emission factors are based on the fuel sulfur content and have been calculated based on a maximum sulfur content of 1000 ppm (IMO 2015 standards) in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO_2 and 2 percent of sulfur in the fuel is oxidized to H_2SO_4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

- **Tugs/Support Ships** – This lightering scenario assumes that one additional tug boat is needed for servicing the SUEZMAX and VLCC with operating conditions similar to the tug boats proposed for normal operation. Please review the normal operation calculations for tug-boats for additional details.

1.3.2 Alternatives Analysis Emission Comparison

The lightering scenario emissions are expected to be higher than the proposed SPM buoy system fed by subsea pipelines. As demonstrated in the emission comparison plots and comparison table below, the proposed SPM buoy system will not only have a lower environmental impact compared to lightering operations (as discussed below) but it will also present a more efficient, logistically simplified, and safer approach to crude exports from the United States. It is for these reasons that TGTI asserts the proposed SPM buoy system is favorable to the proposed alternative of lightering operations. Comparison of these emissions to the proposed design are shown below. Detailed calculations can be seen on tables A-48 through A-55.

Table A-5. Emission comparison of alternative (lightering) to current proposed design

Alternative Analysis Emissions Comparison	VOC	NO_x	CO	PM	SO_2	HAPs	CO_2e	Totals (Criteria and CO_2e)
Lightering	13,279	3,136	579	127	125	248	251,871	269,179
Proposed SPM Design	10,855	1,673	343	69	88	201	134,484	147,515
Emissions Reduction from Proposed SPM Design	**2,424**	**1,463**	**236**	**58**	**37**	**47**	**117,387**	**121,663**

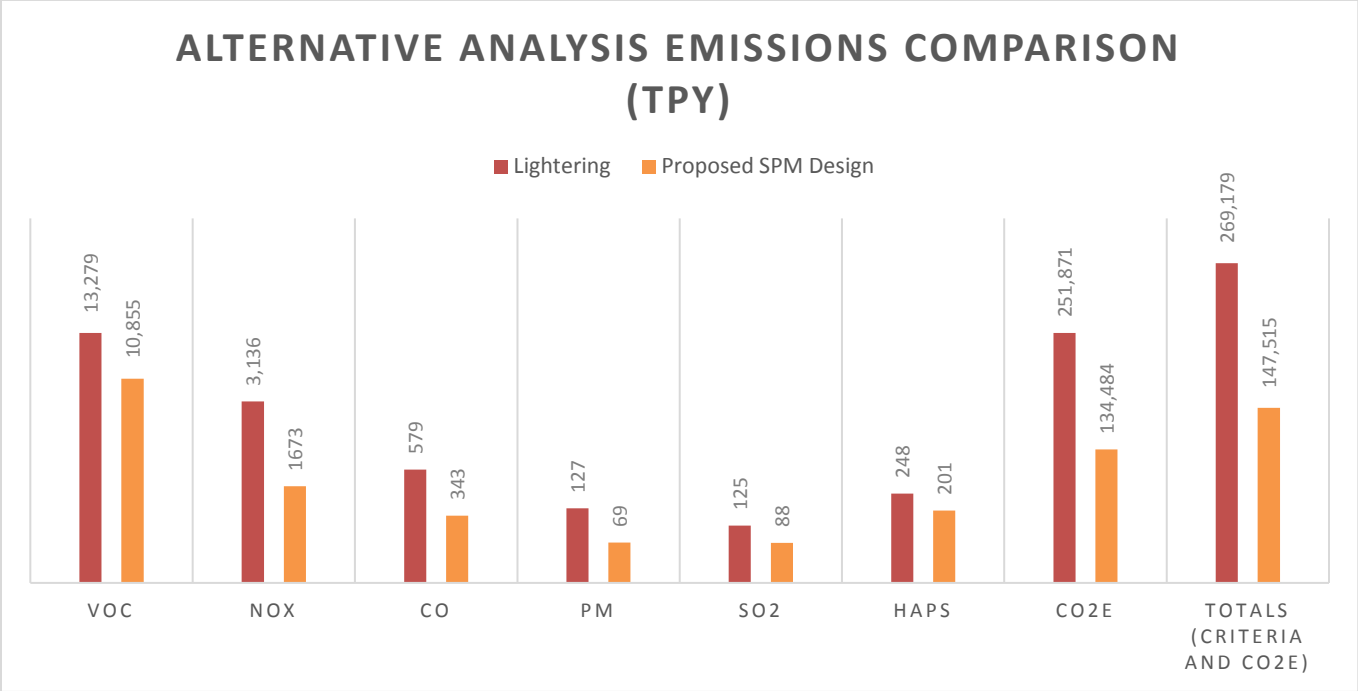

Table A-6. Construction Phase Emissions Summary
Table A-7. Commute Emissions
Table A-8. Fugitive Dust Emissions
Table A-9. Factors and Conversions
Table A-10. Normal Operations Annual Emission Summary
Table A-11. Normal Operations Hourly Emission Summary
Table A-12. Normal Operations Daily Emission Summary
Table A-13. Loading Emissions-Criteria
Table A-14. Loading Emissions – HAP
Table A-15. SPM Fugitive Emissions
Table A-16. Tug Boats Main - Criteria
Table A-17. Tug Boats Main - HAP
Table A-18. Tug Boats Main - GHG
Table A-19. Tug Boat Aux Engine - Criteria
Table A-20. Tug Boat Aux Engine - HAP
Table A-21. Tug Boat Aux Engine - GHG
Table A-22. Pilot Boats - Criteria
Table A-23. Pilot Boats - HAP
Table A-24. Pilot Boats - GHG
Table A-25. Helicopter Emissions
Table A-26. Carrier Main Engine - Criteria
Table A-27. Carrier Main Engine - HAP
Table A-28. Carrier Main Engine - GHG
Table A-29. Carrier Aux Engine - Criteria
Table A-30. Carrier Aux Engine- HAP
Table A-31. Carrier Aux Engine - GHG
Table A-32. Crane Engine - Criteria
Table A-33. Crane Engine - HAP
Table A-34. Crane Engine - GHG
Table A-35. Carrier Boiler - Criteria
Table A-36. Carrier Boiler - HAP
Table A-37. Carrier Boiler - GHG
Table A-38. Cargo Pumps - Criteria
Table A-39. Cargo Pumps - HAP
Table A-40. Cargo Pumps - GHG
Table A-41. Stripping Pump - Criteria
Table A-42. Stripping Pump - HAP
Table A-43. Stripping Pump - GHG
Table A-44. Ballast Pumps - Criteria
Table A-45. Ballast Pumps - HAP
Table A-46. Ballast Pumps - GHG
Table A-47. SO2 EF Calculation
Table A-48. Alternatives Lightering Analysis Summary
Table A-49. Lightering Loading-Criteria
Table A-50. Lightering Loading-HAP
Table A-51. Transit Emissions-Criteria
Table A-52. Transit Emissions - HAP
Table A-53. Propulsion Engine - Criteria
Table A-54. Propulsion Engine - GHG
Table A-55. Propulsion Engine - HAP

CONSTRUCTION PHASE EMISSION CALCULATIONS

Tables A-6 to A-9

Texas Gulf Terminals Inc.
Construction Activities Emissions Summary for Pipeline and SPM Installation

Operations	Equipment / Source	Equipment Model Type / Description	Rating (UOM)		Max Fuel/ Operating Load (UOM)		Run Time [12]		Number of Units	Factors/UOM	EF and Adjustment Factors									Max (lb/Hr)									Estimated (tpy)								
							Hrs/D	Days			PM	NO_X	SO_2	CO	VOC	CO_2	CH_4	N_2O	CO_2e [5]	PM	NO_X	SO_2	CO	VOC	CO_2 [3]	CH_4 [4]	N_2O [4]	CO_2e [5]	PM	NO_X	SO_2	CO	VOC	CO_2 [3]	CH_4 [4]	N_2O [4]	CO_2e [5]
Layout Pipe and Weld above Ground; Pipeline Crossings, Special Sections and Tie-Ins	Welding, Combustion Emissions	Unavailable [7]	8.5	HP	100	%	12	154.00	9	Emission Factor (g/hp-hr) [1] [3] [4]	1.00E+00	1.00E+01	5.38E-03	5.00E+00	1.50E+00	2.50E+02	1.42E-02	6.30E-03		3.56E-01	2.21E+00	1.17E-03	2.72E+00	7.99E-01	4.21E+01	2.39E-03	1.06E-03	42.48	0.329	2.041	0.001	2.509	0.739	38.91	0.002	0.001	39.25
										In-use Adjustment Factor [2]	2.11	1.31	1.29	3.22	3.16	1.00	1.00	1.00		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Pipelay Barge	Unavailable [7] [9]	3300	HP	100	%	12	154.00	2	Emission Factor (lb/hp-hr for PM, SO2, CO, VOC, g/KW-hr for NOx, and Kg/MMBTU for GHG) [9] [5]	7.00E-04	7.85E+00	7.48E-04	5.50E-03	6.42E-04	7.40E+01	3.00E-03	6.00E-04		4.62E+00	8.52E+01	4.94E+00	3.63E+01	4.23E+00	7.53E+03	3.06E-01	6.11E-02	7558.93	4.269	78.680	4.560	33.541	3.912	6960.57	0.282	0.056	6984.45
	Generator	Unavailable [7]	17	HP	100	%	12	154.00	3	Emission Factor (g/hp-hr) [1] [3] [4]	1.00E+00	1.00E+01	5.38E-03	5.00E+00	1.50E+00	2.50E+02	1.42E-02	6.30E-03		2.37E-01	1.47E+00	7.81E-04	1.81E+00	5.33E-01	2.81E+01	1.59E-03	7.08E-04	28.32	0.219	1.361	0.001	1.673	0.492	25.94	0.001	0.001	26.17
										In-use Adjustment Factor [2]	2.11	1.31	1.29	3.22	3.16	1.00	1.00	1.00		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Excavate Trench and Installation of Pipe	Excavators	CATERPILLAR 235 (excavator) [6]	200	HP	100	%	12	154.00	6	Emission Factor (g/hp-hr) [1] [3] [4]	4.00E-01	8.38E+00	4.86E-03	2.70E+00	6.80E-01	2.50E+02	1.42E-02	6.30E-03		9.42E-01	1.93E+01	1.33E-02	3.14E+00	2.52E+00	6.60E+02	3.75E-02	1.67E-02	666.39	0.870	17.822	0.012	2.904	2.327	610.29	0.035	0.015	615.74
										In-use Adjustment Factor [2]	0.89	0.87	1.03	0.44	1.40	1.00	1.00	1.00		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Side-Booms	CATERPILLAR PL87 sideboom [7]	240	HP	100	%	12	154.00	4	Emission Factor (g/hp-hr) [1] [3] [4]	4.00E-01	8.38E+00	4.86E-03	2.70E+00	6.80E-01	1.86E+02	1.06E-02	4.71E-03		1.09E+00	1.74E+01	1.02E-02	8.57E+00	1.27E+00	3.94E+02	2.24E-02	9.98E-03	397.55	1.009	16.060	0.009	7.920	1.170	364.07	0.021	0.009	367.34
										In-use Adjustment Factor [2]	1.29	0.98	0.99	1.50	0.88	1.00	1.00	1.00		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	HDD Rig	N/A [8]	300	HP	100	%	12	154.00	1	Emission Factor (g/hp-hr) [1] [3] [4]	4.00E-01	8.38E+00	4.86E-03	2.70E+00	6.80E-01	1.86E+02	1.06E-02	4.71E-03		5.48E-01	5.82E+00	3.73E-03	4.75E+00	1.00E+00	1.23E+02	7.01E-03	3.12E-03	124.23	0.506	5.377	0.003	4.389	0.927	113.77	0.006	0.003	114.79
										In-use Adjustment Factor [2]	2.07	1.05	1.16	2.66	2.23	1.00	1.00	1.00		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Pulling Winch	Unavailable [13]	320	HP	100	%	12	154.00	3	Emission Factor (g/hp-hr) [1] [3] [4]	4.00E-01	8.38E+00	4.86E-03	2.70E+00	6.80E-01	1.86E+02	1.06E-02	4.71E-03		1.09E+00	1.74E+01	1.02E-02	8.57E+00	1.27E+00	3.94E+02	2.24E-02	9.98E-03	397.55	1.009	16.060	0.009	7.920	1.170	364.07	0.021	0.009	367.34
										In-use Adjustment Factor [2]	1.29	0.98	0.99	1.50	0.88	1.00	1.00	1.00		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Support Vessel for Rig Pullback, other operations	Unavailable [14]	1500	HP	100	%	24	154.00	2	Emission Factor (lb/hp-hr for PM, SO2, CO, VOC, g/KW-hr for NOx, and Kg/MMBTU for GHG) [14] [5]	7.00E-04	2.01E+00	7.48E-04	5.50E-03	6.42E-04	7.40E+01	3.00E-03	6.00E-04		2.10E+00	9.91E+00	2.24E+00	1.65E+01	1.92E+00	3.42E+03	1.39E-01	2.78E-02	3435.88	3.881	18.320	4.145	30.492	3.557	6327.79	0.257	0.051	6349.50
	Shallow Water Barge	Unavailable [11]	100	HP	100	%	24	154.00	1	Emission Factor (lb/hp-hr for Criteria, and Kg/MMBTU for GHG) [11] [5]	4.93E-04	1.09E-02	7.48E-04	8.22E-03	2.51E-03	7.40E+01	3.00E-03	6.00E-04		4.93E-02	1.09E+00	7.48E-02	8.22E-01	2.51E-01	1.14E+02	4.63E-03	9.26E-04	114.53	0.091	2.005	0.138	1.519	0.465	210.93	0.009	0.002	211.65
	Contractor's Crane	Crane 250 ton [15]	625	HP	100	%	24	154.00	1	Emission Factor (g/hp-hr) [1] [3] [4]	4.00E-01	8.38E+00	4.86E-03	2.70E+00	6.80E-01	1.86E+02	1.06E-02	4.71E-03		7.11E-01	1.13E+01	6.63E-03	5.58E+00	8.25E-01	2.57E+02	1.46E-02	6.50E-03	258.82	1.314	20.912	0.012	10.313	1.524	474.05	0.027	0.012	478.30
										In-use Adjustment Factor [2]	1.29	0.98	0.99	1.50	0.88	1.00	1.00	1.00		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Installation of SPM and Components	SPM Installation tug boats	Main and Aux Engines [10]	9000	HP	100	%	24	133.00	2	Emission Factor (lb/hp-hr for PM, SO2, CO, VOC, g/KW-hr for NOx, and Kg/MMBTU for GHG) [14] [5]	7.00E-04	2.01E+00	7.48E-04	5.50E-03	6.42E-04	7.40E+01	3.00E-03	6.00E-04		1.26E+01	5.95E+01	1.35E+01	9.90E+01	1.15E+01	2.05E+04	8.33E-01	1.67E-01	20615.27	20.110	94.929	21.481	158.004	18.430	32789.45	1.330	0.266	32901.97
	Air Compressor	Unavailable [7]	120	HP	100	%	24	14.00	2	Emission Factor (g/hp-hr) [1] [3] [4]	1.00E+00	1.00E+01	4.84E-03	5.00E+00	1.50E+00	2.50E+02	1.42E-02	6.30E-03		1.12E+00	6.93E+00	3.30E-03	8.52E+00	2.51E+00	1.32E+02	7.50E-03	3.33E-03	133.28	0.188	1.164	0.001	1.431	0.421	22.19	0.001	0.001	22.39
										In-use Adjustment Factor [2]	2.11	1.31	1.29	3.22	3.16	1.00	1.00	1.00		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydraulic Power Pack - 400 Ton Crane		778	HP	100	%	24	133.00	2	Emission Factor (g/hp-hr) [1] [3] [4]	4.00E-01	8.38E+00	4.86E-03	2.70E+00	6.80E-01	1.86E+02	1.06E-02	4.71E-03		1.77E+00	2.82E+01	1.65E-02	1.39E+01	2.05E+00	6.39E+02	3.64E-02	1.62E-02	644.37	2.825	44.962	0.026	22.173	3.276	1019.26	0.058	0.026	1028.41
										In-use Adjustment Factor [2]	1.29	0.98	0.99	1.50	0.88	1.00	1.00	1.00		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Testing and Commissioning	Dive boat/vessel	Unavailable [14]	1500	HP	100	%	12	154.00	1	Emission Factor (lb/hp-hr for PM, SO2, CO, VOC, g/KW-hr for NOx, and Kg/MMBTU for GHG) [14] [5]	7.00E-04	2.01E+00	7.48E-04	5.50E-03	6.42E-04	7.40E+01	3.00E-03	6.00E-04		1.05E+00	4.96E+00	1.12E+00	8.25E+00	9.62E-01	1.71E+03	6.94E-02	1.39E-02	1717.94	0.970	4.580	1.036	7.623	0.889	1581.95	0.064	0.013	1587.38
Miscellaneous activities	Pumps	Pressure Washer/Blast Cleaning Pumps [15]	50	HP	100	%	12	154.00	5	Emission Factor (g/hp-hr) [1] [3] [4]	1.00E+00	1.00E+01	5.38E-03	5.00E+00	1.50E+00	2.50E+02	1.42E-02	6.30E-03																			
										In-use Adjustment Factor [2]	2.11	1.31	1.29	3.22	3.16	1.00	1.00	1.00																			
	Fugitives	Fugitive dust (onshore construction)								Details can be seen on the Fugitive Dust Calculations table										4.92									9.90								
	Pick-up Trucks	Commuting Activities								Details can be seen on the Commute Calculations table										8.82E-04	1.71E-01	2.07E-01	2.13E+00	2.20E-01	2.68E+02	2.19E+01	3.96E-03	817.13	0.001	0.158	0.191	1.970	0.204	247.69	20.250	0.004	755.03
TOTALS																				33.20	270.73	22.11	220.56	31.91	36265.32	23.42	0.34	36952.67	47.49	324.43	31.63	294.38	39.50	51150.92	22.36	0.47	51849.71

Notes

[1] Emission factors from "*Exhaust Emission Factors for Nonroad Engine Modeling --Compression Ignition* ", Report No. NR-009A, revised June 15, 1998, US EPA Office of Mobile Sources.

Steady-state emissions factors for CI engines obtained from Table 1, assuming 1988-99 model year engines, not subject to Tier 1 or Tier 2 controls.
SO_2 emission factor based on break-specific fuel consumption (BSFC) given in Table 1 and assuming default sulfur content of 15 ppm for ULS
SO2 EF = (BSFC * 453.6* (1 - 0.022) - HC) *) * 15/1000000 * 2; where 453.6 is the conversion factor from pounds to grams; 1-0.022 is an adjustment for sulfur converted to direct PM; HC is the in-use adjusted hydrocarbon emissions in g/hp-hr; ULSD is used for construction equipment except for vessels that comply with IMO 2015 standards. 15 ppm is used as Sulfur weight fraction for ULSD while 1000 ppm is used for IMO 2015 standards. 2 is the grams of SO2 formed from a gram of sulfur.

[2] In-use adjustment factors obtained from "*Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling -- Compression Ignition, Table F-3* ",

Report No. NR-009d, revised July 2010, US EPA Office of transportation and Air Quality.

[3] CO_2 emission factor was obtained from USEPA "*Direct Emissions from Mobile Combustion Sources, May 2008, EPA430-K-08-004;*

Table B-1: Factors for Calculating CO2 Emissions from Motor Gasoline and Diesel Fuel Use".

[4] CH_4 and N_2O emission factors are obtained from USEPA "*Direct Emissions from Mobile Combustion Sources, May 2008, EPA430-K-08-004; Table A-6. CH_4 and N_2O Emission Factors for Non-Highway Vehicles*".

[5] CH_4, CO_2, and N_2O are included in the emissions of CO2 equivalent (CO_2e), weighted according to their global warming potentials (GWP). The GWP of CH_4 is 25, of CO_2 is 1, and of N_2O is 298.

[6] Engine Rating and operating hours data provided by TGT. The counts include the Amphibious as well as regular Excavators.

[7] Engine Rating, counts and operating hours data provided by TGT.

[8] Specifications assumed as data not available. Assumed operating hours to be twice as of the excavators. Counts of equipment are provided by TGT.

[9] Pipelay Barge - SO2 emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel (per IMO 2015 standards) assuming that 98 percent of sulfur in the fuel is oxidized to SO2 and 2 percent of sulfur in the fuel is oxidized to H2SO4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.
For NOx emissions, Cummins QSK60 models are assumed. They meet IMO 2 standards per the information on their website. The RPM is estimated at 1800 based on the Cummins HP data of similar engines. Information seen on the website on 14 April 2018.
CO and VOC Emission factors are based on AP-42, Section 3.4 emission factors. PM emission factors based on AP-42 Chapter 3, Table 3.4-2, Particulate and Particle-sizing Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996). An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr.
For GHG, Emission factor based on 40 CFR 98 Subpart C, Table C-1 and C-2 Default CO2, CH4, N2O Emission Factors and High Heat Values for Various Types of Fuel.

[10] Per the information received from TGT, Two tug boats @ 8000 HP main engines and 500 HP Aux engines operate at full capacity for 19 weeks 24 hrs a day.
Emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel (per IMO 2015 standards) assuming that 98 percent of sulfur in the fuel is oxidized to SO2 and 2 percent of sulfur in the fuel is oxidized to H2SO4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.
For NOx emissions, it is assumed that the engines meet IMO 3 standards. The RPM is estimated at 1800 based on the Cummins HP data of similar engines. Information seen on the website on 14 April 2018.
CO and VOC Emission factors are based on AP-42, Section 3.4 emission factors. PM emission factors based on AP-42 Chapter 3, Table 3.4-2, Particulate and Particle-sizing Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996). An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr.
For GHG, Emission factor based on 40 CFR 98 Subpart C, Table C-1 and C-2 Default CO2, CH4, N2O Emission Factors and High Heat Values for Various Types of Fuel.

[11] Barge(s) or Work Platform(s) for HDD Rig and HDD support in shallow water (<6' water depth) - Emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel (per IMO 2015 standards) assuming that 98 percent of sulfur in the fuel is oxidized to SO2 and 2 percent of sulfur in the fuel is oxidized to H2SO4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.
For NOx emissions, EFs obtained from 40 CFR 89.112(a) Table 1. Emission Standards. 75 kW Tier 2 engine. Assumed that these engines are Tier II. PM, and CO factors are based on 40 CFR 89.112.
Other Criteria Emission factors are based on AP-42, Chapter 3, Table 3.3-1, Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines (October 1996). Emission factors for diesel fuel are used. All TOC is assumed to be VOC. TOC emission factor has been calculated as the sum of exhaust and crankcase emission factors.
For GHG, Emission factor based on 40 CFR 98 Subpart C, Table C-1 and C-2 Default CO2, CH4, N2O Emission Factors and High Heat Values for Various Types of Fuel.

[12] Maximum length of construction assumed to be 154 days based on information received from TGT.

[13] Specifications assumed as data not available. Assumed operating hours to be the same as of the side-booms. Counts of equipment are provided by TGT.

[14] Assumed to operate for 22 weeks; 24 hrs a day on support vessel and 12 hours a day on the diving boat. HP assumed based on combined capacity of twin engines.
Emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel (per IMO 2015 standards) assuming that 98 percent of sulfur in the fuel is oxidized to SO2 and 2 percent of sulfur in the fuel is oxidized to H2SO4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.
For NOx emissions, it is assumed that the engines meet IMO 2 standards for pipelay barge and IMO 3 standards for support vessel. The RPM is estimated at 1800 based on the Cummins HP data of similar engines. Information seen on the website on 14 April 2018.
CO and VOC Emission factors are based on AP-42, Section 3.4 emission factors. PM emission factors based on AP-42 Chapter 3, Table 3.4-2, Particulate and Particle-sizing Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996). An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr.
For GHG, Emission factor based on 40 CFR 98 Subpart C, Table C-1 and C-2 Default CO2, CH4, N2O Emission Factors and High Heat Values for Various Types of Fuel.

[15] Specifications assumed as data not available. Assumed operating hours to be the same as the project length. Counts of equipment assumed.

Sample Calculations:

Total Emissions

Total Estimated Emissions (tpy) = Operating hrs/day x Number of days x Hourly Emissions (lb/hr) / 2000 lb/ton; Sample PM tpy emissions = 12 hrs/day x 154 days x 0.3559 lb/hr /2000 lb/ton = 0.3288 tpy

Hourly Emission Calculations using the emission factors in g/hp-hr and adjustment factors -

Max LB/HR Emissions = Rating (HP) x Number of Units x EF (g/hp-hr) x Adjustment Factor x Capacity (%) x 0.00220462 g/lb; Sample PM lb/hr emissions = 8.5 hp x 9 x 1 g/hp-hr x 2.11 x 100% x 0.00220462 g/lb = 0.3559 lb/hr

Hourly Emission Calculations using the emission factors in lb/hp-hr for PM, SO2, CO, VOC, g/KW-hr for NOx, and Kg/MMBTU for GHG

Pipelay Barge Max LB/HR Emissions (PM) = 0.0007 lb/hp-hr x 2 x 3300 HP x 100% = 4.62 lb/hr

Pipelay Barge Max LB/HR Emissions (NOx) = 7.84766 g/kw-hr x 2 x 3300 HP x 100% / 453.59 g/lb /1.341 = 85.1514 lb/hr

Max CO2 LB/HR Emissions (Pipelay Barge) = 3300 HP x 2.20462 Lb/Kg 73.96 Kg/MMBTU /1000000 x 7000 Btu/hp-hr x 2 x 100% = 7533 lb/hr

Hourly Fugitive Dust Emission Calculations

PM Emissions (lb/hr) = Emissions (tpy) x 2000 lb/ton / Construction time-line (month) / (30.5 days/month) / (24 hours/day) = 9.9 x 2000 / 5.5/ 30.5/ 24 = 4.918 lb/hr

Hourly GHG Emission Calculations

Pipelay Barge CO2e (lb/hr) = 7533 lb/hr CO2 x 1 + 0.306 lb/hr CH4 x 25 + 0.061 lb/hr N2O x 298 = 7558.93 lb/h

Indirect Emissions from Construction Workers Commuting during Construction phase (22 weeks)
Emissions represent construction worker commuting onshore for pipeline and SPM installation activities
Workers commuting are based on Light Duty Gasoline Trucks (LDGT)

Emission Factor

Vehicle Type			PM [1]		NO_X [1]		VOC [1]		CO [1]		SO_2 [5]		CO_2 [2],[3]			CH_4 [4]		N_2O [4]	
			(g/mile)	(g/trip)	(g/mile)	(g/trip)	(g/mile)	(g/trip)	(g/mile)	(g/trip)	(g/mile)	(g/trip)	(Kg/gal)	(gal/mile)	(g/trip)	(g/mile)	(g/trip)	(g/mile)	(g/trip)
Workers Commuting (LDGT)	Miles per Vehicle Trip per day	15	0.0049	0.07	0.950	14.25	1.224	18.36	11.84	177.60	1.15E+00	17.23	8.81	0.17	22333	0.200	3.00	0.0220	0.33
Onshore Construction Related Travel	Miles per day per truck	20	0.0049	0.10	0.950	19.00	1.224	24.48	11.84	236.80	1.15E+00	22.98	8.81	0.17	29778	0.200	4.00	0.0220	0.44

Construction Workers Commuting Frequency

Construction Duration	22 Weeks	Number of Commuting Trips (round-trip)	Number of Work Trips
Number of FTE	60	9240	616
Number of Work Pick-up Trucks	4		

Note: FTE (Full-time equivalent) is based on 60 hours/week. As a result, it was assumed that the staff work 7 days per week

Commuting Emission Calculations - Annual [6]

Vehicle Type	Number of Trips	Annual Emission (tpy)								
		NO_X	VOC	CO	SO2	PM	CO_2	N_2O	CH_4	CO_2e
Workers Commuting (LDGT)	9240	0.15	0.19	1.81	0.176	0.00	227	0.00	0.03	229
Onshore Construction Related Travel	616	0.01	0.02	0.16	0.02	0.00	20.22	0.00	20.22	526
Totals	**9856**	**0.16**	**0.20**	**1.97**	**0.19**	**0.00**	**247.69**	**0.00**	**20.25**	**755.03**

Commuting Emission Calculations - Average Hourly [6]

Vehicle Type	Number of Trips	Hourly Emission (lb/hr)								
		NO_X	VOC	CO	SO2	PM	CO_2	N_2O	CH_4	CO_2e
Totals	**9856**	**0.17**	**0.22**	**2.13**	**0.21**	**0.00**	**268.06**	**0.00**	**21.92**	**817.13**

Notes:
[1] Emission factors for LDGT are obtained from USEPA Fact Sheet "Average Annual Emissions and Fuel Consumption for Gasoline-Fueled Passenger Cars and Light Trucks".

[2] CO_2 Emission factors are obtained from USEPA *"Direct Emissions from Mobile Combustion Sources, May 2008, EPA430-K-08-004; Table 5. Factors for Gasoline and On-Road Diesel Fuels"*.

[3] Fuel economy values are obtained from USEPA *"Direct Emissions from Mobile Combustion Sources, May 2008, EPA430-K-08-004; Table 4. Fuel Economy Values by Vehicle Type"*.
[4] CH_4 and N_2O Emission factors are obtained from USEPA *"Direct Emissions from Mobile Combustion Sources, May 2008, EPA430-K-08-004; Table 2. CH_4 and N_2O Emission Factors for Highway Vehicles"* .
Emission factors for uncontrolled sources were used.
[5] SO_2 emission factors are obtained from *"USEPA AP-42 Chapter 3.3-Gasoline and Diesel Industrial Engines, Table 3.3-1.* Emissions were calculated based on assumptions that the vehicles would be travelling at 35 mph and LDGT are of 150 hp.
[6] Hourly Emissions are based on 12 hour work-days and annual emissions are based on 22 weeks of daily commute activities

Sample Calculations:

SO2 EF (g/mile) = (5.91E-4 lb/ hp-hr) x 150 hp x (453.59 g/lb) / (35 mile/hr) = 1.15 g/mile
Annual Emissions (tpy) = Number of Trips x EF (g/trip) / 453.6 gm/lb / 2000 lb/ton; NOx emissions (lb/hr) = 9240 x 14.25 g/trip / 453.6 / 2000 = 0.15 tpy
Hourly Emissions (lb/hr) = Annual Emissions (tpy) x 2000 lb/ton / 22 weeks / 7 days/week / 12 hours/day; NOx emissions (lb/hr) = 0.15 tpy x 2000 / 22 / 7 / 12 = 0.17 lb/hr

Fugitive Dust

Facility	Land Affected by Construction [1]	Duration	Control Efficiency [3]	TSP Emissions [2]			PM10 [4]			PM2.5 [4]		
				Emission Factor	Emission Rate		Adjustment Factor	Emission Rate		Adjustment Factor	Emission Rate	
	(acres)	(Months)	(%)	(ton/acre/month)	(tons)	(tpy)		(tons)	(tpy)		(tons)	(tpy)
Onshore Construction Area	3	6	50%	1.20	9.90	21.60	0.50	4.95	10.80	0.075	0.74	1.62

Notes:
[1] The total acreage of the construction site is assumed to be 3 acres.
[2] Emissions based on an EPA emission factor of 1.2 tons/acre/month of activity from Section 13.2.3 of AP-42. Emission factor is most applicable to a semiarid climate; therefore, calculated emissions should exceed those for the actual site. Emissions listed are upper bound estimates for fugitive total suspended particulates (TSP) generated by construction activities.
[3] Emissions assume a 50% control due to application of dust suppressants.
[4] PM10 and PM2.5 emissions calculated using ratios from AP-42 Section 13.2.5.3.

Sample Calculations:

Emissions = (emission factor) x (affected area) x (duration of activity) x (50% control)

EF Conversions and References

Sulfur Diesel - SO_2 Emission Factor Calculation - Mass Balance

Sulfur Content of Diesel[1]	Conversion Factor	Density of Diesel[2]	Diesel Heat Value[3]	Engine Efficiency[4]	Conversion of S in fuel to SO_2 in exhaust[5]		SO_2 Emission Factor IMO 2015	
1000	0.98	7.05	1.00	7,000	64.1	=	7.48E-04	1.07E-01
ppm S	lb of S	lb of diesel	gal. of diesel	btu	lb/lb-mol of SO_2		lb	lb
	1.00E+06	1	129,226.50	1	32.1		1	1
	lb of diesel - ppm S	gal. of diesel	btu	hp-hr	lb/lb-mol of S		hp-hr	MMBtu

Sulfur Content of Diesel[1]	Conversion Factor	Density of Diesel[2]	Diesel Heat Value[3]	Engine Efficiency[4]	Conversion of S in fuel to SO_2 in exhaust[5]		SO_2 Emission Factor ULSD	
15	0.98	7.05	1.00	7,000	64.1	=	1.12E-05	1.60E-03
ppm S	lb of S	lb of diesel	gal. of diesel	btu	lb/lb-mol of SO_2		lb	lb
	1.00E+06	1	129,226.50	1	32.1		1	1
	lb of diesel - ppm S	gal. of diesel	btu	hp-hr	lb/lb-mol of S		hp-hr	MMBtu

[1] Sulfur content of 0.1% is based on IMO 2015 standards for vessels and other sources subject to this standard. Others are assumed to use ULSD (15 ppm Sulfur).
[2] AP-42, Appendix A, Page A-7.
[3] Heating value is obtained from Chevron Diesel Fuels Technical Review Table 4.3.
[4] AP-42, Table 3.4-1, footnote e.
[5] Per Section 4.1.1 of *Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines* , EPA420-R-03-008, April 2003,
98% of sulfur in the fuel is assumed to be converted into SO_2.

Sulfur Diesel - H_2SO_4 Emission Factor Calculation - Mass Balance

Sulfur Content of Diesel[1]	Conversion Factor	Density of Diesel[2]	Diesel Heat Value[3]	Engine Efficiency[4]	Conversion of S in fuel to H_2SO_4 in exhaust[5]		H_2SO_4 Emission Factor IMO 2015	
1000	0.02	7.05	1.00	7,000	98.1	=	2.34E-05	3.34E-03
ppm S	lb of S	lb of diesel	gal. of diesel	btu	lb/lb-mol of H_2SO_4		lb	lb
	1.00E+06	1	129,226.50	1	32.1		1	1
	lb of diesel - ppm S	gal. of diesel	btu	hp-hr	lb/lb-mol of S		hp-hr	MMBtu

Sulfur Content of Diesel[1]	Conversion Factor	Density of Diesel[2]	Diesel Heat Value[3]	Engine Efficiency[4]	Conversion of S in fuel to H_2SO_4 in exhaust[5]		H_2SO_4 Emission Factor ULSD	
15	0.02	7.05	1.00	7,000	98.1	=	3.50E-07	5.01E-05
ppm S	lb of S	lb of diesel	gal. of diesel	btu	lb/lb-mol of H_2SO_4		lb	lb
	1.00E+06	1	129,226.50	1	32.1		1	1
	lb of diesel - ppm S	gal. of diesel	btu	hp-hr	lb/lb-mol of S		hp-hr	MMBtu

[1] Sulfur content of 0.1% is based on IMO 2015 standards for vessels and other sources subject to this standard. Others are assumed to use ULSD (15 ppm Sulfur).
[2] AP-42, Appendix A, Page A-7.
[3] Heating value is obtained from Chevron Diesel Fuels Technical Review Table 4.3.
[4] AP-42, Table 3.4-1, footnote e.
[5] Per Section 4.1.1 of *Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines* , EPA420-R-03-008, April 2003, 2
% of sulfur in the fuel is conservatively assumed to be converted into H_2SO_4.

GHG EF Conversions for Engines

Direct Emissions from Mobile Combustion Sources, Table B-1, May 2008, EPA430-K-08-004, [1]

CO2	UOM	Table B-1		CH4	Table A-6	N2O	
19.95	Kg C/MMBTU	43.98245111	Lb C/MMBTU	0.18	G/KG	0.08	G/KG
12	C Mol Wt	3.665204259		5.825	MMBtu/bbl	5.825	MMBtu/bbl
44	CO2 Mol Wt	161.2689874	Lb CO2/MMBTU	0.138690476	MMBtu/gal	0.1386905	MMBtu/gal
0.45359	lb/Kg	73.15		40.63630952	kW-hr/gal	40.63631	kW-hr/gal
293	KW/MMBTU	73150		3.2	kg/gal	3.2	kg/gal
		249.6587031	**g/kW-hr**	12.69884673	KW-Hr/Kg	12.698847	KW-Hr/Kg
				0.014	**g/kW-hr**	**0.006**	**g/kW-hr**

[1] http://large.stanford.edu/courses/2013/ph240/cabrera2/docs/epa-430-k-08-004.pdf

NORMAL OPERATIONS EMISSION CALCULATIONS

Tables A-10 to A-47

Texas Gulf Terminals Inc.
Normal Operations Emissions Summary - Crude Carrier, Support Vessels & boats

Annual Emissions Summary (tons/year)

Emission Unit ID	Emission Unit	NSR Regulated Air Pollutants & Greenhouse Gas Emissions (CO_2e)											Hazardous Air Pollutants (HAPs)
		PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	H_2SO_4	CO	VOC	H_2S	Pb	CO_2e	Total VOC HAPs
		tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr
DWP Emissions Source for PSD Applicability													
Marine Loading	Marine Loading								10,808	0.24			2.00E+02
SPM Fugitive	SPM Fugitive								0.22				
Indirect Emission Sources													
Tug Boat - Supply Boat Main Engines	Tug Boat - Supply Boat Main Engines	9.94	5.70	5.53	183.29	10.62	3.32E-01	78.14	9.11		2.88E-03	16,271	1.69E-01
Tug Boat Aux Engine	Tug Boat Aux Engine	0.21	0.21	0.21	4.69	0.32	1.01E-02	3.55	1.09		8.77E-05	495	1.20E-02
Pilot Boats	Pilot Boats	0.91	0.52	0.50	4.28	0.97	3.03E-02	7.13	0.83		2.63E-04	1,484	1.55E-02
Helicopter	Helicopter	0.00	0.00	0.00	0.05	0.01	0.00E+00	0.14	0.10		0.00E+00	11	6.90E-02
Carrier Main Engine	Carrier Main Engine	27.57	27.57	25.34	728.02	16.95	5.29E-01	65.95	14.54		4.60E-03	25,955	2.70E-01
Carrier Aux Engine	Carrier Aux Engine	4.67	2.68	2.60	110.26	4.99	1.56E-01	36.71	4.28		1.35E-03	5,096	5.31E-02
Crane Engine	Crane Engine	2.21	1.27	1.23	51.06	2.36	7.37E-02	17.36	2.03		6.41E-04	3,615	3.77E-02
Carrier Boiler	Carrier Boiler	8.09	8.09	8.09	58.83	34.81	0.00E+00	12.26	0.49		3.09E-03	56,146	1.69E-01
Cargo Pumps	Cargo Pumps	10.89	6.24	6.05	373.25	11.63	3.63E-01	85.54	9.98		3.16E-03	17,812	1.86E-01
Stripping Pumps	Stripping Pumps	0.29	0.17	0.16	9.95	0.31	9.69E-03	2.28	0.27		8.42E-05	475	4.95E-03
Ballast Pumps	Ballast Pumps	4.35	2.50	2.42	149.30	4.65	1.45E-01	34.21	3.99		1.26E-03	7,125	7.42E-02
TOTAL Normal Operation Scenario (Worst Case)		**69.1**	**54.9**	**52.1**	**1673.0**	**87.6**	**1.65E+00**	**343.3**	**10,855**	**0.24**	**1.74E-02**	**134,484**	**201.1**

Texas Gulf Terminals Inc.
Normal Operations Emissions Summary - Crude Carrier, Support Vessels & boats

Hourly Emissions Summary (lbs/hr)

Emission Unit ID	Emission Unit	NSR Regulated Air Pollutants & Greenhouse Gas Emissions (CO_2e)											Hazardous Air Pollutants
		PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	H_2SO_4	CO	VOC	H_2S	Pb	CO_2e	Total VOC HAPs
		lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr
DWP Emissions Source for PSD Applicability													
Marine Loading	Marine Loading								7,774	0.17			1.25E+02
SPM Fugitive	SPM Fugitive								0.05				
Indirect Emission Sources													
Tug Boat - Supply Boat Main Engines	Tug Boat - Supply Boat Main Engines	10.08	5.78	5.60	185.78	10.77	0.34	79.20	9.24		0.00	9,040	1.72E-01
Tug Boat Aux Engine	Tug Boat Aux Engine	0.12	0.12	0.12	2.60	0.18	0.01	1.97	0.60		0.00	275	6.65E-03
Pilot Boats	Pilot Boats	1.05	0.60	0.58	4.96	1.12	0.04	8.25	0.96		0.00	1,718	1.79E-02
Helicopter	Helicopter	0.03	0.03	0.03	0.98	0.15	0.00	2.67	2.01		0.00	212	1.33E+00
Carrier Main Engine	Carrier Main Engine	11.97	11.97	11.00	315.98	7.35	0.23	28.62	6.31		0.00	11,265	1.17E-01
Carrier Aux Engine	Carrier Aux Engine	2.03	1.16	1.13	47.86	2.17	0.07	15.93	1.86		0.00	2,212	2.30E-02
Crane Engine	Crane Engine	0.96	0.55	0.53	22.16	1.02	0.03	7.54	0.88		0.00	1,569	1.63E-02
Carrier Boiler	Carrier Boiler	3.51	3.51	3.51	25.53	15.11	0.00	5.32	0.21		0.00	24,369	7.33E-02
Cargo Pumps	Cargo Pumps	4.73	2.71	2.63	162.00	5.05	0.16	37.13	4.33		0.00	7,731	8.05E-02
Stripping Pumps	Stripping Pumps	0.13	0.07	0.07	4.32	0.13	0.00	0.99	0.12		0.00	206	2.15E-03
Ballast Pumps	Ballast Pumps	1.89	1.08	1.05	64.80	2.02	0.06	14.85	1.73		0.00	3,092	3.22E-02
TOTAL Normal Operation Scenario (Worst Case)		**36.48**	**27.58**	**26.25**	**836.97**	**45.07**	**0.93**	**202.46**	**7,802**	**0.17**	**0.01**	**61,689**	**126.90**

Texas Gulf Terminals Inc.
Normal Operations Emissions Summary - Crude Carrier, Support Vessels & boats

Daily Emissions Summary (lbs/day)

Emission Unit ID	Emission Unit	NSR Regulated Air Pollutants & Greenhouse Gas Emissions (CO_2e)											Hazardous Air Pollutants
		PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	H_2SO_4	CO	VOC	H_2S	Pb	CO_2e	Total VOC HAPs
		lbs/d	lbs/d	lbs/d	lbs/d	lbs/d	lbs/d	lbs/d	lbs/d	lbs/d	lbs/d	lbs/d	lbs/d
DWP Emissions Source for PSD Applicability													
Marine Loading	Marine Loading								59,221	1.30	0.00	0	1.10E+03
SPM Fugitive	SPM Fugitive								1.21				
Indirect Emission Sources													
Tug Boat - Supply Boat Main Engines	Tug Boat - Supply Boat Main Engines	132.60	75.98	73.73	2443.95	141.64	4.42	1041.85	121.53		0.04	216,950	2.26E+00
Tug Boat Aux Engine	Tug Boat Aux Engine	2.84	2.84	2.84	62.50	4.31	0.13	47.35	14.48		0.00	6,597	1.60E-01
Pilot Boats	Pilot Boats	12.60	7.22	7.01	59.48	13.46	0.42	99.00	11.55		0.00	20,615	2.15E-01
Helicopter	Helicopter	0.06	0.06	0.06	1.95	0.29	0.00	5.33	4.01		0.00	424	2.66E+00
Carrier Main Engine	Carrier Main Engine	287.20	287.20	263.91	7583.55	176.52	5.51	686.94	151.45		0.05	270,369	2.82E+00
Carrier Aux Engine	Carrier Aux Engine	48.66	27.88	27.06	1148.58	51.98	1.62	382.35	44.60		0.01	53,079	5.53E-01
Crane Engine	Crane Engine	11.51	6.59	6.40	265.96	12.29	0.38	90.42	10.55		0.00	18,829	1.96E-01
Carrier Boiler	Carrier Boiler	84.26	84.26	84.26	612.79	362.57	0.00	127.66	5.11		0.03	584,852	1.76E+00
Cargo Pumps	Cargo Pumps	113.40	64.98	63.05	3888.00	121.13	3.78	891.00	103.93		0.03	185,537	1.93E+00
Stripping Pumps	Stripping Pumps	3.02	1.73	1.68	103.68	3.23	0.10	23.76	2.77		0.00	4,948	5.15E-02
Ballast Pumps	Ballast Pumps	45.36	25.99	25.22	1555.20	48.45	1.51	356.40	41.57		0.01	74,215	7.73E-01
TOTAL Normal Operation Scenario (Worst Case)		**741.51**	**584.73**	**555.21**	**17,725.63**	**935.87**	**17.90**	**3,752.06**	**59,733**	**1.30**	**0.19**	**1,436,414**	**1,109.49**

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Marine Loading (DWP Emissions Source for PSD Applicability)
Criteria Pollutants

Hourly and Annual VOC Emissions Estimates for Loading of Crude Oil and Condensate

Hourly Loading Emissions

Liquid Loaded [1]	Saturation Factor [2]	Maximum Temp [3] (°F)	Maximum Temp [3] (°R)	Vapor MW (lb/lb mol)	Maximum True Vapor Pressure (TVP) [4] (psia)	Arrival Emission Factor [5] (lb/1,000 gal)	Generated Emission Factor [6] (lb/1,000 gal)	Uncontrolled Loading Loss [7] (lb/1,000 gal)	TOC to VOC Factor	Hourly Loading Rate [8] (bbl/hr)	Uncontrolled VOC Hourly Emissions [9] (lb/hr)
Crude Oil	0.2	73.50	533.17	50	11.00	--	--	2.57	1.00	60,000	6,478.07
Condensate	0.2	73.50	533.17	60	11.00	--	--	3.08	1.00	60,000	7,773.68

[1] For hourly emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.
[2] Saturation factor for marine loading obtained from U.S. EPA 42, Section 5.2 (1/95), Table 5.2-1.
[3] Maximum of monthly average liquid surface temperature was used .
[4] Maximum true vapor pressure for Crude oil and Condensate obtained from information provided by Texas Gulf Terminals
[5] Arrival emission factor for crude/condensate loading obtained from U.S. EPA 42, Section 5.2 (1/95), Table 5.2-3.
[6] Generated emission factor is calculated using equation 3 from U.S. EPA 42, Section 5.2 (1/95).
[7] Uncontrolled Loading Loss (lb/1,000 gal) = 12.46 x Saturation Factor x Maximum TVP of Liquid Loaded (psia) x Vapor MW (lb/lbmol) / Maximum Temperature of Bulk Liquid Loaded (°R)

$$\text{Crude Oil Uncontrolled Loading Loss (lb/1,000 gal)} = \frac{12.46 \cdot 0.2 \cdot 11.00\ \text{psia} \cdot 50\ \text{lb}}{\text{lbmole} \cdot 533.17\ \text{R}} = 2.57\ \text{lb/1,000 gal}$$

[8] Hourly Loading Rate obtained from information provided by TGTI Revised Design Parameters email from Ms. Denise Rogers (TGTI) to Mr. Brian Burdorf (Trinity Consultants) on February 25, 2018.
[9] Uncontrolled VOC Hourly Emissions (lb/hr) = Uncontrolled Loading Loss (lb/1,000 gal) x Hourly Loading Rate (bbl/hr) x 42 gal/bbl x TOC to VOC Factor x (1/1,000)

$$\text{Crude Oil Uncontrolled Loading Emissions (lb/hr)} = \frac{2.57\ \text{lb} \cdot 60{,}000\ \text{bbl} \cdot 42\ \text{gal} \cdot 1.00 \cdot 1}{1{,}000\ \text{gal} \cdot \text{hr} \cdot \text{bbl} \cdot 1{,}000} = 6{,}478\ \text{lb/hr}$$

Annual Loading Emissions

Liquid Loaded [1]	Saturation Factor [2]	Annual Average Temp [3] (°F)	Annual Average Temp [3] (°R)	Vapor MW (lb/lb mol)	Average True Vapor Pressure (TVP) [4] (psia)	Arrival Emission Factor [5] (lb/1,000 gal)	Generated Emission Factor [6] (lb/1,000 gal)	Uncontrolled Loading Loss [7] (lb/1,000 gal)	TOC to VOC Factor	Annual Loading Rate [8] (bbl/yr)	Uncontrolled VOC Annual Emissions [9] (tpy)
Crude Oil	0.2	73.50	533.17	50	11.00	--	--	2.57	1.00	192,000,000	10,364.91
Condensate	0.2	73.50	533.17	62	9.25	--	--	2.68	1.00	192,000,000	10,807.77

[1] For annual emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.
[2] Saturation factor for marine loading obtained from U.S. EPA 42, Section 5.2 (1/95), Table 5.2-1.
[3] Average of monthly average liquid surface temperature was used .
[4] Average true vapor pressure for Crude oil and Condensate obtained from information provided by Texas Gulf Terminals
[5] Arrival emission factor for crude/condensate loading obtained from U.S. EPA 42, Section 5.2 (1/95), Table 5.2-3.
[6] Generated emission factor is calculated using equation 3 from U.S. EPA 42, Section 5.2 (1/95).
[7] Uncontrolled Loading Loss (lb/1,000 gal) = 12.46 x Saturation Factor x Average TVP of Liquid Loaded (psia) x Vapor MW (lb/lbmol) / Average Temperature of Bulk Liquid Loaded (°R)

$$\text{Crude Oil Uncontrolled Loading Loss (lb/1,000 gal)} = \frac{12.46 \cdot 0.2 \cdot 11.00\ \text{psia} \cdot 50\ \text{lb}}{\text{lbmole} \cdot 533.17\ \text{R}} = 2.57\ \text{lb/1,000 gal}$$

[8] Annual Loading Rate obtained from information provided by TGTI Revised Design Parameters email from Ms. Denise Rogers (TGTI) to Mr. Brian Burdorf (Trinity Consultants) on February 25, 2018 and June 22, 2018.
[9] Uncontrolled VOC Loading Emissions (tpy) = Uncontrolled Loading Loss (lb/1,000 gal) x Annual Loading Rate (bbl/yr) x 42 gal/bbl x TOC to VOC Factor x (1/1,000) x (1 ton/2,000 lb)

$$\text{Crude Oil Uncontrolled Loading Emissions (tpy)} = \frac{2.57\ \text{lb} \cdot 192{,}000{,}000\ \text{bbl} \cdot 42\ \text{gal} \cdot 1.00 \cdot 1 \cdot 1\ \text{ton}}{1{,}000\ \text{gal} \cdot \text{yr} \cdot \text{bbl} \cdot 1{,}000 \cdot 2{,}000\ \text{lb}} = 10{,}365\ \text{tpy}$$

Hourly and Annual H_2S Emissions Estimates for Loading of Crude Oil and Condensate

Parameter	Value	Unit
H_2S MW	34.1	lb/lbmol
H_2S Max Vapor Fraction in Crude oil [1]	2.40E-05	
H_2S Max Vapor Fraction in Condensate [1]	2.40E-05	
Maximum Mass Ratio of H_2S in Crude Oil [2]	2.19E-05	lb H_2S/lb VOC
Maximum Mass Ratio of H_2S in Condensate [2]	1.76E-05	lb H_2S/lb VOC

[1] Maximum H_2S vapor fraction is assumed to be 24 ppmv for sweet crude.
[2] H_2S Mass Ratio in Crude Oil/Condensate (lb H_2S/lb VOC) = H_2S Vapor Fraction in Crude Oil/Condensate x H_2S MW (lb/lbmole)/Crude Oil/Condensate Vapor MW (lb/lbmole) x 14.7 psia/Vapor Pressure of Crude Oil/Condensate (psia)

$$\text{Max } H_2S \text{ Mass Ratio in Crude Oil (lb } H_2S\text{/lb VOC)} = \frac{2.40\text{E-05} \cdot 34.1\ \text{lb} \cdot \text{lbmole} \cdot 14.7\ \text{psia}}{\text{lbmole} \cdot 50\ \text{lb} \cdot 11\ \text{psia}} = 2.19\text{E-05 lb H2S/lb VOC}$$

Liquid Loaded [1]	Maximum TVP [2] (psia)	Uncontrolled VOC Hourly Emissions (lb/hr)	Uncontrolled VOC Annual Emissions (tpy)	H_2S Hourly Emissions [3] (lb/hr)	H_2S Annual Emissions [4] (tpy)
Crude Oil	11.00	6,478	10,365	0.14	0.23
Condensate	11.00	7,774	10,808	0.17	0.24

[1] For hourly and annual emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.
[2] Maximum true vapor pressure for Crude oil and Condensate obtained from information provided by Texas Gulf Terminals
[3] H_2S Hourly Emissions (lb/hr) = Max H_2S Mass Ratio in Crude/Condensate (lb H_2S/lb VOC) x Uncontrolled VOC Hourly Emissions (lb/hr)

$$H_2S \text{ Hourly Emissions from Crude Oil (lb/hr)} = \frac{2.19\text{E-05 lb H2S} \cdot 7{,}774\ \text{lb}}{\text{lb VOC} \cdot \text{hr}} = 0.14\ \text{lb/hr}$$

[4] H_2S Annual Emissions (tpy) = Max H_2S Mass Ratio in Crude/Condensate (lb H_2S/lb VOC) x Uncontrolled VOC Annual Emissions (tpy)

$$H_2S \text{ Annual Emissions from Crude Oil (tpy)} = \frac{2.19\text{E-05 lb H2S} \cdot 10{,}808\ \text{tpy}}{\text{lb VOC}} = 0.23\ \text{tpy}$$

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Marine Loading (DWP Emissions Source for PSD Applicability)
Hazardous Air Pollutants

Parameter	Value	Unit
Max. benzene vapor weight % in Crude Oil [1]	0.95%	
Max. benzene vapor weight % in Condensate [1]	0.43%	
Max toluene Vapor weight % in Crude Oil [1]	0.98%	
Max toluene Vapor weight % in Condensate [1]	0.37%	

[1] Benzene and toluene vapor weight fraction is based on Tanks 4.09D run.

Pollutant	Liquid Loaded [1]	Uncontrolled VOC Hourly Emissions (lb/hr)	Uncontrolled VOC Annual Emissions (tpy)	Maximum Emissions [2] (lb/hr)	Annual Emissions [3] (tpy)
Benzene	Crude Oil	6,478	10,365	61.54	98.47
	Condensate	7,774	10,808	33.43	46.47
Toluene	Crude Oil	6,478	10,365	63.49	101.58
	Condensate	7,774	10,808	28.76	39.99

[1] For hourly and annual emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.
[2] Benzene Hourly Emissions (lb/hr) = Max Benzene % in Crude/Condensate Vapors x Uncontrolled VOC Hourly Emissions (lb/hr)
[3] Emissions are based on the total VOC emissions for Loading of Crude Oil and Condensate calculated in the previous table.

$$\text{Benzene Hourly Emissions from Crude Oil (lb/hr)} = \frac{0.95\% \quad 6{,}478 \text{ lb}}{\text{hr}} = 61.54 \text{ lb/hr}$$

Toluene Hourly Emissions (lb/hr) = Max Toluene % in Crude/Condensate Vapors x Uncontrolled VOC Hourly Emissions (lb/hr)

$$\text{Toluene Hourly Emissions from Crude Oil (lb/hr)} = \frac{0.98\% \quad 6{,}478 \text{ lb}}{\text{hr}} = 63.49 \text{ lb/hr}$$

[3] Benzene Annual Emissions (tpy) = Max Benzene % in Crude/Condensate Vapors x Uncontrolled VOC Annual Emissions (tpy)

$$\text{Benzene Annual Emissions from Crude Oil (tpy)} = \frac{0.95\% \quad 10{,}365 \text{ tons}}{\text{yr}} = 98.47 \text{ tpy}$$

Toluene Annual Emissions (tpy) = Max Toluene % in Crude/Condensate Vapors x Uncontrolled VOC Annual Emissions (tpy)

$$\text{Toluene Annual Emissions from Crude Oil (tpy)} = \frac{0.98\% \quad 10{,}365 \text{ tons}}{\text{yr}} = 101.58 \text{ tpy}$$

Texas Gulf Terminals Inc.
Fugitives for the SPM System (DWP Emissions Source for PSD Applicability)
Emission Calculations

Maximum w/ Contingency (days p	365	days
	24	hr/day

Emission Calculations [1]

Component Type	Total Number of Components [1]	Oil & Gas Emission Factor Type (lb/hr)	Fugitive Emission Factor [2] (lb/hr/ component)	Total Organic Compound lbs/hr	Total Organic Compound lbs/day	Total Organic Compound tons/project
Valves	8	Light Liquid (Light Oil > 20° API)	5.50E-03	4.40E-02	1.06	0.19
Flanges	26	Light Liquid (Light Oil > 20° API)	2.43E-04	6.32E-03	0.15	2.77E-02
	Total TOC [4] - Heavy Oil Streams			**0.05**	**1.21**	**0.22**

Notes:

[1] Component counts are based on Engineering design information provided by Lloyd Engineering to Trinity Consultants on April 12, 2018.

[2] Emission Factors were obtained from *Table 4. Average Emission Factors - Petroleum Industry* (Oil & Gas Production Operations) of TCEQ's Addendum to RG-360A, Emission Factors for Equipment Leak Fugitives Components, January 2008.

[3] Fugitive emissions are conservatively estimated to be 100% VOC.

[4] Annual operating hours are conservatively assumed to be 8,760 hours per year.

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Tug Boat - Supply Boat Main Engines
Criteria Pollutants

Engine Rating [1], [4]	=	5,966	kW
		8,000	HP
Total Operating Time [2]		3,600	hrs/yr
Operating load [2]	=	90%	
Operating Time at 90% Operating	=	6	hrs/day
Load [2]		672	hrs/yr
Operating load [2]		40%	
Operating Time at 40% Operating		18	hrs/day
Load [2]		2,928	hrs/yr
Blended Time Weighted Operating Load [2]		49.33%	
Fuel Type [3]	=	Diesel	
Engine Speed [4]	=	1800	rpm

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions from 1 tug	Maximum Daily Emissions from 1 tug	Annual Emissions from 1 tug	Maximum Emissions from both tugs	Maximum Daily Emissions from both tugs	Annual Emissions from both tugs
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)	(lb/hr)	(lb/day)	(tons/yr)
PM	AP-42	[6]	7.00E-04	lb/HP-hr	5.04	66.30	4.97	10.08	132.60	9.94
PM_{10}	AP-42	[5]	4.01E-04	lb/HP-hr	2.89	37.99	2.85	5.78	75.98	5.70
$PM_{2.5}$	AP-42	[5]	3.89E-04	lb/HP-hr	2.80	36.86	2.76	5.60	73.73	5.53
NO_x	IMO Tier II	[4]	7.85E+00	g/kW-hr	92.89	1221.98	91.65	185.78	2443.95	183.29
SO_2	Fuel S Content	[3]	7.48E-04	lb/HP-hr	5.38	70.82	5.31	10.77	141.64	10.62
CO	AP-42	[6]	5.50E-03	lb/HP-hr	39.60	520.92	39.07	79.20	1041.85	78.14
VOC	AP-42	[6],[8]	6.42E-04	lb/HP-hr	4.62	60.76	4.56	9.24	121.53	9.11
Pb	EPA	[7]	2.03E-07	lb/HP-hr	1.46E-03	1.92E-02	1.44E-03	2.92E-03	3.85E-02	2.88E-03
H_2SO_4	Fuel S Content	[3]	2.34E-05	lb/HP-hr	1.68E-01	2.21E+00	1.66E-01	3.36E-01	4.42E+00	3.32E-01

[1] Representative Tug boat engine assumed to be used as the vessels that will be contracted are unknown at this time. Two main engines with combined capacity of 8000 hp as a worse care. Information provided by Texas Gulf Terminals (April 13 2018)

[2] Per information provided - 30-50% capacity during normal operations (not pulling crude carriers). 90% only during heavy load crude carriers. Information regarding operating hours and operating times at 40% and 90% loads is provided by Texas Gulf Terminals. Maximum hourly emissions are based on 90% load while daily and annual averages are based on the average load.

[3] Sulfur content of 0.1 % is used for all diesel combustion sources per IMO 2015 standards. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO2 and 2 percent of sulfur in the fuel is oxidized to H2SO4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

[4] Cummins QSK60 models meet IMO 2 standards per the information on their website. The RPM is estimated at 1800 based on the Cummins HP data of similar engines. Information seen on the website on 14 April 2018.

[5] PM_{10} and $PM_{2.5}$ emission factors based on AP-42 Chapter 3, Table 3.4-2, Particulate and Particle-sizing Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996). An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr. PM < 3um taken as $PM_{2.5}$. Total particulate emissions is the sum of filterable and condensable particulate emissions.

[6] Emission factors are based on AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996).

[7] Lead emission factor was obtained from EPA guidance document: Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2. Emission factor for distillate oil-fired gas turbines was used as a surrogate for distillate oil-fired engines due to lack of emission factors. An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr.

[8] Per footnote f of AP-42 Chapter 3, Table 3.4-1, non methane VOC emission factor has been taken as 91% of TOC emission factor.

Sample Calculations:

Weighted Average Operating Load = (0.9 x 672 hrs + 0.4 x 2928 hrs) / (672 hrs + 2928 hrs) = 49.33%
Max LB/HR Emissions (PM) from one tug = 0.0007 lb/HP-hr x 8000 HP x 90% = 5.04 lb/hr
Max Daily Emissions (PM) from one tug = 0.0007 lb/HP-hr x 8000 HP x 49.33% x 24 hrs/day= 66.29952 lb/day
Annual Emissions (PM) from one tug = 0.0007 lb/HP-hr x 8000 HP x 49.33% x 3600 hrs/yr x 24 hrs/day / (2000 lb/ton) = 4.972464 tpy
Annual Emissions (PM) from both tugs = 2 x 4.972464 tpy = 9.944928 tpy
Max LB/HR Emissions (NOx) from one tug = 7.8477 g/kW-hr x 5965.6972 KW / (453.59 g/lb) x 90% = 92.89 lb/hr

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Tug Boat - Supply Boat Main Engines
Hazardous Air Pollutants

Engine Rating [1], [7]	=	5,966	kW
		8,000	HP
Operating Time [2]	=	24	hrs/day
[2]		3,600	hrs/yr
Fuel Type [6]	=	Diesel	
Maximum Operating Load [2]		90%	
Blended Time Weighted Operating Load [2]	=	49.33%	

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions from 1 tug	Maximum Daily Emissions from 1 tug	Annual Emissions from 1 tug	Maximum Emissions from both tugs	Maximum Daily Emissions from both tugs	Annual Emissions from both tugs
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)	(lb/hr)	(lb/day)	(tons/yr)
Acetaldehyde	AP-42	[3],[5]	2.52E-05	lb/MMBtu	1.27E-03	1.67E-02	1.25E-03	2.54E-03	3.34E-02	2.51E-03
Acrolein	AP-42	[3],[5]	7.88E-06	lb/MMBtu	3.97E-04	5.22E-03	3.92E-04	7.94E-04	1.04E-02	7.84E-04
Benzene	AP-42	[3],[5]	7.76E-04	lb/MMBtu	3.91E-02	5.14E-01	3.86E-02	7.82E-02	1.03E+00	7.72E-02
Formaldehyde	AP-42	[3],[5]	7.89E-05	lb/MMBtu	3.98E-03	5.23E-02	3.92E-03	7.95E-03	1.05E-01	7.85E-03
Toluene	AP-42	[3],[5]	2.81E-04	lb/MMBtu	1.42E-02	1.86E-01	1.40E-02	2.83E-02	3.73E-01	2.79E-02
Xylenes	AP-42	[3],[5]	1.93E-04	lb/MMBtu	9.73E-03	1.28E-01	9.60E-03	1.95E-02	2.56E-01	1.92E-02
Total PAH	AP-42	[4],[5]	2.12E-04	lb/MMBtu	1.07E-02	1.41E-01	1.05E-02	2.14E-02	2.81E-01	2.11E-02
Naphthalene	AP-42	[4],[5]	1.30E-04	lb/MMBtu	6.55E-03	8.62E-02	6.46E-03	1.31E-02	1.72E-01	1.29E-02
Total VOC HAPs					**8.59E-02**	**1.13E+00**	**8.47E-02**	**1.72E-01**	**2.26E+00**	**1.69E-01**

[1] Representative Tug boat engine assumed to be used as the vessels that will be contracted are unknown at this time. Two main engines with combined capacity of 8000 hp as a worse care. Information provided by Texas Gulf Terminals (April 13 2018)

[2] Per information provided - 30-50% capacity during normal operations (not pulling crude carriers). 90% only during heavy load crude carriers. Information regarding operating hours and operating times at 40% and 90% loads is provided by Texas Gulf Terminals. Maximum hourly emissions are based on 90% load while daily and annual averages are

[3] Emission factors based on AP-42, Chapter 3, Table 3.4-3, Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[4] Emission factors based on AP-42, Chapter 3, Table 3.4-4, PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[5] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

[6] Diesel is proposed as fuel for tug boats.

[7] Based on Engine Specification obtained from Manufacturer's website for Cummins QSK 60 MCRS Engine. https://marine.cummins.com/MarineECM/MarineContent/SiteContent/en/Binary_Asset/attachments/Products/Commercial_Propulsion/QSK60_MCRS/QSK60_IMO_Tier_II_and_EPA_Tier_3_Certified_Ratings_SS.pdf

Sample Calculations:

Max LB/HR Emissions (Acetaldehyde) from one tug = 0.0000252 lb/MMBtu /1000000 x 7000 Btu/hp-hr x 8000 HP x 90% = 0.0013 lb/hr

Max Daily Emissions (Acetaldehyde) from one tug = 0.0013 lb/hr x 49.33% / 90% x 24 hrs/day= 0.0167 lb/day

Annual Emissions (Acetaldehyde) from one tug = 0.0013 lb/hr x 49.33% / 90% x 3600 hrs/yr = 0.0013 tpy

Annual Emissions (Acetaldehyde) from both tugs = 2 x 0.0013 tpy = 0.0025 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Tug Boat - Supply Boat Main Engines
Greenhouse Gases

Engine Rating [1]	=	5,966	kW
		8,000	HP
Operating Time [2]	=	24	hrs/day
[2]		3,600	hrs/yr
Total number of events [2]	=	1	events/yr
Fuel Type [7]	=	Diesel	
Blended Time Weighted Operating Load [2]	=	49.33%	

Pollutants	Global Warming Potential (100 yr.)
CO_2	1
CH_4	25
N_2O	298

Pollutant	Emission Factor Basis		Emission Factor		Average Emissions from 1 tug [5]	Average Daily Emissions from 1 tug [5]	Annual Emissions from 1 tug	Average Emissions from both tugs	Average Daily Emissions from both tugs	Annual Emissions from both tugs
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)	(lb/hr)	(lb/day)	(tons/yr)
CO_2	EPA	[3]	7.40E+01	kg/MMBtu	4,504	108,104	8,108	9,009	216,208	16,216
CH_4	EPA	[4]	3.00E-03	kg/MMBtu	1.83E-01	4.38E+00	3.29E-01	3.65E-01	8.77E+00	6.58E-01
N_2O	EPA	[4]	6.00E-04	kg/MMBtu	3.65E-02	8.77E-01	6.58E-02	7.31E-02	1.75E+00	1.32E-01
CO_2e	EPA	[6]	--	--	4,520	108,475	8,136	**9,040**	**216,950**	**16,271**

[1] Representative Tug boat engine assumed to be used as the vessels that will be contracted are unknown at this time. Two main engines with combined capacity of 8000 hp as a worse care. Information provided by Texas Gulf Terminals (April 13 2018)

[2] Per information provided - 30-50% capacity during normal operations (not pulling crude carriers). 90% only during heavy load crude carriers. Information regarding operating hours and operating times at 40% and 90% loads is provided by Texas Gulf Terminals. Maximum hourly emissions are based on 90% load while daily and annual averages are based on the average load.

[3] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[4] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[5] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

[6] CH_4, CO_2 and N_2O are included in the emissions of CO_2 equivalent (CO_2e), weighted according to their global warming potential (GWP). The GWP was obtained from table A-1 to Subpart A of Part 98. This is consistent with TCEQ 2015 guidance: https://www.tceq.texas.gov/assets/public/permitting/air/factsheets/factsheets-psdghg-6291.pdf
CH4 = 25, N2O = 298.

[7] Diesel is proposed as fuel for tug boats.

Sample Calculations:

Max LB/HR Emissions (CO2) from one tug = 73.96 kg/MMBtu x 2.20462 Lb/Kg /1000000 x 7000 Btu/hp-hr x 8000 HP x 49.33% = 4504.3257 lb/hr
Max Daily Emissions (CO2) from one tug = 4504.3257 lb/hr x 24 hrs/day= 108103.8173 lb/day
Annual Emissions (CO2) from one tug = 4504.3257 lb/hr x 3600 hrs/yr / 2000 lb/ton= 8107.7863 tpy
Annual Emissions (CO2) from both tugs = 2 x 8107.7863 tpy = 16215.5726 tpy
CO2e (tpy) = 16216 tpy CO2 x 1 + 0.7 tpy CH4 x 25 + 0.1 tpy N2O x 298 = 16271 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Representative Tug Boats Auxiliary Engines
Criteria Pollutants and Sulfuric Acid

Generator Power Rating [1]	=	75	kW
Engine Rating [1]		100	HP @ 1800 rpm
Operating Time [2]	=	24	hour/day
		3,600	hrs/year
Operating load [2]	=	60%	
Fuel Type [3]	=	Diesel	
Number of Engines [1]		4	

Pollutant	Emission Factor Basis		Emission Factor		Max Hourly Emissions from one engine	Max Daily Emissions from one engine	Annual Emissions from one engine	Max Hourly Emissions from 4 engines	Max Daily Emissions from 4 engines	Annual Emissions from 4 engines
			Value	Units	(lb/hr)	(lb/day)	(tpy)	(lb/hr)	(lb/day)	(tpy)
PM	40 CFR 89.112	[5]	4.93E-04	lb/hp-hr	0.03	0.71	0.05	0.12	2.84	0.21
PM_{10}	40 CFR 89.112, AP-42	[5],[4]	4.93E-04	lb/hp-hr	0.03	0.71	0.05	0.12	2.84	0.21
$PM_{2.5}$	40 CFR 89.112, AP-42	[5],[4]	4.93E-04	lb/hp-hr	0.03	0.71	0.05	0.12	2.84	0.21
NO_x	40 CFR 89.112	[5]	1.09E-02	lb/hp-hr	0.65	15.62	1.17	2.60	62.50	4.69
SO_2	Fuel S Content	[3]	7.48E-04	lb/hp-hr	4.49E-02	1.08E+00	8.08E-02	1.79E-01	4.31E+00	3.23E-01
H_2SO_4	Fuel S Content	[3]	2.34E-05	lb/hp-hr	1.40E-03	3.36E-02	2.52E-03	5.61E-03	1.35E-01	1.01E-02
CO	40 CFR 89.112	[5]	8.22E-03	lb/hp-hr	0.49	11.84	0.89	1.97	47.35	3.55
VOC	AP-42	[6],[7]	2.51E-03	lb/hp-hr	0.15	3.62	0.27	0.60	14.48	1.09
Pb	EPA	[8]	2.90E-05	lb/MMBtu	1.22E-05	2.92E-04	2.19E-05	4.87E-05	1.17E-03	8.77E-05

[1] Data provided by Texas Gulf Terminals on April 13 2018. There are two tug boats with two auxiliary engines each.

[2] Operating hours assumed to be the same as that of the tug boat's main engine. Operating load assumed to be 60%.

[3] Emissions have been calculated based on a maximum sulfur content of 1000 ppmw in diesel fuel assuming that 98 wt.% of sulfur in the fuel is oxidized to SO_2 and 2 wt.% of sulfur in the fuel is oxidized to H_2SO_4 based on AP-42 Appendix A, table 3.4.1 footnote e and Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003. Heating value is obtained from Chevron Diesel Fuels Technical Review Table 4.3.

[4] Based on footnote b of AP-42 Chapter 3, Table 3.3-1, all PM is assumed to be < 1 µm. Therefore, it is assumed $PM_{2.5} = PM_{10} = PM$.

[5] From 40 CFR 89.112(a) Table 1. Emission Standards. 75 kW Tier 2 engine. Assumed that these engines are Tier II.

[6] Emission factors are based on AP-42, Chapter 3, Table 3.3-1, Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines (October 1996). Emission factors for diesel fuel are used.

[7] All TOC is assumed to be VOC. TOC emission factor has been calculated as the sum of exhaust and crankcase emission factors.

[8] Lead emission factor (2.9×10^{-5} lb/MMBtu) is obtained from EPA guidance document: Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2. Emission factor for distillate oil-fired gas turbines is used as a surrogate for distillate oil-fired engines due to lack of specific emission factors for distillate oil-fired engines.

Sample Calculations:

Max LB/HR Emissions (PM) from one engine = 0.0005 lb/hp-hr x 100 HP x 60% = 0.0296 lb/hr
Max Daily Emissions (PM) from one engine = 0.0296 lb/hr x 24 hrs/day= 0.7102 lb/day
Annual Emissions (PM) from one engine = 0.0296 lb/hr x 3600 hrs/yr / 2000 lb/ton= 0.7102 tpy
Annual Emissions (PM) from all engines = 4 x 0.05 tpy = 0.21 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Representative Tug Boats Auxiliary Engines
Hazardous Air Pollutants

Generator Power Rating [1]	=	75	kW
Engine Rating [1]		100	HP @ 1800 rpm
Operating Time [2]	=	24	hours/day
		3,600	hrs/year
Operating load [2]	=	60%	
Fuel Type [3]	=	Diesel	
Number of Engines [1]		4	

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions from one engine	Max Daily Emissions from one engine	Annual Emissions from one engine	Hourly Emissions from 4 engines	Max Daily Emissions from 4 engines	Annual Emissions from 4 engines
			Value	Units	(lb/hr)	(lb/day)	(tpy)	(lb/hr)	(lb/day)	(tpy)
Acetaldehyde	AP-42	[4],[5]	7.67E-04	lb/MMBtu	3.22E-04	7.73E-03	5.80E-04	1.29E-03	3.09E-02	2.32E-03
Acrolein	AP-42	[4],[5]	9.25E-05	lb/MMBtu	3.89E-05	9.32E-04	6.99E-05	1.55E-04	3.73E-03	2.80E-04
Benzene	AP-42	[4],[5]	9.33E-04	lb/MMBtu	3.92E-04	9.40E-03	7.05E-04	1.57E-03	3.76E-02	2.82E-03
Formaldehyde	AP-42	[4],[5]	1.18E-03	lb/MMBtu	4.96E-04	1.19E-02	8.92E-04	1.98E-03	4.76E-02	3.57E-03
Toluene	AP-42	[4],[5]	4.09E-04	lb/MMBtu	1.72E-04	4.12E-03	3.09E-04	6.87E-04	1.65E-02	1.24E-03
Xylenes	AP-42	[4],[5]	2.85E-04	lb/MMBtu	1.20E-04	2.87E-03	2.15E-04	4.79E-04	1.15E-02	8.62E-04
1,3-Butadiene	AP-42	[4],[5]	3.91E-05	lb/MMBtu	1.64E-05	3.94E-04	2.96E-05	6.57E-05	1.58E-03	1.18E-04
Total PAH	AP-42	[4],[5]	1.68E-04	lb/MMBtu	7.06E-05	1.69E-03	1.27E-04	2.82E-04	6.77E-03	5.08E-04
Naphthalene	AP-42	[4],[5]	8.48E-05	lb/MMBtu	3.56E-05	8.55E-04	6.41E-05	1.42E-04	3.42E-03	2.56E-04
Total VOC HAPs					**1.66E-03**	**3.99E-02**	**2.99E-03**	**6.65E-03**	**1.60E-01**	**1.20E-02**

[1] Data provided by Texas Gulf Terminals on April 13 2018. There are two tug boats with two auxiliary engines each.

[2] Operating hours assumed to be the same as that of the tug boat's main engine. Operating load assumed to be 60%.

[3] Calculations based on the use of Diesel for all diesel combustion sources.

[4] Emission factors based on AP-42, Chapter 3, Table 3.3-2 Speciated Organic Compound Emission Factors for Uncontrolled Diesel Engines (October 1996).

[5] An average Brake Specific Fuel Consumption (BFSC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Sample Calculations:

Max LB/HR Emissions (Acetaldehyde) from one engine = 0.000767 lb/MMBtu /1000000 x 7000 Btu/hp-hr x HP x 60% = 0.0003 lb/hr
Max Daily Emissions (Acetaldehyde) from one engine = 0.0003 lb/hr x 24 hrs/day= 0.0077 lb/day
Annual Emissions (Acetaldehyde) from one engine = 0.0003 lb/hr x 3600 hrs/yr / 2000 lb/ton = 0.0006 tpy
Annual Emissions (Acetaldehyde) from 4 engines = 4 x 0.0006 tpy = 0.0023 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Representative Tug Boats Auxiliary Engines
Greenhouse Gases

Generator Power Rating [1]	=	75	kW
Engine Rating [1]		100	HP @ 1800 rpm
Operating Time [2]	=	24	hour/day
		3,600	hrs/year
Operating load [2]	=	60%	
Fuel Type [3]	=	Diesel	
Number of Engines [1]		4	

Chemicals	Global Warming Potential (100 yr.)
CO_2	1
CH_4	25
N_2O	298

Pollutant	Emission Factor Basis		Emission Factor Value	Emission Factor Units	Maximum Hourly Emissions from All Engines [7] (lb/hr)	Maximum Daily Emissions from All Engines (lb/day)	Annual Emissions from All Engines tpy
CO_2	40 CFR 98 Subpart C	[4]	73.96	kg/MMBtu	274	6,574	493
CH_4	40 CFR 98 Subpart C	[5]	3.00E-03	kg/MMBtu	1.11E-02	0.27	2.00E-02
N_2O	40 CFR 98 Subpart C	[5]	6.00E-04	kg/MMBtu	2.22E-03	0.05	4.00E-03
CO_2e	40 CFR 98 Subpart C	[6]	--	--	275	6,597	495

[1] Data provided by Texas Gulf Terminals on April 13 2018. There are two tug boats with two auxiliary engines each.

[2] Operating hours assumed to be the same as that of the tug boat's main engine. Operating load assumed to be 60%.

[3] Calculations based on the use of Diesel for all diesel combustion sources.

[4] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[5] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[6] CH_4, CO_2 and N_2O are included in the emissions of CO_2 equivalent (CO_2e), weighted according to their global warming potential (GWP). The GWP was obtained from table A-1 to Subpart A of Part 98. This is consistent with TCEQ 2015 guidance: https://www.tceq.texas.gov/assets/public/permitting/air/factsheets/factsheets-psdghg-6291.pdf

[7] An average Brake Specific Fuel Consumption (BFSC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Sample Calculations:

Max LB/HR Emissions (CO2) from engines = 4 x 73.96 kg/MMBtu x 2.20462 Lb/Kg /1000000 x 7000 Btu/hp-hr x HP x 60% = 273.9302 lb/hr
Max Daily Emissions (CO2) from engines = 273.9302 lb/hr x 24 hrs/day= 6574.325 lb/day
Annual Emissions (CO2) from engines = 273.9302 lb/hr x 3600 hrs/yr / 2000 lb/ton= 493.1 tpy
CO2e (tpy) = 493 tpy CO2 x 1 + 0.02 tpy CH4 x 25 + 0.004 tpy N2O x 298 = 495 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Pilot Boats Engine
Criteria Pollutants

Engine Rating [1], [4]	=	559	kW
		750	HP
Operating Time [2]	=	12	hrs/day
[2]		1,728	hrs/yr
Fuel Type [3]	=	Diesel	
Engine Speed [4]	=	1800	rpm
Operating Load [2]	=	100%	
Number of Pilot Boats [2]		1	

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions from pilot boat [2]	Maximum Daily Emissions from pilot boat	Annual Emissions from pilot boat
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
PM	AP-42	[6]	7.00E-04	lb/HP-hr	1.05	12.60	0.91
PM_{10}	AP-42	[5]	4.01E-04	lb/HP-hr	0.60	7.22	0.52
$PM_{2.5}$	AP-42	[5]	3.89E-04	lb/HP-hr	0.58	7.01	0.50
NO_x	IMO Tier III	[4]	2.01E+00	g/kW-hr	4.96	59.48	4.28
SO_2	Fuel S Content	[3]	7.48E-04	lb/HP-hr	1.12	13.46	0.97
CO	AP-42	[6]	5.50E-03	lb/HP-hr	8.25	99.00	7.13
VOC	AP-42	[6],[8]	6.42E-04	lb/HP-hr	0.96	11.55	0.83
Pb	EPA	[7]	2.03E-07	lb/HP-hr	3.05E-04	3.65E-03	2.63E-04
H_2SO_4	Fuel S Content	[3]	2.34E-05	lb/HP-hr	3.50E-02	4.20E-01	3.03E-02

[1] Representative Pilot boat engine assumed. Information provided by Texas Gulf Terminals (April 13 2018). Each boat has twin engines.

[2] Assumed to operate for 12 hours a day and half the time tug boats operate. Operating hours of tug-boats provided by Texas Gulf Terminals.

[3] Sulfur content of 0.1% is used per IMO standards for 2015. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO2 and 2 percent of sulfur in the fuel is oxidized to H2SO4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

[4] The engines comply with IMO III standards per the information received from Texas Gulf Terminals. The RPM is assumed at 1800.

[5] PM_{10} and $PM_{2.5}$ emission factors based on AP-42 Chapter 3, Table 3.4-2, Particulate and Particle-sizing Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996). An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr. PM < 3um taken as $PM_{2.5}$. Total particulate emissions is the sum of filterable and condensable particulate emissions.

[6] Emission factors are based on AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996).

[7] Lead emission factor was obtained from EPA guidance document: Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2. Emission factor for distillate oil-fired gas turbines was used as a surrogate for distillate oil-fired engines due to lack of emission factors. An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr.

[8] Per footnote f of AP-42 Chapter 3, Table 3.4-1, non methane VOC emission factor has been taken as 91% of TOC emission factor.

Sample Calculations:

Max LB/HR Emissions (PM) from one engine = 0.0007 lb/HP-hr x 750 HP x 100% = 1.05 lb/hr
Max Daily Emissions (PM) from one engine = 1.05 lb/hr x 12 hrs/day= 12.6 lb/day
Annual Emissions (PM) from one engine = 1.05 lb/hr x 1728 hrs/yr / 2000 lb/ton= 0.9072 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Pilot Boats Engine
Hazardous Air Pollutants

Engine Rating [1], [7]	=	559	kW
		750	HP
Operating Time [2]	=	12	hrs/day
[2]		1,728	hrs/yr
Fuel Type [6]	=	Diesel	
Operating load [2]	=	100%	

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions from pilot boat	Maximum Daily Emissions from pilot boat	Annual Emissions from pilot boat
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
Acetaldehyde	AP-42	[3],[5]	2.52E-05	lb/MMBtu	2.65E-04	3.18E-03	2.29E-04
Acrolein	AP-42	[3],[5]	7.88E-06	lb/MMBtu	8.27E-05	9.93E-04	7.15E-05
Benzene	AP-42	[3],[5]	7.76E-04	lb/MMBtu	8.15E-03	9.78E-02	7.04E-03
Formaldehyde	AP-42	[3],[5]	7.89E-05	lb/MMBtu	8.28E-04	9.94E-03	7.16E-04
Toluene	AP-42	[3],[5]	2.81E-04	lb/MMBtu	2.95E-03	3.54E-02	2.55E-03
Xylenes	AP-42	[3],[5]	1.93E-04	lb/MMBtu	2.03E-03	2.43E-02	1.75E-03
Total PAH	AP-42	[4],[5]	2.12E-04	lb/MMBtu	2.23E-03	2.67E-02	1.92E-03
Naphthalene	AP-42	[4],[5]	1.30E-04	lb/MMBtu	1.37E-03	1.64E-02	1.18E-03
Total VOC HAPs					**1.79E-02**	**2.15E-01**	**1.55E-02**

[1] Representative Pilot boat engine assumed. Information provided by Texas Gulf Terminals (April 13 2018). Each boat has twin engines.

[2] Assumed to operate for 12 hours a day and half the time tug boats operate. Operating hours of tug-boats provided by Texas Gulf Terminals.

[3] Emission factors based on AP-42, Chapter 3, Table 3.4-3, Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[4] Emission factors based on AP-42, Chapter 3, Table 3.4-4, PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[5] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

[6] Diesel is proposed as fuel for pilot boats.

[7] Based on Engine Specification obtained from Manufacturer's website for Cummins QSK 60 MCRS Engine.
https://marine.cummins.com/MarineECM/MarineContent/SiteContent/en/Binary_Asset/attachments/Products/Commercial_Propulsion/QSK60_MCRS/QSK60_IMO_Tier_II_and_EPA_Tier_3_Certified_Ratings_SS.pdf

Sample Calculations:

Max LB/HR Emissions (Benzene) from twin engines = 2 x 0.000776 lb/MMBtu /1000000 x 7000 Btu/hp-hr x 750 HP x 100% = 0.0081 lb/hr
Max Daily Emissions (Benzene) from twin engines = 0.0081 lb/hr x 12 hrs/day= 0.0978 lb/day
Annual Emissions (Benzene) from twin engines = 0.0081 lb/hr x 1728 hrs/yr / 2000 lb/ton = 0.007 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Pilot Boats Engine
Greenhouse Gases

Engine Rating [1]		559	KW
		750	HP
Operating Time [2]	=	12	hrs/day
		1728	hrs/year
Operating load [2]	=	100%	
Fuel Type [3]	=	Diesel	

Chemicals	Global Warming Potential (100 yr.)
CO_2	1
CH_4	25
N_2O	298

Pollutant	Emission Factor Basis		Emission Factor Value	Emission Factor Units	Maximum Hourly Emissions [7] (lb/hr)	Maximum Daily Emissions (lb/day)	Annual Emissions tpy
CO_2	40 CFR 98 Subpart C	[4]	73.96	kg/MMBtu	1,712	20,545	1,479
CH_4	40 CFR 98 Subpart C	[5]	3.00E-03	kg/MMBtu	0.07	0.83	0.06
N_2O	40 CFR 98 Subpart C	[5]	6.00E-04	kg/MMBtu	0.01	0.17	0.01
CO_2e	40 CFR 98 Subpart C	[6]	--	--	1,718	20,615	1,484

[1] Representative Pilot boat engine assumed. Information provided by Texas Gulf Terminals (April 13 2018). Each boat has twin engines.

[2] This is based on the worst-case assumption, this engine will operate maximum 12.0 hrs/day, 100 hrs per year. Operating Load is assumed to be 100%.

[3] Diesel is proposed as fuel for pilot boats.

[4] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[5] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[6] CH_4, CO_2 and N_2O are included in the emissions of CO_2 equivalent (CO_2e), weighted according to their global warming potential (GWP). The GWP was obtained from table A-1 to Subpart A of Part 98. This is consistent with TCEQ 2015 guidance: https://www.tceq.texas.gov/assets/public/permitting/air/factsheets/factsheets-psdghg-6291.pdf
CH4 = 25, N2O = 298.

[7] An average Brake Specific Fuel Consumption (BFSC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Sample Calculations:

Max LB/HR Emissions (CO2) = 2 x 73.96 kg/MMBtu x 2.20462 Lb/Kg /1000000 x 7000 Btu/hp-hr x 750 HP x 100% = 1712.0638 lb/hr
Max Daily Emissions (CO2) from engines = 1712.0638 lb/hr x 24 hrs/day= 20544.7656 lb/day
Annual Emissions (CO2) from engines = 1712.0638 lb/hr x 1728 hrs/yr / 2000 lb/ton= 1479 tpy
CO2e (tpy) = 1479 tpy CO2 x 1 + 0.06 tpy CH4 x 25 + 0.012 tpy N2O x 298 = 1484 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Representative Helicopter
Criteria Pollutants, HAPs and GHG

Operating Time [1]	=	2	hour/day
		104	hrs/year
LTO [1] [2]		52	per year

Pollutant	Emission Factor Basis		Emission Factor Value	Emission Factor Units	Max Hourly Emissions (lb/hr)	Max Daily Emissions (lb/day)	Annual Emissions (tpy)
PM	Table 6-12 Year 2011 Gulfwide Emission Inventory Study (BOEM 2014-666) Twin Engine medium lift	[3]	6.00E-02	lb/LTO	0.03	0.06	1.56E-03
PM_{10}		[3]	6.00E-02	lb/LTO	0.03	0.06	1.56E-03
$PM_{2.5}$		[3]	6.00E-02	lb/LTO	0.03	0.06	1.56E-03
NO_x		[3]	1.95E+00	lb/LTO	0.98	1.95	5.07E-02
SO_2		[3]	2.90E-01	lb/LTO	0.15	0.29	7.54E-03
CO		[3]	5.33E+00	lb/LTO	2.67	5.33	1.39E-01
VOC		[3]	4.01E+00	lb/LTO	2.01	4.01	1.04E-01
CO_2		[3]	4.15E+02	lb/LTO	207.26	414.51	1.08E+01
CH_4		[3]	3.00E-02	lb/LTO	0.02	0.03	7.80E-04
N_2O		[3]	3.00E-02	lb/LTO	0.02	0.03	7.80E-04
Total GHG - CO_2e [4]					***212.10***	***424.20***	***11.03***
Acetaldehyde	Documentation for Aircraft Component of the National Emissions Inventory: Inventory Methodology USEPA, Emissions, Monitoring and Analysis	[2]	1.40E-04	tons/LTO	0.14	0.28	7.28E-03
Acetylene		[2]	1.29E-04	tons/LTO	0.13	0.26	6.71E-03
Ethylene		[2]	5.07E-04	tons/LTO	0.51	1.01	2.64E-02
Formaldehyde		[2]	4.03E-04	tons/LTO	0.40	0.81	2.10E-02
Propylene		[2]	1.49E-04	tons/LTO	0.15	0.30	7.72E-03
Total VOC HAPs					***1.33E+00***	***2.66E+00***	***6.90E-02***

[1] Calculations based on 1 trip/week and assumed to operate two hours during a trip.

[2] LTO = landing and take off cycle
Reference: "Documentation for Aircraft Component of the National Emissions Inventory: Inventory Methodology USEPA, Emissions, Monitoring and Analysis Division, Contract No.: EP-D-07-097, April 23, 2010.
Only top five HAP emission factors used. All other HAPs emission factors a factor of 10 or more lower.

[3] Helicopter emission factors from Table 6-12 Year 2011 Gulfwide Emission Inventory Study (BOEM 2014-666) Twin Engine medium lift. Used default trip times in BOEM report. No HAPs emission factors reported.

[4] CH_4, CO_2 and N_2O are included in the emissions of CO_2 equivalent (CO_2e), weighted according to their global warming potential (GWP). The GWP was obtained from table A-1 to Subpart A of Part 98. This is consistent with TCEQ 2015 guidance:
https://www.tceq.texas.gov/assets/public/permitting/air/factsheets/factsheets-psdghg-6291.pdf
CH4 = 25, N2O = 298.

Sample Calculations:

Max Daily Emissions (PM) = 0.06 lb/LTO x 1 LTO/day= 0.06 lb/day
Max LB/HR Emissions (PM) = 0.06 (lb/day) / 2 Hr/day = 0.03 lb/hr
Annual Emissions (PM) = 0.06 lb/LTO x 52 LTO/yr / 2000 lb/ton= 0.0016 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Carrier Main Engine in Safety Zone
Criteria Pollutants

Engine Rating [1], [4]	=	29,340	kW
		39,345	HP
Number of VLCCs [2]		8	per month
Loading time when in Safety Zone [2]		2	days
Operating Time [2]	=	24	hrs/day
		4,608	hrs/yr
Operating load [2]	=	25%	
Fuel Type [3]	=	Diesel	

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions	Maximum Daily Emissions	Annual Emissions
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
PM	BOEM 2014-666	[4]	7.40E-01	g/kW-hr	11.97	287.20	27.57
PM_{10}	BOEM 2014-666	[4]	7.40E-01	g/kW-hr	11.97	287.20	27.57
$PM_{2.5}$	BOEM 2014-666	[4]	6.80E-01	g/kW-hr	11.00	263.91	25.34
NO_x	BOEM 2014-666	[4]	1.95E+01	g/kW-hr	315.98	7583.55	728.02
SO_2	Fuel S Content	[3]	7.48E-04	lb/HP-hr	7.35E+00	1.77E+02	1.69E+01
CO	BOEM 2014-666	[4]	1.77E+00	g/kW-hr	28.62	686.94	65.95
VOC	AP-42 Chapter 3	[5]	6.42E-04	lb/HP-hr	6.31	151.45	14.54
Pb	EPA	[6]	2.03E-07	lb/HP-hr	2.00E-03	4.79E-02	4.60E-03
H_2SO_4	Fuel S Content	[3]	2.34E-05	lb/HP-hr	2.30E-01	5.51E+00	5.29E-01

[1] Representative engine specifications used from Apolytares Q88 vessel. Information received from Texas Gulf Terminals. Other vessels are expected to be smaller in capacity compared to the one represented here.

[2] Carrier assumed to operate at 25% capacity in the safety zone as it is tugged by tug boats. Worse case estimate of 8 VLCCs a month are assumed for emissions estimation. It takes two days for the VLCCs to load.

[3] Sulfur content of 1000 ppm has been used per IMO standards for 2015. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO2 and 2 percent of sulfur in the fuel is oxidized to H2SO4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

[4] Crude Carrier emission factors from Table 6-1 Year 2011 Gulfwide Emission Inventory Study (BOEM 2014-666) for Commercial Marine Vessels for Diesel. No HAPs emission factors reported.

[5] Emission factors are based on AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996).

[6] Lead emission factor was obtained from EPA guidance document: Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2. Emission factor for distillate oil-fired gas

Sample Calculations:

Max LB/HR Emissions (PM) = 0.74 g/kW-hr x 29340 KW / 453.59 g/lb x 25% = 11.9665 lb/hr
Max Daily Emissions (PM) = 11.9665 lb/hr x 24 hrs/day= 287.1968 lb/day
Annual Emissions (PM) = 11.9665 lb/hr x 4608 hrs/yr / 2000 lb/ton= 27.5709 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Carrier Main Engine in Safety Zone
Hazardous Air Pollutants

Engine Rating [1]	=	29,340	kW
		39,345	HP
Operating Time [2]	=	24	hrs/day
		4,608	hrs/yr
Fuel Type [6]	=	Diesel	
Engine Speed [1]	=	1,000	rpm
Operating load [2]	=	25%	

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions	Maximum Daily Emissions	Annual Emissions
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
Acetaldehyde	AP-42	[3],[5]	2.52E-05	lb/MMBtu	1.74E-03	4.16E-02	4.00E-03
Acrolein	AP-42	[3],[5]	7.88E-06	lb/MMBtu	5.43E-04	1.30E-02	1.25E-03
Benzene	AP-42	[3],[5]	7.76E-04	lb/MMBtu	5.34E-02	1.28E+00	1.23E-01
Formaldehyde	AP-42	[3],[5]	7.89E-05	lb/MMBtu	5.43E-03	1.30E-01	1.25E-02
Toluene	AP-42	[3],[5]	2.81E-04	lb/MMBtu	1.93E-02	4.64E-01	4.46E-02
Xylenes	AP-42	[3],[5]	1.93E-04	lb/MMBtu	1.33E-02	3.19E-01	3.06E-02
Total PAH	AP-42	[4],[5]	2.12E-04	lb/MMBtu	1.46E-02	3.50E-01	3.36E-02
Naphthalene	AP-42	[4],[5]	1.30E-04	lb/MMBtu	8.95E-03	2.15E-01	2.06E-02
Total VOC HAPs					**1.17E-01**	**2.82E+00**	**2.70E-01**

[1] Representative engine specifications used from Apolytares Q88 vessel. Information received from Texas Gulf Terminals. Other vessels are expected to be smaller in capacity compared to the one represented here.

[2] Carrier assumed to operate at 25% capacity in the safety zone as it is tugged by tug boats. Worse case estimate of 8 VLCCs a month are assumed for emissions estimation. It takes two days for the VLCCs to load.

[3] Emission factors based on AP-42, Chapter 3, Table 3.4-3, Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[4] Emission factors based on AP-42, Chapter 3, Table 3.4-4, PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[5] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

[6] Sulfur content of 1000 ppm has been used per IMO standards for 2015. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO2 and 2 percent of sulfur in the fuel is oxidized to H2SO4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

Sample Calculations:

Max LB/HR Emissions (Acetaldehyde) = 0.00003 lb/MMBtu x 7000 Btu/Hp-hr / 1000000 x 39344.94 HP x 25% = 0.0017 lb/hr
Max Daily Emissions (Acetaldehyde) = 0.0017 lb/hr x 24 hrs/day= 0.0416 lb/day
Annual Emissions (Acetaldehyde) = 0.0017 lb/hr x 4608 hrs/yr / 2000 lb/ton= 0.004 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Carrier Main Engine in Safety Zone
Greenhouse Gases

Engine Rating [1]	=	29,340	kW
		39,345	HP
Operating Time [2]	=	24	hrs/day
		4,608	hrs/yr
Fuel Type [7]	=	Diesel	
Engine Speed [1]	=	1,000	rpm
Operating load [2]	=	25%	

Pollutant	Emission Factor Basis		Emission Factor		Average Emissions [5]	Average Daily Emissions	Annual Emissions
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
CO_2	40 CFR 98 Subpart C	[3]	7.40E+01	kg/MMBtu	11,227	269,444	25,867
CH_4	40 CFR 98 Subpart C	[4]	3.00E-03	kg/MMBtu	0.46	10.93	1.05
N_2O	40 CFR 98 Subpart C	[4]	6.00E-04	kg/MMBtu	0.09	2.19	0.21
CO_2e	40 CFR 98 Subpart C	[6]	--	--	**11,265**	**270,369**	**25,955**

[1] Representative engine specifications used from Apolytares Q88 vessel. Information received from Texas Gulf Terminals. Other vessels are expected to be smaller in capacity compared to the one represented here.

[2] Carrier assumed to operate at 25% capacity in the safety zone as it is tugged by tug boats. Worse case estimate of 8 VLCCs a month are assumed for emissions estimation. It takes two days for the VLCCs to load.

[3] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[4] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[5] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

[6] CH_4, CO_2 and N_2O are included in the emissions of CO_2 equivalent (CO_2e), weighted according to their global warming potential (GWP). The GWP was obtained from table A-1 to Subpart A of Part 98. This is consistent with TCEQ 2015 guidance: https://www.tceq.texas.gov/assets/public/permitting/air/factsheets/factsheets-psdghg-6291.pdf
CH4 = 25, N2O = 298.

[7] Sulfur content of 1000 ppm has been used per IMO standards for 2015. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO2 and 2 percent of sulfur in the fuel is oxidized to H2SO4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

Sample Calculations:

Max LB/HR Emissions (CO2) = 73.96 kg/MMBtu x 2.20462 Lb/Kg /1000000 x 7000 Btu/hp-hr x 39344.94 HP x 25% = 11227 lb/hr
Max Daily Emissions (CO2) = 11227 lb/hr x 24 hrs/day= 269444.1899 lb/day
Annual Emissions (CO2) = 11227 lb/hr x 4608 hrs/yr / 2000 lb/ton= 25867 tpy
CO2e (tpy) = 25867 tpy CO2 x 1 + 1.05 tpy CH4 x 25 + 0.21 tpy N2O x 298 = 25955 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Crude Carrier Auxiliary Engines
Criteria Pollutants

Engine Rating [1], [4]	=	1,200	kW
		1,609	HP
Total Operating Time [2]		4,608	hrs/yr
Operating Load [2]		60%	
Fuel Type [3]	=	Diesel	
Engine Speed [4]	=	1800	rpm
Number of Aux Engines [1] [4]	=	3	

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions from 1 Engine	Maximum Daily Emissions from 1 Engine	Annual Emissions from 1 Engine	Maximum Emissions from all engines	Maximum Daily Emissions from all engines	Annual Emissions from all engines
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)	(lb/hr)	(lb/day)	(tons/yr)
PM	AP-42	[6]	7.00E-04	lb/HP-hr	0.68	16.22	1.56	2.03	48.66	4.67
PM_{10}	AP-42	[5]	4.01E-04	lb/HP-hr	0.39	9.29	0.89	1.16	27.88	2.68
$PM_{2.5}$	AP-42	[5]	3.89E-04	lb/HP-hr	0.38	9.02	0.87	1.13	27.06	2.60
NO_x	IMO Tier I	[4]	1.00E+01	g/kW-hr	15.95	382.86	36.75	47.86	1148.58	110.26
SO_2	Fuel S Content	[3]	7.48E-04	lb/HP-hr	0.72	17.33	1.66	2.17	51.98	4.99
CO	AP-42	[6]	5.50E-03	lb/HP-hr	5.31	127.45	12.24	15.93	382.35	36.71
VOC	AP-42	[6],[8]	6.42E-04	lb/HP-hr	0.62	14.87	1.43	1.86	44.60	4.28
Pb	EPA	[7]	2.03E-07	lb/HP-hr	1.96E-04	4.70E-03	4.52E-04	5.88E-04	1.41E-02	1.35E-03
H_2SO_4	Fuel S Content	[3]	2.34E-05	lb/HP-hr	2.26E-02	5.41E-01	5.20E-02	6.77E-02	1.62E+00	1.56E-01

[1] Representative engine specifications used from Apolytares Q88 vessel. Information received from Texas Gulf Terminals. Other vessels are expected to be smaller in capacity compared to the one represented here.

[2] Operating hours are assumed to be the same as that of the Carrier's main engine. Operating load of 60% is assumed.

[3] Sulfur content of 0.1% is used per IMO standards for 2015. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO2 and 2 percent of sulfur in the fuel is oxidized to H2SO4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

[4] The RPM is estimated at 1800 based on the Cummins HP data of similar engines as this is the best available data available currently. Information seen on the website on 14 April 2018. For conservative estimates IMO Tier 1 standard is assumed.

[5] PM_{10} and $PM_{2.5}$ emission factors based on AP-42 Chapter 3, Table 3.4-2, Particulate and Particle-sizing Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996). An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr. PM < 3um taken as $PM_{2.5}$. Total particulate emissions is the sum of filterable and condensable particulate emissions.

[6] Emission factors are based on AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996).

[7] Lead emission factor was obtained from EPA guidance document: Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2. Emission factor for distillate oil-fired gas turbines was used as a surrogate for distillate oil-fired engines due to lack of emission factors. An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr.

[8] Per footnote f of AP-42 Chapter 3, Table 3.4-1, non methane VOC emission factor has been taken as 91% of TOC emission factor.

Sample Calculations:

Max LB/HR Emissions (PM) from one engine = 0.0007 lb/HP-hr x 1609.2 HP x 60% = 0.6759 lb/hr
Max Daily Emissions (PM) from one engine = 0.6759 lb/hr x 24 hrs/day= 16.2207 lb/day
Annual Emissions (PM) from one engine = 0.6759 lb/hr x 4608 hrs/yr / 2000 lb/ton= 1.5572 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Crude Carrier Auxiliary Engines
Hazardous Air Pollutants

Engine Rating [1], [7]	=	1,200	kW
		1,609	HP
Operating Time [2]	=	24	hrs/day
[2]		4,608	hrs/yr
Fuel Type [6]	=	Diesel	
Operating Load [2]	=	60.00%	

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions from 1 engine	Maximum Daily Emissions from 1 engine	Annual Emissions from 1 engine	Maximum Emissions from all engines	Maximum Daily Emissions from all engines	Annual Emissions from all engines
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)	(lb/hr)	(lb/day)	(tons/yr)
Acetaldehyde	AP-42	[3],[5]	2.52E-05	lb/MMBtu	1.70E-04	4.09E-03	3.92E-04	3.41E-04	8.18E-03	7.85E-04
Acrolein	AP-42	[3],[5]	7.88E-06	lb/MMBtu	5.33E-05	1.28E-03	1.23E-04	1.07E-04	2.56E-03	2.45E-04
Benzene	AP-42	[3],[5]	7.76E-04	lb/MMBtu	5.24E-03	1.26E-01	1.21E-02	1.05E-02	2.52E-01	2.42E-02
Formaldehyde	AP-42	[3],[5]	7.89E-05	lb/MMBtu	5.33E-04	1.28E-02	1.23E-03	1.07E-03	2.56E-02	2.46E-03
Toluene	AP-42	[3],[5]	2.81E-04	lb/MMBtu	1.90E-03	4.56E-02	4.38E-03	3.80E-03	9.12E-02	8.75E-03
Xylenes	AP-42	[3],[5]	1.93E-04	lb/MMBtu	1.30E-03	3.13E-02	3.01E-03	2.61E-03	6.26E-02	6.01E-03
Total PAH	AP-42	[4],[5]	2.12E-04	lb/MMBtu	1.43E-03	3.44E-02	3.30E-03	2.87E-03	6.88E-02	6.60E-03
Naphthalene	AP-42	[4],[5]	1.30E-04	lb/MMBtu	8.79E-04	2.11E-02	2.02E-03	1.76E-03	4.22E-02	4.05E-03
Total VOC HAPs					**1.15E-02**	**2.76E-01**	**2.65E-02**	**2.30E-02**	**5.53E-01**	**5.31E-02**

[1] Representative engine specifications used from Apolytares Q88 vessel. Information received from Texas Gulf Terminals. Other vessels are expected to be smaller in capacity compared to the one represented here.

[2] Operating hours are assumed to be the same as that of the Carrier's main engine. Operating load of 60% is assumed.

[3] Emission factors based on AP-42, Chapter 3, Table 3.4-3, Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[4] Emission factors based on AP-42, Chapter 3, Table 3.4-4, PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[5] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

[6] Diesel is proposed as fuel for tug boats.

[7] Based on Engine Specification obtained from Manufacturer's website for Cummins QSK 60 MCRS Engine.
https://marine.cummins.com/MarineECM/MarineContent/SiteContent/en/Binary_Asset/attachments/Products/Commercial_Propulsion/QSK60_MCRS/QSK60_IMO_Tier_II_and_EPA_Tier_3_Certified_Ratings_SS.pdf

Sample Calculations:

Max LB/HR Emissions (Acrolein) = 0.000008 lb/MMBtu x 7000 Btu/Hp-hr / 1000000 x 1609.2 HP x 60% = 0.000053 lb/hr
Max Daily Emissions (Acrolein) = 0.000053 lb/hr x 24 hrs/day= 0.0013 lb/day
Annual Emissions (Acrolein) = 0.000053 lb/hr x 4608 hrs/yr / 2000 lb/ton= 0.000123 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Crude Carrier Auxiliary Engines
Greenhouse Gases

Engine Rating [1]	=	1,200	kW
		1,609	HP
Operating Time [2]	=	24	hrs/day
[2]		4,608	hrs/yr
Fuel Type [7]	=	Diesel	
Operating Load [2]	=	60.00%	

Pollutant	Emission Factor Basis		Emission Factor		Average Emissions from 1 engine [5]	Average Daily Emissions from 1 engine [5]	Annual Emissions from 1 engine	Average Emissions from all engines	Average Daily Emissions from all engines	Annual Emissions from all engines
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)	(lb/hr)	(lb/day)	(tons/yr)
CO_2	EPA	[3]	7.40E+01	kg/MMBtu	1,102	26,449	2,539	2,204	52,897	5,078
CH_4	EPA	[4]	3.00E-03	kg/MMBtu	0.04	1.07	0.10	0.09	2.15	0.21
N_2O	EPA	[4]	6.00E-04	kg/MMBtu	0.01	0.21	0.02	0.02	0.43	0.04
CO_2e	EPA	[6]	--	--	**1,106**	**26,539**	**2,548**	**2,212**	**53,079**	**5,096**

[1] Representative engine specifications used from Apolytares Q88 vessel. Information received from Texas Gulf Terminals. Other vessels are expected to be smaller in capacity compared to the one represented here.

[2] Operating hours are assumed to be the same as that of the Carrier's main engine. Operating load of 60% is assumed.

[3] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[4] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[5] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

[6] CH_4, CO_2 and N_2O are included in the emissions of CO_2 equivalent (CO_2e), weighted according to their global warming potential (GWP). The GWP was obtained from table A-1 to Subpart A of Part 98. This is consistent with TCEQ 2015 guidance: https://www.tceq.texas.gov/assets/public/permitting/air/factsheets/factsheets-psdghg-6291.pdf CH4 = 25, N2O = 298.

[7] Diesel is proposed as fuel for tug boats.

Sample Calculations:

Max LB/HR Emissions (CO2) = 73.96 kg/MMBtu x 2.20462 Lb/Kg /1000000 x 7000 Btu/hp-hr x 1609.2 HP x 60% = 1102 lb/hr
Max Daily Emissions (CO2) = 1102 lb/hr x 24 hrs/day= 26448.5094 lb/day
Annual Emissions (CO2) = 1102 lb/hr x 4608 hrs/yr / 2000 lb/ton= 2539 tpy
Total CO2e (tpy) = 5078 tpy CO2 x 1 + 0.21 tpy CH4 x 25 + 0.041 tpy N2O x 298 = 5096 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Crane Engines
Criteria Pollutants

Engine Rating [1], [4]	=	511	kW
		685	HP
Operating Time [2]	=	12	hrs/day
[2]		4,608	hrs/yr
Fuel Type [3]	=	Diesel	
Engine Speed [1]	=	2,000	rpm
Operating load [2]	=	100%	
Number of Cranes [1]		2	

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions from Crane Engines	Maximum Daily Emissions from Crane Engines	Annual Emissions from Crane Engines
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
PM	AP-42	[6]	7.00E-04	lb/HP-hr	0.96	11.51	2.21
PM_{10}	AP-42	[5]	4.01E-04	lb/HP-hr	0.55	6.59	1.27
$PM_{2.5}$	AP-42	[5]	3.89E-04	lb/HP-hr	0.53	6.40	1.23
NO_x	IMO Tier I	[4]	9.84E+00	g/kW-hr	22.16	265.96	51.06
SO_2	Fuel S Content	[3]	7.48E-04	lb/HP-hr	1.02	12.29	2.36
CO	AP-42	[6]	5.50E-03	lb/HP-hr	7.54	90.42	17.36
VOC	AP-42	[6],[8]	6.42E-04	lb/HP-hr	0.88	10.55	2.03
Pb	EPA	[7]	2.03E-07	lb/HP-hr	2.78E-04	3.34E-03	6.41E-04
H_2SO_4	Fuel S Content	[3]	2.34E-05	lb/HP-hr	3.20E-02	3.84E-01	7.37E-02

[1] Representative Crane engines assumed. Specifications used are from Cummins VTA -1710-C700 Diesel. RPM = 2000 RPM @ 685 HP.

[2] Assumed to operate for 12 hours a day. Total operating hours are assumed to be half of the carrier operating hours within the safety zone.

[3] Sulfur content of 0.1% is used per IMO standards for 2015. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO2 and 2 percent of sulfur in the fuel is oxidized to H2SO4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

[4] The engines comply with IMO I standards for NOx.

[5] PM_{10} and $PM_{2.5}$ emission factors based on AP-42 Chapter 3, Table 3.4-2, Particulate and Particle-sizing Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996). An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr. PM < 3um taken as $PM_{2.5}$. Total particulate emissions is the sum of filterable and condensable particulate emissions.

[6] Emission factors are based on AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996).

[7] Lead emission factor was obtained from EPA guidance document: Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2. Emission factor for distillate oil-fired gas turbines was used as a surrogate for distillate oil-fired engines due to lack of emission factors. An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr.

[8] Per footnote f of AP-42 Chapter 3, Table 3.4-1, non methane VOC emission factor has been taken as 91% of TOC emission factor.

Sample Calculations:

Max LB/HR Emissions (PM) = 2 x 0.0007 lb/HP-hr x 685 HP x 100% = 0.959 lb/hr
Max Daily Emissions (PM) = 0.959 lb/hr x 24 hrs/day= 11.508 lb/day
Annual Emissions (PM) = 0.959 lb/hr x 4608 hrs/yr / 2000 lb/ton= 2.2095 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Crane Engines
Hazardous Air Pollutants

Engine Rating [1], [7]	=	511	kW
		685	HP
Operating Time [2]	=	12	hrs/day
[2]		4,608	hrs/yr
Fuel Type [6]	=	Diesel	
Operating load [2]	=	100%	
Number of Cranes [1]		2	

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions from Crane Engines	Maximum Daily Emissions from Crane Engines	Annual Emissions from Crane Engines
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
Acetaldehyde	AP-42	[3],[5]	2.52E-05	lb/MMBtu	2.42E-04	2.90E-03	5.57E-04
Acrolein	AP-42	[3],[5]	7.88E-06	lb/MMBtu	7.56E-05	9.07E-04	1.74E-04
Benzene	AP-42	[3],[5]	7.76E-04	lb/MMBtu	7.44E-03	8.93E-02	1.71E-02
Formaldehyde	AP-42	[3],[5]	7.89E-05	lb/MMBtu	7.57E-04	9.08E-03	1.74E-03
Toluene	AP-42	[3],[5]	2.81E-04	lb/MMBtu	2.69E-03	3.23E-02	6.21E-03
Xylenes	AP-42	[3],[5]	1.93E-04	lb/MMBtu	1.85E-03	2.22E-02	4.26E-03
Total PAH	AP-42	[4],[5]	2.12E-04	lb/MMBtu	2.03E-03	2.44E-02	4.68E-03
Naphthalene	AP-42	[4],[5]	1.30E-04	lb/MMBtu	1.25E-03	1.50E-02	2.87E-03
Total VOC HAPs					**1.63E-02**	**1.96E-01**	**3.77E-02**

[1] Representative Crane engines assumed. Specifications used are from Cummins VTA -1710-C700 Diesel. RPM = 2000 RPM @ 685 HP.

[2] Assumed to operate for 12 hours a day. Total operating hours are assumed to be half of the carrier operating hours within the safety zone.

[3] Emission factors based on AP-42, Chapter 3, Table 3.4-3, Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[4] Emission factors based on AP-42, Chapter 3, Table 3.4-4, PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[5] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

[6] Diesel is proposed as fuel for this engine.

[7] Based on Engine Specification obtained from Manufacturer's website for Cummins QSK 60 MCRS Engine.
https://marine.cummins.com/MarineECM/MarineContent/SiteContent/en/Binary_Asset/attachments/Products/Commercial_Propulsion/QSK60_MCRS/QSK60_IMO_Tier_II_and_EPA_Tier_3_Certified_Ratings_SS.pdf

Sample Calculations:

Max LB/HR Emissions (Acrolein) = 2 x 0.000008 lb/MMBtu x 7000 Btu/Hp-hr / 1000000 x 685 HP x 100% = 0.000076 lb/hr
Max Daily Emissions (Acrolein) = 0.000076 lb/hr x 24 hrs/day= 0.0009 lb/day
Annual Emissions (Acrolein) = 0.000076 lb/hr x 4608 hrs/yr / 2000 lb/ton= 0.000174 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Crane Engines
Greenhouse Gases

Engine Rating [1]		511	KW
		685	HP
Operating Time [2]	=	12	hrs/day
		4608	hrs/year
Operating load [2]	=	100%	
Fuel Type [3]	=	Diesel	
Number of Cranes [1]		2	

Chemicals	Global Warming Potential (100 yr.)
CO_2	1
CH_4	25
N_2O	298

Pollutant	Emission Factor Basis		Emission Factor Value	Emission Factor Units	Maximum Hourly Emissions [7] (lb/hr)	Maximum Daily Emissions (lb/day)	Annual Emissions tpy
CO_2	40 CFR 98 Subpart C	[4]	73.96	kg/MMBtu	1,564	18,764	3,603
CH_4	40 CFR 98 Subpart C	[5]	3.00E-03	kg/MMBtu	0.06	0.76	0.15
N_2O	40 CFR 98 Subpart C	[5]	6.00E-04	kg/MMBtu	0.01	0.15	0.03
CO_2e	40 CFR 98 Subpart C	[6]	--	--	1,569	18,829	3,615

[1] Representative Crane engines assumed. Specifications used are from Cummins VTA -1710-C700 Diesel. RPM = 2000 RPM @ 685 HP.

[2] This is based on the worst-case assumption, this engine will operate maximum 12.0 hrs/day, 100 hrs per year. Operating Load is assumed to be 100%.

[3] Diesel is proposed as fuel for pilot boats.

[4] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[5] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[6] CH_4, CO_2 and N_2O are included in the emissions of CO_2 equivalent (CO_2e), weighted according to their global warming potential (GWP). The GWP was obtained from table A-1 to Subpart A of Part 98. This is consistent with TCEQ 2015 guidance: https://www.tceq.texas.gov/assets/public/permitting/air/factsheets/factsheets-psdghg-6291.pdf CH4 = 25, N2O = 298.

[7] An average Brake Specific Fuel Consumption (BFSC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Sample Calculations:

Max LB/HR Emissions (CO2) = 73.96 kg/MMBtu x 2.20462 Lb/Kg /1000000 x 7000 Btu/hp-hr x 685 HP x 100% = 1564 lb/hr
Max Daily Emissions (CO2) = 1564 lb/hr x 24 hrs/day= 18764.2192 lb/day
Annual Emissions (CO2) = 1564 lb/hr x 4608 hrs/yr / 2000 lb/ton= 3603 tpy
Total CO2e (tpy) = 3603 tpy CO2 x 1 + 0.15 tpy CH4 x 25 + 0.029 tpy N2O x 298 = 3615 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Carrier/VLCC Boilers
Criteria Pollutants

Rated Input [1]	=	3,407	Kg/hr
Rated Input [1]	=	149	MMBtu/hr
		1,064	Gal/hr
Conversion Factor [10]	=	140	MMBtu/10^3 gal
Operating Time [2]	=	24	hrs/day
[1]		4,608	hrs/yr
Fuel Type [8]	=	Diesel	
Number of Boilers [1]	=	1	

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions	Maximum Daily Emissions	Annual Emissions
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
PM	AP-42	[4]	3.30E+00	lb/10^3 gal	3.51	84.26	8.09
PM_{10}	AP-42	[5]	3.30E+00	lb/10^3 gal	3.51	84.26	8.09
$PM_{2.5}$	AP-42	[5]	3.30E+00	lb/10^3 gal	3.51	84.26	8.09
NO_x	AP-42	[3]	2.40E+01	lb/10^3 gal	25.53	612.79	58.83
SO_2	AP-42	[3]	1.42E+01	lb/10^3 gal	15.11	3.63E+02	3.48E+01
CO	AP-42	[3]	5.00E+00	lb/10^3 gal	5.32	127.66	12.26
VOC	AP-42	[6],[7]	2.00E-01	lb/10^3 gal	0.21	5.11E+00	4.90E-01
Pb	AP-42	[9]	9.00E+00	lb/10^{12} Btu	1.34E-03	3.22E-02	3.09E-03

[1] Representative boiler assumed. Specifications used are for Mitsubishi MAC-45 boiler as provided for Apolytares Q88 vessel.
Although there are two boilers but only one of them is used at any given time. This is based on the information given by Lloyds to Trinity Consultants on June 16 2018.

[2] Max operating time of 24 hr/day assumed, same as for the vessel in the safety zone. Total operating hours assumed to be the same as of the carrier's main engine.

[3] Based on AP-42 Section 1.3, Fuel Oil Combustion, Table 1.3-1 Emission Factors for No.2 fuel oil, p. 1.3-11,5/10. Weight % of sulfur in oil was estimated based on usage of Diesel as fuel containing 1000 ppm of sulfur content.

[4] Based on AP-42 Section 1.3, Fuel Oil Combustion, Table 1.3-1and Table 1.3-2, Emission Factors for No.2 fuel oil was used. Total particulate emissions is the sum of filterable and total condensable particulate emissions.

[5] All PM is assumed to be < 1 um, therefore, assumed PM2.5 = PM10 = PM.

[6] Based on AP-42 Section 1.3, Fuel Oil Combustion, Table 1.3-3, Industrial Boilers NMTOC Emission Factors for Distillate fuel oil was used, p. 1.3-14, 5/10.

[7] All NMTOC is assumed to be VOC.

[8] Diesel is proposed as fuel for the boiler.

[9] Based on AP-42 Section 1.3, Fuel Oil Combustion, Table 1.3-10, Emission Factors for Distillate fuel oil was used, p. 1.3-22,5/10.

[10 Based on AP-42 Section 1.3, Fuel Oil Combustion, Section 1.3.4.3, p. 1.3-8, 5/10. 1 l diesel = 1.88 lb.

Sample Calculations:

Max LB/HR Emissions (PM) = 3.3 lb/1000 gal x 1063.87 gal/hr x 1 = 3.5108 lb/hr
Max Daily Emissions (PM) = 3.5108 lb/hr x 24 hrs/day= 84.2585 lb/day
Annual Emissions (PM) = 3.5108 lb/hr x 4608 hrs/yr / 2000 lb/ton= 8.0888 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Carrier/VLCC Boilers
Hazardous Air Pollutants

Rated Input [1]	=	149	MMBtu/hr
Conversion Factor [5]	=	140	MMBtu/10^3 gal
Operating Time [2]	=	24	hrs/day
[1]		4,608	hrs/yr
Fuel Type [4]	=	Diesel	
Number of Boilers [1]	=	1	

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions	Maximum Daily Emissions	Annual Emissions
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
Formaldehyde	AP-42	[3]	6.10E-02	lb/10^3 gal	6.49E-02	1.56E+00	1.50E-01
Benzene	AP-42	[3]	2.14E-04	lb/10^3 gal	2.28E-04	5.46E-03	5.25E-04
Toluene	AP-42	[3]	6.20E-03	lb/10^3 gal	6.60E-03	1.58E-01	1.52E-02
Xylenes	AP-42	[3]	1.09E-04	lb/10^3 gal	1.16E-04	2.78E-03	2.67E-04
1,1,1 - Trichloroethane	AP-42	[3]	2.36E-04	lb/10^3 gal	2.51E-04	6.03E-03	5.78E-04
Naphthalene	AP-42	[3]	1.13E-03	lb/10^3 gal	1.20E-03	2.89E-02	2.77E-03
POM	AP-42	[3]	3.30E-03	lb/10^3 gal	3.51E-03	8.43E-02	8.09E-03
Total VOC HAPs					**7.33E-02**	**1.76E+00**	**1.69E-01**

[1] Representative boiler assumed. Specifications used are for Mitsubishi MAC-45 boiler as provided for Apolytares Q88 vessel.
[2] Max operating time of 24 hr/day assumed, same as for the vessel in the safety zone. Total operating hours assumed to be the same as of the carrier's main engine.
[3] Based on AP-42 Section 1.3, Fuel Oil Combustion, Table 1.3-8 and 1.3-9, Emission Factors for Distillate fuel oil was used, p. 1.3-20,5/10.
[4] Diesel is proposed as fuel for the boiler.
[5] Based on AP-42 Section 1.3, Fuel Oil Combustion, Section 1.3.4.3, p. 1.3-8, 5/10.

Sample Calculations:

Max LB/HR Emissions (Formaldehyde) = 2 x 0.061 MMBtu/hr / 140 MMBtu/1000 gal x 149 lb/1000 gal = 0.06 lb/hr
Max Daily Emissions (Formaldehyde) = 0.06 lb/hr x 24 hrs/day= 1.5575 lb/day
Annual Emissions (Formaldehyde) = 0.06 lb/hr x 4608 hrs/yr / 2000 lb/ton= 0.1495 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Carrier/VLCC Boilers
Greenhouse Gases

Rated Input [1]	=	149	MMBtu/hr
Conversion Factor [5]	=	140	MMBtu/10^3 gal
Operating Time [2]	=	24	hrs/day
[1]		4608	hrs/yr
Fuel Type [7]	=	Diesel	
Number of Boilers [1]	=	1	

Pollutant	Emission Factor Basis		Emission Factor		Average Emissions [5]	Average Daily Emissions	Annual Emissions
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
CO_2	40 CFR 98 Subpart C	[3]	7.40E+01	kg/MMBtu	24,286	582,852	55,954
CH_4	40 CFR 98 Subpart C	[4]	3.00E-03	kg/MMBtu	0.99	23.64	2.27
N_2O	40 CFR 98 Subpart C	[4]	6.00E-04	kg/MMBtu	0.20	4.73	0.45
CO_2e	40 CFR 98 Subpart C	[6]	--	--	24,369	584,852	56,146

[1] Representative boiler assumed. Specifications used are for Mitsubishi MAC-45 boiler as provided for Apolytares Q88 vessel.

[2] Max operating time of 24 hr/day assumed, same as for the vessel in the safety zone. Total operating hours assumed to be the same as of the carrier's main engine.

[3] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[4] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[5] Based on AP-42 Section 1.3, Fuel Oil Combustion, Section 1.3.4.3, p. 1.3-8, 5/10.

[6] CH_4, CO_2 and N_2O are included in the emissions of CO_2 equivalent (CO_2e), weighted according to their global warming potential (GWP). The GWP was obtained from table A-1 to Subpart A of Part 98. This is consistent with TCEQ 2015 guidance: https://www.tceq.texas.gov/assets/public/permitting/air/factsheets/factsheets-psdghg-6291.pdf

[7] Diesel is proposed as fuel for the boiler

Sample Calculations:

Max LB/HR Emissions (CO2) = 73.96 kg/MMBtu x 2.20462 Lb/Kg x 148.94 MMBtu/Hr / 140 MMBtu/1000 gal = 24286 lb/hr
Max Daily Emissions (CO2) = 24286 lb/hr x 24 hrs/day= 582852 lb/day
Annual Emissions (CO2) = 24286 lb/hr x 4608 hrs/yr / 2000 lb/ton= 55954 tpy
Total CO2e (tpy) = 55954 tpy CO2 x 1 + 2.27 tpy CH4 x 25 + 0.454 tpy N2O x 298 = 56146 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Representative Cargo Pump Engines
Criteria Pollutants

Engine Rating [1]	=	1,678	kW
		2,250	HP
Operating Time [2]	=	24	hrs/day
		4,608	hrs/yr
Fuel Type [3]	=	Diesel	
Operating load [2]	=	100%	
No of representative engines [2]	=	3	

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions	Maximum Daily Emissions	Annual Emissions
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
PM	AP-42	[5]	7.00E-04	lb/HP-hr	4.73	113.40	10.89
PM_{10}	AP-42	[4]	4.01E-04	lb/HP-hr	2.71	64.98	6.24
$PM_{2.5}$	AP-42	[4]	3.89E-04	lb/HP-hr	2.63	63.05	6.05
NO_x	AP-42	[5]	2.40E-02	lb/HP-hr	162.00	3888.00	373.25
SO_2	Fuel S Content	[3]	7.48E-04	lb/HP-hr	5.05E+00	1.21E+02	1.16E+01
CO	AP-42	[5]	5.50E-03	lb/HP-hr	37.13	891.00	85.54
VOC	AP-42	[5],[7]	6.42E-04	lb/HP-hr	4.33	103.93	9.98
Pb	EPA	[6]	2.03E-07	lb/HP-hr	1.37E-03	3.29E-02	3.16E-03
H_2SO_4	Fuel S Content	[3]	2.34E-05	lb/HP-hr	1.58E-01	3.78E+00	3.63E-01

[1] Representative engine specifications used from Apolytares Q88 vessel Information. Details received from Texas Gulf Terminals (TGT). Fuel consumption rates for these 3 pumps are not available and therefore assumed.

[2] A total of 3 engines represent the combined cargo pumping capacity. TGT proposes to utilize same or equivalent pumps or any equivalent combination of number and capacity of pumps.

[3] Sulfur content of 1000 ppm is used for emission calculations per IMO standards for 2015. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO2 and 2 percent of sulfur in the fuel is oxidized to H2SO4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

[4] PM_{10} and $PM_{2.5}$ emission factors based on AP-42 Chapter 3, Table 3.4-2, Particulate and Particle-sizing Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996). An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr. PM < 3um taken as $PM_{2.5}$. Total particulate emissions is the sum of filterable and condensable particulate emissions.

[5] Emission factors are based on AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996).

[6] Lead emission factor was obtained from EPA guidance document: Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2. Emission factor for distillate oil-fired gas turbines was used as a surrogate for distillate oil-fired engines due to lack of emission factors. An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr.

[7] Per footnote f of AP-42 Chapter 3, Table 3.4-1, non methane VOC emission factor has been taken as 91% of TOC emission factor.

Sample Calculations:

Max LB/HR Emissions (PM) = 3 x 0.0007 lb/HP-hr x 2250 HP x 100% = 4.725 lb/hr
Max Daily Emissions (PM) = 4.725 lb/hr x 24 hrs/day= 113.4 lb/day
Annual Emissions (PM) = 4.725 lb/hr x 4608 hrs/yr / 2000 lb/ton= 10.8864 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Representative Cargo Pump Engines
Hazardous Air Pollutants

Engine Rating [1]	=	1,678	kW
		2,250	HP
Operating Time [2]	=	24	hrs/day
		4,608	hrs/yr
Fuel Type [6]	=	Diesel	
Operating load [2]	=	100%	
No of representative engines [2]	=	3	

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions	Maximum Daily Emissions	Annual Emissions
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
Acetaldehyde	AP-42	[3],[5]	2.52E-05	lb/MMBtu	1.19E-03	2.86E-02	2.74E-03
Acrolein	AP-42	[3],[5]	7.88E-06	lb/MMBtu	3.72E-04	8.94E-03	8.58E-04
Benzene	AP-42	[3],[5]	7.76E-04	lb/MMBtu	3.67E-02	8.80E-01	8.45E-02
Formaldehyde	AP-42	[3],[5]	7.89E-05	lb/MMBtu	3.73E-03	8.95E-02	8.59E-03
Toluene	AP-42	[3],[5]	2.81E-04	lb/MMBtu	1.33E-02	3.19E-01	3.06E-02
Xylenes	AP-42	[3],[5]	1.93E-04	lb/MMBtu	9.12E-03	2.19E-01	2.10E-02
Total PAH	AP-42	[4],[5]	2.12E-04	lb/MMBtu	1.00E-02	2.40E-01	2.31E-02
Naphthalene	AP-42	[4],[5]	1.30E-04	lb/MMBtu	6.14E-03	1.47E-01	1.42E-02
Total VOC HAPs					**8.05E-02**	**1.93E+00**	**1.86E-01**

[1] Representative engine specifications used from Apolytares Q88 vessel Information. Details received from Texas Gulf Terminals (TGT). Fuel consumption rates for these 3 pumps are not available and therefore assumed.

[2] A total of 3 engines represent the combined cargo pumping capacity. TGT proposes to utilize same or equivalent pumps or any equivalent combination of number and capacity of pumps.

[3] Emission factors based on AP-42, Chapter 3, Table 3.4-3, Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[4] Emission factors based on AP-42, Chapter 3, Table 3.4-4, PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[5] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

[6] Diesel is proposed as fuel for these pumps.

Sample Calculations:

Max LB/HR Emissions (Acetaldehyde) = 3 x 0.000025 lb/MMBtu x 7000 Btu/Hp-hr / 1000000 x 2250 HP x 100% = 0.001191 lb/hr
Max Daily Emissions (Acetaldehyde) = 0.001191 lb/hr x 24 hrs/day= 0.0286 lb/day
Annual Emissions (Acetaldehyde) = 0.001191 lb/hr x 4608 hrs/yr / 2000 lb/ton= 0.002743 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Representative Cargo Pump Engines
Greenhouse Gases

Engine Rating [1]	=	1,678	kW
		2,250	HP
Operating Time [2]	=	24	hrs/day
		4,608	hrs/yr
Fuel Type [7]	=	Diesel	
Operating load [2]	=	100%	
No of representative engines [2]	=	3	

Pollutant	Emission Factor Basis		Emission Factor		Average Emissions [5]	Average Daily Emissions	Annual Emissions
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
CO_2	40 CFR 98 Subpart C	[3]	7.40E+01	kg/MMBtu	7,704	184,903	17,751
CH_4	40 CFR 98 Subpart C	[4]	3.00E-03	kg/MMBtu	0.31	7.50	0.72
N_2O	40 CFR 98 Subpart C	[4]	6.00E-04	kg/MMBtu	0.06	1.50	0.14
CO_2e	40 CFR 98 Subpart C	[6]	--	--	7,731	185,537	17,812

[1] Representative engine specifications used from Apolytares Q88 vessel Information. Details received from Texas Gulf Terminals (TGT). Fuel consumption rates for these 3 pumps are not available and therefore assumed.

[2] A total of 3 engines represent the combined cargo pumping capacity. TGT proposes to utilize same or equivalent pumps or any equivalent combination of number and capacity of pumps.

[3] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[4] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[5] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

[6] CH_4, CO_2 and N_2O are included in the emissions of CO_2 equivalent (CO_2e), weighted according to their global warming potential (GWP). The GWP was obtained from table A-1 to Subpart A of Part 98. This is consistent with TCEQ 2015 guidance: https://www.tceq.texas.gov/assets/public/permitting/air/factsheets/factsheets-psdghg-6291.pdf
CH4 = 25, N2O = 298

[7] Diesel is proposed as fuel for Cargo Pumps.

Sample Calculations:

Max LB/HR Emissions (CO2) = 3 x 73.96 kg/MMBtu x 2.20462 Lb/Kg /1000000 x 7000 Btu/hp-hr x 2250 HP x 100% = 7704 lb/hr
Max Daily Emissions (CO2) = 7704 lb/hr x 24 hrs/day= 184902.9 lb/day
Annual Emissions (CO2) = 7704 lb/hr x 4608 hrs/yr / 2000 lb/ton= 17751 tpy
Total CO2e (tpy) = 17751 tpy CO2 x 1 + 0.72 tpy CH4 x 25 + 0.144 tpy N2O x 298 = 17812 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Representative Stripping Pump Engine
Criteria Pollutants

Engine Rating [1]	=	134	kW
		180	HP
Operating Time [2]	=	24	hrs/day
		4,608	hrs/yr
Fuel Type [3]	=	Diesel	
Operating load [2]	=	100%	
No of representative engines [2]	=	1	

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions	Maximum Daily Emissions	Annual Emissions
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
PM	AP-42	[5]	7.00E-04	lb/HP-hr	0.13	3.02	0.29
PM_{10}	AP-42	[4]	4.01E-04	lb/HP-hr	0.07	1.73	0.17
$PM_{2.5}$	AP-42	[4]	3.89E-04	lb/HP-hr	0.07	1.68	0.16
NO_x	AP-42	[5]	2.40E-02	lb/HP-hr	4.32	103.68	9.95
SO_2	Fuel S Content	[3]	7.48E-04	lb/HP-hr	1.35E-01	3.23E+00	3.10E-01
CO	AP-42	[5]	5.50E-03	lb/HP-hr	0.99	23.76	2.28
VOC	AP-42	[5],[7]	6.42E-04	lb/HP-hr	0.12	2.77	0.27
Pb	EPA	[6]	2.03E-07	lb/HP-hr	3.65E-05	8.77E-04	8.42E-05
H_2SO_4	Fuel S Content	[3]	2.34E-05	lb/HP-hr	4.20E-03	1.01E-01	9.69E-03

[1] Representative engine specifications used from Apolytares Q88 vessel Information. Details received from Texas Gulf Terminals (TGT). Fuel consumption rates for this pump is not available and therefore assumed.

[2] A total of 1 engines represent the combined stripping capacity. TGT proposes to utilize same or equivalent pumps or any equivalent combination of number and capacity of pumps.

[3] Sulfur content of 0.1% is used per IMO standards for 2015. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO2 and 2 percent of sulfur in the fuel is oxidized to H2SO4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

[4] PM_{10} and $PM_{2.5}$ emission factors based on AP-42 Chapter 3, Table 3.4-2, Particulate and Particle-sizing Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996). An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr. PM < 3um taken as $PM_{2.5}$. Total particulate emissions is the sum of filterable and condensable particulate emissions.

[5] Emission factors are based on AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996).

[6] Lead emission factor was obtained from EPA guidance document: Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2. Emission factor for distillate oil-fired gas turbines was used as a surrogate for distillate oil-fired engines due to lack of emission factors. An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr.

[7] Per footnote f of AP-42 Chapter 3, Table 3.4-1, non methane VOC emission factor has been taken as 91% of TOC emission factor.

Sample Calculations:

Max LB/HR Emissions (PM) = 3 x 0.0007 lb/HP-hr x 180 HP x 100% = 0.126 lb/hr
Max Daily Emissions (PM) = 0.126 lb/hr x 24 hrs/day= 3.024 lb/day
Annual Emissions (PM) = 0.126 lb/hr x 4608 hrs/yr / 2000 lb/ton= 0.2903 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Representative Stripping Pump Engine
Hazardous Air Pollutants

Engine Rating [1]	=	134	kW
		180	HP
Operating Time [2]	=	24	hrs/day
		4,608	hrs/yr
Fuel Type [6]	=	Diesel	
Operating load [2]	=	100%	
No of representative engines [2]	=	1	

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions	Maximum Daily Emissions	Annual Emissions
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
Acetaldehyde	AP-42	[3],[5]	2.52E-05	lb/MMBtu	3.18E-05	7.62E-04	7.32E-05
Acrolein	AP-42	[3],[5]	7.88E-06	lb/MMBtu	9.93E-06	2.38E-04	2.29E-05
Benzene	AP-42	[3],[5]	7.76E-04	lb/MMBtu	9.78E-04	2.35E-02	2.25E-03
Formaldehyde	AP-42	[3],[5]	7.89E-05	lb/MMBtu	9.94E-05	2.39E-03	2.29E-04
Toluene	AP-42	[3],[5]	2.81E-04	lb/MMBtu	3.54E-04	8.50E-03	8.16E-04
Xylenes	AP-42	[3],[5]	1.93E-04	lb/MMBtu	2.43E-04	5.84E-03	5.60E-04
Total PAH	AP-42	[4],[5]	2.12E-04	lb/MMBtu	2.67E-04	6.41E-03	6.15E-04
Naphthalene	AP-42	[4],[5]	1.30E-04	lb/MMBtu	1.64E-04	3.93E-03	3.77E-04
Total VOC HAPs					**2.15E-03**	**5.15E-02**	**4.95E-03**

[1] Representative engine specifications used from Apolytares Q88 vessel Information. Details received from Texas Gulf Terminals (TGT). Fuel consumption rates for this pump is not available and therefore assumed.

[2] A total of 1 engines represent the combined stripping capacity. TGT proposes to utilize same or equivalent pumps or any equivalent combination of number and capacity of pumps.

[3] Emission factors based on AP-42, Chapter 3, Table 3.4-3, Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[4] Emission factors based on AP-42, Chapter 3, Table 3.4-4, PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[5] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

[6] Diesel is proposed as fuel for these pumps.

Sample Calculations:

Max LB/HR Emissions (Acetaldehyde) = 3 x 0.000025 lb/MMBtu x 7000 Btu/Hp-hr / 1000000 x 180 HP x 100% = 0.000032 lb/hr
Max Daily Emissions (Acetaldehyde) = 0.000032 lb/hr x 24 hrs/day= 0.0008 lb/day
Annual Emissions (Acetaldehyde) = 0.000032 lb/hr x 4608 hrs/yr / 2000 lb/ton= 0.000073 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Representative Stripping Pump Engine
Greenhouse Gases

Engine Rating [1]	=	134	kW
		180	HP
Operating Time [2]	=	24	hrs/day
		4,608	hrs/yr
Fuel Type [7]	=	Diesel	
Operating load [2]	=	100%	
No of representative engines [2]	=	1	

Pollutant	Emission Factor Basis		Emission Factor		Average Emissions [5]	Average Daily Emissions	Annual Emissions
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
CO_2	40 CFR 98 Subpart C	[3]	7.40E+01	kg/MMBtu	205	4,931	473
CH_4	40 CFR 98 Subpart C	[4]	3.00E-03	kg/MMBtu	8.33E-03	2.00E-01	1.92E-02
N_2O	40 CFR 98 Subpart C	[4]	6.00E-04	kg/MMBtu	1.67E-03	4.00E-02	3.84E-03
CO_2e	40 CFR 98 Subpart C	[6]	--	--	206	4,948	475

[1] Representative engine specifications used from Apolytares Q88 vessel Information. Details received from Texas Gulf Terminals (TGT). Fuel consumption rates for this pump is not available and therefore assumed.

[2] A total of 1 engines represent the combined stripping capacity. TGT proposes to utilize same or equivalent pumps or any equivalent combination of number and capacity of pumps.

[3] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[4] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[5] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

[6] CH_4, CO_2 and N_2O are included in the emissions of CO_2 equivalent (CO_2e), weighted according to their global warming potential (GWP). The GWP was obtained from table A-1 to Subpart A of Part 98. This is consistent with TCEQ 2015 guidance: https://www.tceq.texas.gov/assets/public/permitting/air/factsheets/factsheets-psdghg-6291.pdf

[7] Diesel is proposed as fuel for the pumps.

Sample Calculations:

Max LB/HR Emissions (CO2) = 1 x 73.96 kg/MMBtu x 2.20462 Lb/Kg /1000000 x 7000 Btu/hp-hr x 180 HP x 100% = 205 lb/hr
Max Daily Emissions (CO2) = 205 lb/hr x 24 hrs/day= 4930.7 lb/day
Annual Emissions (CO2) = 205 lb/hr x 4608 hrs/yr / 2000 lb/ton= 473 tpy
Total CO2e (tpy) = 473 tpy CO2 x 1 + 0.02 tpy CH4 x 25 + 0.004 tpy N2O x 298 = 475 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Representative Ballast Pump Engines
Criteria Pollutants

Engine Rating [1]	=	1,007	kW
		1,350	HP
Operating Time [2]	=	24	hrs/day
		4,608	hrs/yr
Fuel Type [3]	=	Diesel	
Operating load [2]	=	100%	
No of representative engines [2]	=	2	

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions	Maximum Daily Emissions	Annual Emissions
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
PM	AP-42	[5]	7.00E-04	lb/HP-hr	1.89	45.36	4.35
PM_{10}	AP-42	[4]	4.01E-04	lb/HP-hr	1.08	25.99	2.50
$PM_{2.5}$	AP-42	[4]	3.89E-04	lb/HP-hr	1.05	25.22	2.42
NO_x	AP-42	[5]	2.40E-02	lb/HP-hr	64.80	1555.20	149.30
SO_2	Fuel S Content	[3]	7.48E-04	lb/HP-hr	2.02E+00	4.85E+01	4.65E+00
CO	AP-42	[5]	5.50E-03	lb/HP-hr	14.85	356.40	34.21
VOC	AP-42	[5],[7]	6.42E-04	lb/HP-hr	1.73	41.57	3.99
Pb	EPA	[6]	2.03E-07	lb/HP-hr	5.48E-04	1.32E-02	1.26E-03
H_2SO_4	Fuel S Content	[3]	2.34E-05	lb/HP-hr	6.31E-02	1.51E+00	1.45E-01

[1] Representative engine specifications used from Apolytares Q88 vessel Information. Details received from Texas Gulf Terminals (TGT). Fuel consumption rates for this pump is not available and therefore assumed.

[2] A total of 1 engines represent the combined stripping capacity. TGT proposes to utilize same or equivalent pumps or any equivalent combination of number and capacity of pumps.

[3] Sulfur content of 0.1% is used for all diesel combustion sources per IMO standards for 2015. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO2 and 2 percent of sulfur in the fuel is oxidized to H2SO4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

[4] PM_{10} and $PM_{2.5}$ emission factors based on AP-42 Chapter 3, Table 3.4-2, Particulate and Particle-sizing Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996). An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr. PM < 3um taken as $PM_{2.5}$. Total particulate emissions is the sum of filterable and condensable particulate emissions.

[5] Emission factors are based on AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996).

[6] Lead emission factor was obtained from EPA guidance document: Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2. Emission factor for distillate oil-fired gas turbines was used as a surrogate for distillate oil-fired engines due to lack of emission factors. An average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr.

[7] Per footnote f of AP-42 Chapter 3, Table 3.4-1, non methane VOC emission factor has been taken as 91% of TOC emission factor.

Sample Calculations:

Max LB/HR Emissions (PM) = 2 x 0.0007 lb/HP-hr x 1350 HP x 100% = 1.89 lb/hr
Max Daily Emissions (PM) = 1.89 lb/hr x 24 hrs/day= 45.36 lb/day
Annual Emissions (PM) = 1.89 lb/hr x 4608 hrs/yr / 2000 lb/ton= 4.3546 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Representative Ballast Pump Engines
Hazardous Air Pollutants

Engine Rating [1]	=	1,007	kW
		1,350	HP
Operating Time [2]	=	24	hrs/day
		4,608	hrs/yr
Fuel Type [6]	=	Diesel	
Operating load [2]	=	100%	
No of representative engines [2]	=	2	

Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions	Maximum Daily Emissions	Annual Emissions
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
Acetaldehyde	AP-42	[3],[5]	2.52E-05	lb/MMBtu	4.76E-04	1.14E-02	1.10E-03
Acrolein	AP-42	[3],[5]	7.88E-06	lb/MMBtu	1.49E-04	3.57E-03	3.43E-04
Benzene	AP-42	[3],[5]	7.76E-04	lb/MMBtu	1.47E-02	3.52E-01	3.38E-02
Formaldehyde	AP-42	[3],[5]	7.89E-05	lb/MMBtu	1.49E-03	3.58E-02	3.44E-03
Toluene	AP-42	[3],[5]	2.81E-04	lb/MMBtu	5.31E-03	1.27E-01	1.22E-02
Xylenes	AP-42	[3],[5]	1.93E-04	lb/MMBtu	3.65E-03	8.75E-02	8.40E-03
Total PAH	AP-42	[4],[5]	2.12E-04	lb/MMBtu	4.01E-03	9.62E-02	9.23E-03
Naphthalene	AP-42	[4],[5]	1.30E-04	lb/MMBtu	2.46E-03	5.90E-02	5.66E-03
Total VOC HAPs					**3.22E-02**	**7.73E-01**	**7.42E-02**

[1] Representative engine specifications used from Apolytares Q88 vessel Information. Details received from Texas Gulf Terminals (TGT). Fuel consumption rates for this pump is not available and therefore assumed.

[2] A total of 1 engines represent the combined stripping capacity. TGT proposes to utilize same or equivalent pumps or any equivalent combination of number and capacity of pumps.

[3] Emission factors based on AP-42, Chapter 3, Table 3.4-3, Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[4] Emission factors based on AP-42, Chapter 3, Table 3.4-4, PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[5] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

[6] Diesel is proposed as fuel for these pumps.

Sample Calculations:

Max LB/HR Emissions (Acetaldehyde) = 2 x 0.000025 lb/MMBtu x 7000 Btu/Hp-hr / 1000000 x 1350 HP x 100% = 0.000476 lb/l
Max Daily Emissions (Acetaldehyde) = 0.000476 lb/hr x 24 hrs/day= 0.0114 lb/day
Annual Emissions (Acetaldehyde) = 0.000476 lb/hr x 4608 hrs/yr / 2000 lb/ton= 0.001097 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations

Representative Ballast Pump Engines
Greenhouse Gases

Engine Rating [1]	=	1,007	kW
		1,350	HP
Operating Time [2]	=	24	hrs/day
		4,608	hrs/yr
Fuel Type [7]	=	Diesel	
Operating load [2]	=	100%	
No of representative engines [2]	=	2	

Pollutant	Emission Factor Basis		Emission Factor		Average Emissions [5]	Average Daily Emissions	Annual Emissions
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)
CO_2	40 CFR 98 Subpart C	[3]	7.40E+01	kg/MMBtu	3,082	73,961	7,100
CH_4	40 CFR 98 Subpart C	[4]	3.00E-03	kg/MMBtu	1.25E-01	3.00E+00	2.88E-01
N_2O	40 CFR 98 Subpart C	[4]	6.00E-04	kg/MMBtu	2.50E-02	6.00E-01	5.76E-02
CO_2e	40 CFR 98 Subpart C	[6]	--	--	3,092	74,215	7,125

[1] Representative engine specifications used from Apolytares Q88 vessel Information. Details received from Texas Gulf Terminals (TGT). Fuel consumption rates for this pump is not available and therefore assumed.

[2] A total of 1 engines represent the combined stripping capacity. TGT proposes to utilize same or equivalent pumps or any equivalent combination of number and capacity of pumps.

[3] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[4] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[5] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

[6] CH_4, CO_2 and N_2O are included in the emissions of CO_2 equivalent (CO_2e), weighted according to their global warming potential (GWP). The GWP was obtained from table A-1 to Subpart A of Part 98. This is consistent with TCEQ 2015 guidance: https://www.tceq.texas.gov/assets/public/permitting/air/factsheets/factsheets-psdghg-6291.pdf

[7] Diesel is proposed as fuel for the pumps.

Sample Calculations:

Max LB/HR Emissions (CO2) = 2 x 73.96 kg/MMBtu x 2.20462 Lb/Kg /1000000 x 7000 Btu/hp-hr x 1350 HP x 100% = 3082 lb/hr
Max Daily Emissions (CO2) = 3082 lb/hr x 24 hrs/day= 73961.2 lb/day
Annual Emissions (CO2) = 3082 lb/hr x 4608 hrs/yr / 2000 lb/ton= 7100 tpy
Total CO2e (tpy) = 7100 tpy CO2 x 1 + 0.29 tpy CH4 x 25 + 0.058 tpy N2O x 298 = 7125 tpy

SO_2 and H_2SO_4 EF Calculation

Diesel - SO_2 Emission Factor Calculation - Mass Balance

Sulfur Content of Diesel[1]	Conversion Factor	Density of Diesel[2]	Diesel Heat Value[3]	Engine Efficiency[4]	Conversion of S in fuel to SO_2 in exhaust[5]		SO_2 Emission Factor	
1000	0.98	7.05	1.00	7,000	64.1	=	7.48E-04	1.07E-01
ppm S	lb of S	lb of diesel	gal. of diesel	btu	lb/lb-mol of SO_2		lb	lb
	1.00E+06	1	129,226.50	1	32.1		1	1
	lb of diesel - ppm S	gal. of diesel	btu	hp-hr	lb/lb-mol of S		hp-hr	MMBtu

[1] Based on IMO 2015 Standards for Sulfur - https://www.dieselnet.com/standards/inter/imo.php
[2] AP-42, Appendix A, Page A-7.
[3] Heating value is obtained from Chevron Diesel Fuels Technical Review Table 4.3.
[4] AP-42, Table 3.4-1, footnote e.
[5] Per Section 4.1.1 of *Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines*, EPA420-R-03-008, April 2003, 98% of sulfur in the fuel is assumed to be converted into SO_2.

Diesel - H_2SO_4 Emission Factor Calculation - Mass Balance

Sulfur Content of Diesel[1]	Conversion Factor	Density of Diesel[2]	Diesel Heat Value[3]	Engine Efficiency[4]	Conversion of S in fuel to H_2SO_4 in exhaust[5]		H_2SO_4 Emission Factor	
1000	0.02	7.05	1.00	7,000	98.1	=	2.34E-05	3.34E-03
ppm S	lb of S	lb of diesel	gal. of diesel	btu	lb/lb-mol of H_2SO_4		lb	lb
	1.00E+06	1	129,226.50	1	32.1		1	1
	lb of diesel - ppm S	gal. of diesel	btu	hp-hr	lb/lb-mol of S		hp-hr	MMBtu

[1] Based on IMO 2015 Standards for Sulfur - https://www.dieselnet.com/standards/inter/imo.php
[2] AP-42, Appendix A, Page A-7.
[3] Heating value is obtained from Chevron Diesel Fuels Technical Review Table 4.3.
[4] AP-42, Table 3.4-1, footnote e.
[5] Per Section 4.1.1 of *Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines*, EPA420-R-03-008, April 2003, 2 % of sulfur in the fuel is conservatively assumed to be converted into H_2SO_4.

LIGHTERING OPERATIONS ALTERNATIVE SCENARIO EMISSION CALCULATIONS

Tables A-48 to A-55

Alternative Analysis Emissions Summary

Description of Activity	VOC tpy	NOx tpy	CO tpy	PM tpy	PM_{10} tpy	$PM_{2.5}$ tpy	SO_2 tpy	H_2SO_4 tpy	H_2S tpy	Total HAPs tpy	CO2e tpy
Proposed Project Design											
Crude Carrier, Support Vessels & Boats	47	1673	343	69.1	54.9	52.1	87.6	1.65	0.00	1.1	134484
Crude Carrier Loading	10808								0.24	200.0	
Proposed Project Design - Total	**10855**	**1673**	**343**	**69.1**	**54.9**	**52.1**	**87.6**	**1.65**	**0.24**	**201**	**134484**
Alternative Project Designs (Lightering) [1]											
VLCC completely loaded offshore - 3 AFRAMAX carriers load onshore, travel 65 miles [2] and then unload to VLCC											
Crude Carrier, Support Vessels & Boats	47	1,673	343	69.1	54.9	52.1	87.6	1.65	0.00	1.1	134484
Crude Carrier Loading	10808								0.24	200.0	
Lightering Loading	215	39	79	3.0	3.0	3.0	0.8		0.00	4.0	64757
Lightering Transit	2718								0.07	52.5	
Lightering Vessel Propulsion	28	1,410	128	53.4	53.4	49.1	32.8	1.03		0.5	50278
Additional Tugs/Support Ships [3]	5	94	41	5.1	3.0	2.9	5.5	0.17		0.1	8383
Complete Lightering	*13821*	*3,217*	*590*	*130.6*	*114.3*	*107.0*	*126.8*	*2.85*	*0.31*	*258*	*257903*
VLCC partially loaded inland and remaining loaded offshore - VLCC loads up to 50% capacity at shore; and Suezmax vessel fills the remaining 50% of the VLCC offshore [2].											
Crude carrier, Support Vessels & Boats	47	1,673	343	69.1	54.9	52.1	87.6	1.65	0.00	1.1	134,484
Crude Carrier Loading	5511								0.12	102.0	
Lightering Loading	108	20	39	1.5	1.5	1.5	0.4	0.00	0.00	2.0	32,378
Lightering Transit	2718								0.07	52.5	
Lightering Vessel Propulsion	13	627	57	23.7	23.7	21.8	14.6	0.46		0.2	22,346
Additional Tugs/Support Ships [3]	5	94	41	5.1	3.0	2.9	5.5	0.17	0.00	0.1	8,383
Partial Lightering	*8401*	*2,413*	*480*	*99.4*	*83.1*	*78.3*	*108.1*	*2.28*	*0.19*	*158*	*197,592*

Alternative Lightering Scenario Total [1]	**13279**	**3136**	**579**	**127.5**	**111.2**	**104.2**	**124.9**	**2.79**	**0.29**	**248**	**251871**
Emissions Reduction (TPY) from Proposed SPM Design	**2424**	**1463**	**236**	**58**	**56**	**52**	**37**	**1.1**	**0.1**	**47**	**117387**

[1] Alternative Lightering scenario shown uses a combination of complete and partial lightering. Totals show a 90% emission contribution from 100% capacity loaded offshore "Complete Lightering" and 10% contribusion from partially loaded capacity "Partial Lightering" for comparison purposes.
[2] The shortest distance between the shore and SPM location is 15 miles but the distance travelled is not straight and estimated to be 65 miles one way.
[3] The alternative lightering scenario assumes that one additional tug boat is needed for servicing the AFRAMAX, SUEZMAX and VLCCs with operating conditions similar to the tug boats proposed for normal operation. The emissions shown here are the sum of the emissions from the main and auxiliary engines. Please review the normal operation calculations for tug-boats for additional details.

Texas Gulf Terminals Inc.
Alternative Scenario Lightering Emissions Calculations
Criteria Pollutants

Annual VOC Emissions Estimates for Loading of Crude Oil and Condensate

											Complete Lightering [8]				
Liquid Loaded [1]	**Tankers**	**Percent Capacity Loaded**	**Saturation Factor [2]**	**Annual Average Temp [3] (°F)**	**(°R)**	**Vapor MW (lb/lb mol)**	**Average True Vapor Pressure (TVP) [4] (psia)**	**Uncontrolled Loading Loss [5] (lb/1,000 gal)**	**Capture Efficiency [9] (%)**	**Control Destruction Efficiency [9] (%)**	**Annual Loading Rate [6] [8] (bbl/yr)**	**Uncontrolled VOC Annual Emissions [7] (tpy)**	**Controlled VOC Annual Emissions (tpy)**	**Uncontrolled Fugitive Emissions (tpy)**	**Total VOC (tpy)**
Crude Oil	3 AFRAMAX	100%	0.2	73.50	533.17	50	11.00	2.57	99%	99%	192,000,000	10,364.91	102.61	103.65	206.26
Condensate	3 AFRAMAX	100%	0.2	73.50	533.17	62	9.25	2.68	99%	99%	192,000,000	10,807.77	107.00	108.08	215.07

											Partial Lightering [8]					
Liquid Loaded [1]	**Tankers**	**Percent Capacity Loaded**	**Saturation Factor [2]**	**Annual Average Temp [3] (°F)**	**(°R)**	**Vapor MW (lb/lb mol)**	**Average True Vapor Pressure (TVP) [4] (psia)**	**Uncontrolled Loading Loss [5] (lb/1,000 gal)**	**Capture Efficiency [9] (%)**	**Control Destruction Efficiency [9] (%)**	**Annual Loading Rate [6] [8] (bbl/yr)**	**Uncontrolled VOC Annual Emissions [7] (tpy)**	**Controlled VOC Annual Emissions (tpy)**	**Uncontrolled Fugitive Emissions (tpy)**	**Total VOC (tpy)**	**Reduction in VLCC Loading VOC Emissions [8] (tpy)**
Crude Oil	1 SUEZMAX	100%	0.2	73.50	533.17	50	11.00	2.57	99%	99%	96,000,000	5,182.46	51.31	51.82	103.13	
Condensate	1 SUEZMAX	100%	0.2	73.50	533.17	62	9.25	2.68	99%	99%	96,000,000	5,403.89	53.50	54.04	107.54	
Crude Oil	1 VLCC	50%	0.2	73.50	533.17	50	11.00	2.57	99%	99%	96,000,000	5,182.46	51.31	51.82	103.13	-5182.46
Condensate	1 VLCC	50%	0.2	73.50	533.17	62	9.25	2.68	99%	99%	96,000,000	5,403.89	53.50	54.04	107.54	-5403.89

Maximum reduction in VOC Loading Emissions in partial lightering relative to SPM loading in proposed design [8]	**-5403.89**

[1] For annual emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.
[2] Saturation factor for marine loading obtained from U.S. EPA AP-42, Section 5.2 (1/95), Table 5.2-1.
[3] Average of monthly average liquid temperature was used.
[4] Average true vapor pressure for Crude oil and Condensate obtained from information provided by Texas Gulf Terminals Inc. (TGTI).
[5] Uncontrolled Loading Loss (lb/1,000 gal) = 12.46 x Saturation Factor x Average TVP of Liquid Loaded (psia) x Vapor MW (lb/lbmol) / AverageTemperature of Bulk Liquid Loaded(R)

Crude Oil Uncontrolled Loading Loss (lb/1,000 gal) = (12.46 × 0.2 × 11.00 psia × 50 lb / lbmole) / (1 × 533.17 R) = 2.57 lb/1,000 gal

[6] Total Annual Loading Rate based on nine (8) 2-MMbbl VLCCs loaded per month.
[7] Uncontrolled VOC Loading Emissions (tpy) = Uncontrolled Loading Loss (lb/1,000 gal) x Annual Loading Rate (bbl/yr) x 42 gal/bbl x (1/1,000) x (1 ton/2,000 lb)

Crude Oil Uncontrolled Loading Emissions (tpy) = (2.57 lb / 1,000 gal) × (192,000,000 bbl / yr) × (42 gal / bbl) × (1 / 1,000) × (1 ton / 2,000 lb) = 10,365 tpy

[8] Capacities of various ships and tankers per http://allreltank.com/oil-tanker-ship/. Note that the shortest distance between the shore and SPM location is 15 miles but the distance travelled is not straight and estimated to be 65 miles one way.
Complete Lightering - Loading assumes that 3 AFRAMAX carriers load onshore, travel 65 miles and then unload to VLCC or
Partial Lightering - VLCCs come close to the shore and load to 50% capacity and then a SUEZMAX tanker travels and fills the remaining 50% of the VLCC offshore. For partial lightering it is assumed that Suezmax vessels also travel 65 miles.

Emissions reduced as the VLCC is filled out to 50% capacity close to the shore and uses controls. Emission Reduction = -50% x Max Uncontrolled VOC Loading Emissions from Normal Operation.

	Deadweight (tons)	*Capacity (bbls)*
AFRA Tankers	80,000	600,000
AFRAMAX	100,000	750,000
SUEZMAX	160,000	1,000,000

[9] Control efficiency as represented for other onshore terminals and also per current TCEQ policy. Capture efficiency was obtained from "Air Permits Division Marine Loading Collection Efficiency Guidance (September 21, 2016)" https://www.ilta.org/docs/marine-load-guide.pdf.

Annual NO_x, CO, and PM Emissions Estimates for Loading of Crude Oil and Condensate

Parameters	**Value**	**Unit**
NO_x Emission Factor [1]	0.10	lb/MMBtu
CO Emission Factor [1]	0.20	lb/MMBtu
$PM/PM_{10}/PM_{2.5}$ Emission Factor (Natural Gas)	7.60	lb/MMscf
$PM/PM_{10}/PM_{2.5}$ Emission Factor (Crude oil) [2]	17.57	lb/MMscf
$PM/PM_{10}/PM_{2.5}$ Emission Factor (Condensate) [2]	22.17	lb/MMscf
Molar Volume	389.18	ac/f/lbmole
Crude Oil Heat of Combustion [3]	18352	Btu/lb
Condensate Heat of Combustion [3]	18,679	Btu/lb

[1] NO_x and CO emission factors are assumed for conservation
[2] PM Emission Factor for Crude oil/Condensate = PM Emission Factor for Natural Gas Combustion (lb/MMscf) x (1/Natural Gas Heat of Combustion (Btu/scf)) x Crude oil/Condensate Heat of Combustion (Btu/lb) x Crude Oil/Condensate Vapor MW (lb/lbmole) x (1/Molar Volume (scf/lbmole@68.33°F))

PM Emission Factor for Condensate = (7.6 lb / MMscf) × (scf / 1,020 Btu) × (18,679 Btu / lb) × (62 lb / lbmole) × (lbmole / 389.18 scf) = 22.17 lb/MMscf

[3] Product Heat of Combustion based on representations in other permit applications.

				Complete Lightering				
Liquid Loaded [1]	**Annual Loading Rate [2] (bbl/yr)**	**Heat Input from Loading [3] MMBtu/yr**	**Annual Heat Input from Assist and Pilot Gas (MMBtu/yr)**	**Total Annual Heat Input (MMBtu/yr)**	**NO_x Annual Emissions [4] (tons/yr)**	**CO Annual Emissions [4] (tons/yr)**	**$PM/PM_{10}/PM_{2.5}$ Annual Emissions [5] (tons/yr)**
Crude Oil	192,000,000	376,629	376,629	753,259	37.66	75.33	2.82
Condensate	192,000,000	392,722	392,722	785,443	39.27	78.54	2.97

				Partial Lightering				
Liquid Loaded [1]	**Annual Loading Rate [2] (bbl/yr)**	**Heat Input from Loading [3] MMBtu/yr**	**Annual Heat Input from Assist and Pilot Gas (MMBtu/yr)**	**Total Annual Heat Input (MMBtu/yr)**	**NO_x Annual Emissions [4] (tons/yr)**	**CO Annual Emissions [4] (tons/yr)**	**$PM/PM_{10}/PM_{2.5}$ Annual Emissions [5] (tons/yr)**
Crude Oil	96,000,000	188,315	188,315	376,629	18.83	37.66	1.41
Condensate	96,000,000	196,361	196,361	392,722	19.64	39.27	1.48

[1] For hourly and annual emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.
[2] Annual Loading Rate obtained from information provided by TGTI Revised Design Parameters email from Ms. Denise Rogers (TGTI) to Mr. Brian Burdorf (Trinity Consultants) on February 25, 2018.
[3] Heat Input from Loading (MMBtu/yr) = Annual Loading Rate (bbl/yr) x Product Heat of Combustion (Btu/lb) x Uncontrolled Loading Loss (lb/1,000 gal) x Capture Efficiency (%) x 42 gal/bbl x (1/1,000) x (1/1,000,000)

Condensate Heat Input from Loading (MMBtu/yr) = (192,000,000 bbl / yr) × (18,679 Btu / lb) × (2.68 lb / 1,000 gal) × (99.00%) × (42 gal / bbl) × (1 MMBtu / 1000000 Btu) = 392,722 MMBtu/yr

[4] NO_x and CO, Annual Emissions (tpy) = Heat Input Rate from Loading (MMBtu/yr) x Emission Factor (lb/MMBtu) x (1 ton/2,000 lb)

Condensate NO_x Annual Emissions (tpy) = (392,722 MMBtu / yr) × (0.1 lb / MMBtu) × (1 ton / 2,000 lb) = 39.27 tpy

[5] PM Annual Emissions (tpy) = Annual Loading Rate (bbl/yr) x Uncontrolled Loading Loss (lb/1,000 gal) x 42 gal/bbl x (1/Vapor MW (lb/lbmole)) x Molar Volume (scf/lbmole@68.33 F) x Emission Factor (lb/MMscf) x (1/1,000) x (1/1,000,000) x (1 ton/2,000 lb)

Condensate PM Annual Emissions (tpy) = (192,000,000 bbl / yr) × (2.68 lb / 1,000 gal) × (42 gal / bbl) × (lbmole / 62 lb) × (389.18 scf / lbmole) × (22.17 lb / MMscf) × (1 MMscf / 1000000 scf) × (1 / 1,000) × (1 ton / 2,000 lb) = 2.97 tpy

[6] Assumes a 1:1 overall ratio of assist and pilot gas heat input for operation of the VCU

Annual H_2S and SO_2 Emissions Estimates for Loading of Crude Oil and Condensate

			Complete Lightering			
Liquid Loaded [1]	**H_2S Vapor Fraction [2]**	**Average TVP [3] (psia)**	**Mass Ratio of H_2S [4] lb H_2S/lb VOC**	**VOC Annual Emissions (tpy)**	**H_2S Annual Emissions [5] (tpy)**	**SO_2 Annual Emissions [4] (tpy)**
Crude Oil	2.40E-05	11.00	2.19E-05	206	0.00	0.85
Condensate	2.40E-05	9.25	2.10E-05	215	0.00	0.85

			Partial Lightering			
Liquid Loaded [1]	**H_2S Vapor Fraction [2]**	**Average TVP [3] (psia)**	**Mass Ratio of H_2S [4] lb H_2S/lb VOC**	**VOC Annual Emissions (tpy)**	**H_2S Annual Emissions [5] (tpy)**	**SO_2 Annual Emissions [4] (tpy)**
Crude Oil	2.40E-05	11.00	2.19E-05	103	0.00	0.42
Condensate	2.40E-05	9.25	2.10E-05	108	0.00	0.42

[1] For hourly and annual emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.
[2] Maximum H_2S vapor fraction is assumed to be 24 ppmv for sweet crude.
[3] True vapor pressure for Crude oil and Condensate obtained from information provided by TGTI.

[4] H_2S Mass Ratio in Crude Oil/Condensate (lb H_2S/lb VOC) = H_2S Vapor Fraction in Crude Oil/Condensate x H_2S MW (lb/lbmole)/Crude Oil/Condensate Vapor MW (lb/lbmole) x 14.7 psia/Vapor Pressure of Crude Oil/Condensate (psia)

H_2S Mass Ratio in Crude Oil (lb H_2S/lb VOC) = (2.40E-05 / lbmole) × (34.1 lb / lbmole) × (lbmole / 50 lb) × (14.7 psia / 11 psia) = 2.19E-05 lb H2S/lb VOC

[5] H_2S Annual Emissions (tpy) = Max H_2S Mass Ratio in Crude/Condensate (lb H_2S/lb VOC) x Uncontrolled VOC Annual Emissions (tpy)

H_2S Annual Emissions from Crude Oil (tpy) = (2.19E-05 lb H2S / lb VOC) × (206 tpy) = 0.00 tpy

Hourly and Annual GHG Emissions Estimates for Loading of Products

Emission Factor	**Value**	**Unit**
CO_2 Emission Factor [1]	74.54	kg/MMBtu
CH_4 Emission Factor [1]	0.0030	kg/MMBtu
N_2O Emission Factor [1]	0.0006	kg/MMBtu
CO_2 Global Warming Potential [2]	1	
CH_4 Global Warming Potential [2]	25	
N_2O Global Warming Potential [2]	298	

[1] Emission factors are from 40 CFR Part 98, Subpart C, Tables C-1 and C-2 for Crude Oil.
[2] Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1.

Loading Vessel	**Liquid Loaded (bbl/yr)**	**Annual Heat Input from Vapors (MMBtu/yr)**	**Annual Heat Input from Assist and Pilot Gas [3] (MMBtu/yr)**	**Total Annual Heat Input (MMBtu/yr)**	**CO_2 Annual Emissions [1] (tpy)**	**CH_4 Annual Emissions [1] (tpy)**	**N_2O Annual Emissions [1] (tpy)**	**CO_2e Annual Emissions [2] (tpy)**
Complete Lightering								
Crude Oil	192,000,000	376,629	376,629	753,259	61,892	2.49	0.50	62,103
Condensate	192,000,000	392,722	392,722	785,443	64,537	2.60	0.52	64,757
Partial Lightering								
Crude Oil	96,000,000	188,315	188,315	376,629	30,946	1.25	0.25	31,052
Condensate	96,000,000	196,361	196,361	392,722	32,268	1.30	0.26	32,378

[1] CO_2, N_2O and CH_4 Annual Emissions (tpy) = Emission Factor (kg/MMBtu) x Heat Input from Loading (MMBtu/yr) x (1 ton/2,000 lb) x (2.20462 lb/1 kg)

CO_2 Annual Emissions from Ship/OGB Loading (tpy) = (74.54 lb / MMBtu) × (376,629 MMBtu / yr) × (1 ton / 2,000 lb) × (2.20462 lb / 1 kg) = 61,892 tpy

[2] CO_2e emissions are calculated based on the Global Warming Potentials (GWP)
$CO_2e = CO_2$ Emission Rate * CO_2 GWP + CH_4 Emission Rate * CH_4 GWP + N_2O Emission Rate * N_2O GWP
[3] Assumes a 1:1 overall ratio of assist and pilot gas heat input for operation of the VCU

Texas Gulf Terminals Inc.
Alternative Scenario Lightering Emissions Calculations

Hazardous Air Pollutants

Parameters	Value	Unit
Max. benzene vapor weight % in Crude Oil [1]	0.95%	
Max. benzene vapor weight % in Condensate [1]	0.43%	
Max toluene Vapor weight % in Crude Oil [1]	0.98%	
Max toluene Vapor weight % in Condensate [1]	0.37%	

[1] The liquid composition of crude oil/condensate is obtained from crude profiles data provided by Ms. Denise Rogers (TGTI) in an email to Trinity Consultants on 9/11/2017. The liquid composition is used as an input in tanks 4.09d run to obtain the vapor composition of crude oil/condensate.

Complete Lightering

3 AFRAMAX carriers load onshore, travel 65 miles and then unload to VLCC

Pollutant	Liquid Loaded [1]	Total VOC Annual Emissions [3] (tpy)	Annual Emissions [2] (tpy)
Benzene	Crude Oil	206	1.96
	Condensate	215	0.92
Toluene	Crude Oil	206	2.02
	Condensate	215	0.80

Partial Lightering

Suezmax vessel is loaded to 100% capacity and travels and fills the remaining 50% of the VLCC. It is assumed that Suezmax vessel also travels 65 miles.

Pollutant	Liquid Loaded [1]	Total VOC Annual Emissions [3] (tpy)	Annual Emissions [2] (tpy)
Benzene	Crude Oil	103	0.98
	Condensate	108	0.46
Toluene	Crude Oil	103	1.01
	Condensate	108	0.40

[1] For hourly and annual emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.
[2] Benzene Annual Emissions (tpy) = Max Benzene % in Crude/Condensate Vapors x Uncontrolled VOC Annual Emissions (tpy)
[3] Emissions are based on the total VOC emissions for Loading of Crude Oil and Condensate calculated in the previous table.

$$\text{Benzene Annual Emissions from Crude Oil (tpy)} = \frac{0.95\%}{} \left| \frac{206 \text{ tons}}{\text{yr}} \right. = 1.96 \text{ tpy}$$

Toluene Annual Emissions (tpy) = Max Toluene % in Crude/Condensate Vapors x Uncontrolled VOC Annual Emissions (tpy)

$$\text{Toluene Annual Emissions from Crude Oil (tpy)} = \frac{0.98\%}{} \left| \frac{206 \text{ tons}}{\text{yr}} \right. = 2.02 \text{ tpy}$$

Texas Gulf Terminals Inc.
Alternative Scenario Transit Emission Calculations
Marine Product Transit
Criteria Pollutants

Annual VOC Emissions Estimates for Transit of Crude Oil and Condensate (Complete Lightering)

3 AFRAMAX carriers load onshore, travel 65 miles and then unload to VLCC

Product in Transit [1]	Condensed Vapor Density (lb/gal)	Average True Vapor Pressure (TVP) [2] (psia)	Uncontrolled Transit Loss [3] (lb/1,000 gal-day)	No. of days for Transit [4] [6] (days)	Control Destruction Efficiency (%)	Annual Transit Rate [4] (bbl/yr)	Controlled VOC Annual Emissions [5] (tpy)
Crude Oil	7.1	11.00	1.12	0.60	0%	192,000,000	2,718
Condensate	5.6	9.25	0.74	0.60	0%	192,000,000	1,803

Annual VOC Emissions Estimates for Transit of Crude Oil and Condensate (Partial Lightering)

VLCCs come close to the shore and load to 50% capacity and then one Suezmax vessel is loaded to 100% capacity and travels and fills the remaining 50% of the VLCC. It is assumed that Suezmax vessel also travels 65 miles.

Product in Transit [1]	Condensed Vapor Density (lb/gal)	Average True Vapor Pressure (TVP) [2] (psia)	Uncontrolled Transit Loss [3] (lb/1,000 gal-day)	No. of days for Transit [4] [6] (days)	Control Destruction Efficiency (%)	Annual Transit Rate [4] (bbl/yr)	Controlled VOC Annual Emissions [5] (tpy)
Crude Oil	7.1	11.00	1.12	0.60	0%	192,000,000	2,718
Condensate	5.6	9.25	0.74	0.60	0%	192,000,000	1,803

[1] For annual emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.

[2] Vapor pressures are retained consistent with those used for the Tank Farm.

[3] Uncontrolled loading loss during transfer operations is calculated using equation 5 from U.S. EPA 42, Section 5.2 (6/08).

[4] Note that the shortest distance between the shore and SPM location is 15 miles but the distance travelled is not straight and estimated to be 65 miles one way. Transit time is conservatively estimated at 14.5 hrs or 0.60 days one way.

[5] Controlled VOC Loading Emissions (tpy) = Uncontrolled Loading Loss (lb/1,000 gal) x Annual Loading Rate (bbl/yr) x 42 gal/bbl x (1/1,000) x (1 ton/2,000 lb) x (1- Control Efficiency (%))

[6] Capacities of various ships and tankers per http://alloiltank.com/oil-tanker-ship/

Loading assumes that 3 AFRAMAX carriers load onshore, travel 65 miles and then unload to VLCC or VLCCs come close to the shore and load to 50% capacity and then 1 Suezmax vessel travels and fill the remaining 50% of the VLCC. It is assumed that Suezmax vessel and VLCC travel 65 miles one way.

	Capacity (bbls)
AFRAMAX	750,000
SUEZMAX	1,000,000
VLCC	2,000,000

$$\text{Crude Oil Transfer Emissions (tpy)} = \frac{1.12\text{ lb}}{1{,}000\text{ gal-day}} \cdot \frac{0.6\text{ day}}{} \cdot \frac{192{,}000{,}000\text{ bbl}}{\text{yr}} \cdot \frac{42\text{ gal}}{\text{bbl}} \cdot \frac{1}{1{,}000} \cdot \frac{1\text{ ton}}{2{,}000\text{ lb}} = 2{,}718\text{ tpy}$$

Annual H_2S Emissions Estimates for Transfer of Crude Oil and Condensate

Liquid Loaded [1]	H_2S Vapor Fraction [2]	Average TVP [3] (psia)	Mass Ratio of H_2S [4] lb H_2S/lb VOC	Complete Lightering VOC Annual Emissions (tpy)	Complete Lightering H_2S Annual Emissions [5] (tpy)	Partial Lightering VOC Annual Emissions (tpy)	Partial Lightering H_2S Annual Emissions [5] (tpy)
Crude Oil	2.40E-05	11.00	2.19E-05	2,718	0.06	2,718	0.06
Condensate	2.40E-05	9.25	2.10E-05	1,803	0.04	1,803	0.04

[1] For hourly and annual emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.

[2] Maximum H_2S vapor fraction is assumed to be 24 ppmv for sweet crude.

[3] Vapor pressures are retained consistent with those used for the Tank Farm.

[4] H_2S Mass Ratio in Crude Oil/Condensate (lb H_2S/lb VOC) = H_2S Vapor Fraction in Crude Oil/Condensate x H_2S MW (lb/lbmole)/Crude Oil/Condensate Vapor MW (lb/lbmole) x 14.7 psia/Vapor Pressure of Crude Oil/Condensate (psia)

$$H_2S\text{ Mass Ratio in Crude Oil (lb } H_2S\text{/lb VOC)} = \frac{2.40\text{E-05}}{} \cdot \frac{34.1\text{ lb}}{\text{lbmole}} \cdot \frac{\text{lbmole}}{50} \cdot \frac{14.7\text{ psia}}{11\text{ psia}} = 2.19\text{E-05 lb H2S/lb VOC}$$

[5] H_2S Annual Emissions (tpy) = Max H_2S Mass Ratio in Crude/Condensate (lb H_2S/lb VOC) x Uncontrolled VOC Annual Emissions (tpy)

$$H_2S\text{ Annual Emissions from Crude Oil (tpy)} = \frac{2.19\text{E-05 lb H2S}}{\text{lb VOC}} \cdot \frac{2{,}718\text{ tpy}}{} = 0.06\text{ tpy}$$

Texas Gulf Terminals Inc.
Alternative Scenario Transit Emission Calculations
Marine Product Transit
Hazardous Air Pollutants

Parameters	Value	Unit
Max. benzene vapor weight % in Crude Oil [1]	0.95%	
Max. benzene vapor weight % in Condensate [1]	0.43%	
Max toluene Vapor weight % in Crude Oil [1]	0.98%	
Max toluene Vapor weight % in Condensate [1]	0.37%	

[1] The liquid composition of crude oil/condensate is obtained from crude profiles data provided by Ms. Denise Rogers (TGTI) in an email to Trinity Consultants on 9/11/2017. The liquid composition is used as an input in tanks 4.09d run to obtain the vapor composition of crude oil/condensate.

Complete Lightering

3 AFRAMAX carriers load onshore, travel 65 miles and then unload to VLCC

Pollutant	Liquid Loaded [1]	Uncontrolled VOC Annual Emissions (tpy)	Annual Emissions [2] (tpy)
Benzene	Crude Oil	2,718	25.82
	Condensate	1,803	7.75
Toluene	Crude Oil	2,718	26.64
	Condensate	1,803	6.67

Partial Lightering

VLCCs come close to the shore and load to 50% capacity and then one Suezmax vessel is loaded to 100% capacity and travels and fills the remaining 50% of the VLCC. It is assumed that Suezmax vessel also travels 65 miles.

Pollutant	Liquid Loaded [1]	Uncontrolled VOC Annual Emissions (tpy)	Annual Emissions [2] (tpy)
Benzene	Crude Oil	2,718	25.82
	Condensate	1,803	7.75
Toluene	Crude Oil	2,718	26.64
	Condensate	1,803	6.67

[1] For hourly and annual emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.
[2] Benzene Annual Emissions (tpy) = Max Benzene % in Crude/Condensate Vapors x Uncontrolled VOC Annual Emissions (tpy)
[3] Emissions are based on the total VOC emissions for transfer of Crude Oil and Condensate calculated in the previous table.

$$\text{Benzene Annual Emissions from Crude Oil (tpy)} = \frac{0.95\% \mid 2{,}718 \text{ tons}}{\text{yr}} = 25.82 \text{ tpy}$$

Toluene Annual Emissions (tpy) = Max Toluene % in Crude/Condensate Vapors x Uncontrolled VOC Annual Emissions (tpy)

$$\text{Toluene Annual Emissions from Crude Oil (tpy)} = \frac{0.98\% \mid 2{,}718 \text{ tons}}{\text{yr}} = 26.64 \text{ tpy}$$

Texas Gulf Terminals Inc.
Alternative Scenario Support Tanker Propulsion Emission Calculations

Criteria Pollutants

		Complete Lightering		Partial Lightering	
Engine Rating [1], [4]	=	11,003	kW	14,670	kW
		14,754	HP	19,672	HP
Total Travel time [2]		435.0	days	145.00	days
Operating Time [2]	=	24.0	hrs/day	24.0	hrs/day
		10,440	hrs/yr	3,480	hrs/yr
Operating load [2]	=	57%		57%	
Fuel Type [3]	=	Diesel		Diesel	

					Complete Lightering			Partial Lightering		
Pollutant	Emission Factor Basis		Emission Factor		Maximum Emissions	Maximum Daily Emissions	Annual Emissions	Maximum Emissions	Maximum Daily Emissions	Annual Emissions
			Value	Units	(lb/hr)	(lb/day)	(tons/yr)	(lb/hr)	(lb/day)	(tons/yr)
PM	BOEM 2014-666	[4]	7.40E-01	g/kW-hr	10.23	245.55	53.41	13.64	327.40	23.74
PM_{10}	BOEM 2014-666	[4]	7.40E-01	g/kW-hr	10.23	245.55	53.41	13.64	327.40	23.74
$PM_{2.5}$	BOEM 2014-666	[4]	6.80E-01	g/kW-hr	9.40	225.64	49.08	12.54	300.86	21.81
NO_x	BOEM 2014-666	[4]	1.95E+01	g/kW-hr	270.16	6483.93	1410.26	360.22	8645.24	626.78
SO_2	Fuel S Content	[3]	7.48E-04	lb/HP-hr	6.29E+00	1.51E+02	32.83	8.38	201.23	14.59
CO	BOEM 2014-666	[4]	1.77E+00	g/kW-hr	24.47	587.34	127.75	32.63	783.12	56.78
VOC	AP-42 Chapter 3	[5]	6.42E-04	lb/HP-hr	5.40	129.49	28.16	7.19	172.65	12.52
Pb	EPA	[6]	2.03E-07	lb/HP-hr	1.71E-03	4.10E-02	8.91E-03	2.28E-03	5.46E-02	3.96E-03
H_2SO_4	Fuel S Content	[3]	2.34E-05	lb/HP-hr	1.96E-01	4.71E+00	1.03E+00	2.62E-01	6.29E+00	4.56E-01

[1] Representative engine specifications used from Apolytares Q88 vessel. HP adjusted for volume of the tankers as engine data not available.

[2] Operating time assumed to be the same as the travel time (14.5 hrs one way). A factor of 50% is added in for time spent during loading/unloading when the engine is running on one side of the trip.

Complete Lightering - It takes 14.5 hours for each AFROMAX tanker to travel to the VLCC and 3 AFROMAX tankers are needed to load one VLCC.

Partial Lightering - It takes 14.5 hours for each SUEZMAX tanker to travel to the VLCC and 1 SUEZMAX tanker is needed to load half VLCC.

Operating load is estimated based on the following calculation - (25% x 7 hrs + 90% x 14.5 hrs + 40% x 14.5 hrs)/(36) where 25% of the operated load happens during loading/unloading operations, 90% of the load when the carrier is travelling and full with crude and 40% when its making a trip back and is empty.

[3] Sulfur content of 0.1% is used per IMO standards for 2015. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO2 and 2 percent of sulfur in the fuel is oxidized to H2SO4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

[4] Crude Carrier emission factors from Table 6-1 Year 2011 Gulfwide Emission Inventory Study (BOEM 2014-666) for Commercial Marine Vessels for Diesel. No HAPs emission factors reported.

[5] Emission factors are based on AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996).

[6] Lead emission factor was obtained from EPA guidance document: Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA 454/R-98-006, May 1998, Section 5.2.2. Emission factor for distillate oil-fired gas turbines was used as a surrogate for distillate oil-fired engines due to lack of emission factors.

Sample Calculations:

Max LB/HR Emissions (PM) = 0.74 g/kW-hr x 11002.5 KW / 453.59 g/lb x 57% = 10.2314 lb/hr
Max Daily Emissions (PM) = 10.2314 lb/hr x 24 hrs/day= 245.5533 lb/day
Annual Emissions (PM) = 10.2314 lb/hr x 10440 hrs/yr / 2000 lb/ton= 53.4078 tpy

Texas Gulf Terminals Inc.
Alternative Scenario Support Tanker Propulsion Emission Calculations

Greenhouse Gases

		Complete Lightering		Partial Lightering	
Engine Rating [1]	=	11,003	kW	14,670	kW
		14,754	HP	19,672	HP
Operating Time [2]	=	24	hrs/day	24	hrs/day
		10,440	hrs/yr	3,480	hrs/yr
Fuel Type [7]	=	Diesel		Diesel	
Engine Speed [1]	=	1,000	rpm	1,000	rpm
Operating load [2]	=	57%		57%	

Pollutant	Emission Factor Basis		Emission Factor		Complete Lightering			Partial Lightering		
			Value	Units	Average Emissions [5] (lb/hr)	Average Daily Emissions (lb/day)	Annual Emissions (tons/yr)	Average Emissions [5] (lb/hr)	Average Daily Emissions (lb/day)	Annual Emissions (tons/yr)
CO_2	40 CFR 98 Subpart C	[3]	7.40E+01	kg/MMBtu	9,599	230,375	50,107	12,799	307,166	22,270
CH_4	40 CFR 98 Subpart C	[4]	3.00E-03	kg/MMBtu	0.39	9.34	2.03	0.52	12.46	0.90
N_2O	40 CFR 98 Subpart C	[4]	6.00E-04	kg/MMBtu	0.08	1.87	0.41	0.10	2.49	0.18
CO_2e	40 CFR 98 Subpart C	[6]	--	--	**9,632**	**231,165**	**50,278**	**12,843**	**308,220**	**22,346**

[1] Representative engine specifications used from Apolytares Q88 vessel. HP adjusted for volume of the tankers as engine data not available.

[2] Operating time assumed to be the same as the travel time (14.5 hrs one way). A factor of 50% is added in for time spent during loading/unloading when the engine is running on one side of the trip.
Complete Lightering - It takes 14.5 hours for each AFROMAX tanker to travel to the VLCC and 3 AFROMAX tankers are needed to load one VLCC.
Partial Lightering - It takes 14.5 hours for each SUEZMAX tanker to travel to the VLCC and 1 SUEZMAX tanker is needed to load half VLCC.

[3] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[4] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[5] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

[6] CH_4, CO_2 and N_2O are included in the emissions of CO_2 equivalent (CO_2e), weighted according to their global warming potential (GWP). The GWP was obtained from table A-1 to Subpart A of Part 98. This is consistent with TCEQ 2015 guidance:
https://www.tceq.texas.gov/assets/public/permitting/air/factsheets/factsheets-psdghg-6291.pdf
CH4 = 25, N2O = 298.

[7] Sulfur content of 1000 ppm has been used per IMO standards for 2015. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO2 and 2 percent of sulfur in the fuel is oxidized to H2SO4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

Sample Calculations:

Max LB/HR Emissions (CO2) = 73.96 kg/MMBtu x 2.20462 Lb/Kg /1000000 x 7000 Btu/hp-hr x 14754.3525 HP x 57% = 9599 lb/hr
Max Daily Emissions (CO2) = 9599 lb/hr x 24 hrs/day= 230374.7824 lb/day
Annual Emissions (CO2) = 9599 lb/hr x 10440 hrs/yr / 2000 lb/ton= 50107 tpy
CO2e (tpy) = 50107 tpy CO2 x 1 + 2.03 tpy CH4 x 25 + 0.406 tpy N2O x 298 = 50278 tpy

Texas Gulf Terminals Inc.
Alternative Scenario Support Tanker Propulsion Emission Calculations

Hazardous Air Pollutants

		Complete Lightering		Partial Lightering	
Engine Rating [1]	=	11,003	kW	14,670	kW
		14,754	HP	19,672	HP
Operating Time [2]	=	24.0	hrs/day	145.00	hrs/day
		10,440	hrs/yr	3,480	hrs/yr
Fuel Type [6]	=	Diesel		Diesel	
Engine Speed [1]	=	1,000	rpm	1,000	rpm
Operating load [2]	=	57%		57%	

Pollutant	Emission Factor Basis		Emission Factor		Complete Lightering			Partial Lightering		
			Value	Units	Maximum Emissions (lb/hr)	Maximum Daily Emissions (lb/day)	Annual Emissions (tons/yr)	Maximum Emissions (lb/hr)	Maximum Daily Emissions (lb/day)	Annual Emissions (tons/yr)
Acetaldehyde	AP-42	[3],[5]	2.52E-05	lb/MMBtu	1.48E-03	3.56E-02	7.74E-03	1.98E-03	2.87E-01	3.44E-03
Acrolein	AP-42	[3],[5]	7.88E-06	lb/MMBtu	4.64E-04	1.11E-02	2.42E-03	6.19E-04	8.97E-02	1.08E-03
Benzene	AP-42	[3],[5]	7.76E-04	lb/MMBtu	4.57E-02	1.10E+00	2.38E-01	6.09E-02	8.83E+00	1.06E-01
Formaldehyde	AP-42	[3],[5]	7.89E-05	lb/MMBtu	4.64E-03	1.11E-01	2.42E-02	6.19E-03	8.98E-01	1.08E-02
Toluene	AP-42	[3],[5]	2.81E-04	lb/MMBtu	1.65E-02	3.97E-01	8.64E-02	2.21E-02	3.20E+00	3.84E-02
Xylenes	AP-42	[3],[5]	1.93E-04	lb/MMBtu	1.14E-02	2.73E-01	5.93E-02	1.51E-02	2.20E+00	2.64E-02
Total PAH	AP-42	[4],[5]	2.12E-04	lb/MMBtu	1.25E-02	3.00E-01	6.51E-02	1.66E-02	2.41E+00	2.90E-02
Naphthalene	AP-42	[4],[5]	1.30E-04	lb/MMBtu	7.65E-03	1.84E-01	3.99E-02	1.02E-02	1.48E+00	1.78E-02
Total VOC HAPs					**1.00E-01**	**2.41E+00**	**5.24E-01**	**1.34E-01**	**1.94E+01**	**2.33E-01**

[1] Representative engine specifications used from Apolytares Q88 vessel. HP adjusted for volume of the tankers as engine data not available.

[2] Operating time assumed to be the same as the travel time (14.5 hrs one way). A factor of 50% is added in for time spent during loading/unloading when the engine is running on one side of the trip.
Complete Lightering - It takes 14.5 hours for each AFROMAX tanker to travel to the VLCC and 3 AFROMAX tankers are needed to load one VLCC.
Partial Lightering - It takes 14.5 hours for each SUEZMAX tanker to travel to the VLCC and 1 SUEZMAX tanker is needed to load half VLCC.
Operating load is estimated based on the following calculation - (25% x 7 hrs + 90% x 14.5 hrs + 40% x 14.5 hrs)/(36) where 25% of the operated load happens during loading/unloading operations, 90% of the load when the carrier is travelling and full with crude and 40% when its making a trip back and is empty.

[3] Emission factors based on AP-42, Chapter 3, Table 3.4-3, Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[4] Emission factors based on AP-42, Chapter 3, Table 3.4-4, PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[5] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

[6] Sulfur content of 0.1% is used per IMO standards for 2015. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO2 and 2 percent of sulfur in the fuel is oxidized to H2SO4 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

Sample Calculations:

Max LB/HR Emissions (Acetaldehyde) = 0.00003 lb/MMBtu x 7000 Btu/Hp-hr / 1000000 x 14754.3525 HP x 57% = 0.0015 lb/hr
Max Daily Emissions (Acetaldehyde) = 0.0015 lb/hr x 24 hrs/day= 0.0356 lb/day
Annual Emissions (Acetaldehyde) = 0.0015 lb/hr x 10440 hrs/yr / 2000 lb/ton= 0.0077 tpy

New Source Review Air Permit Application

Texas Gulf Terminals Inc.
Texas Gulf Terminals Project

Appendix B

Prepared By:

TRINITY CONSULTANTS
555 N Carancahua St.
Suite 820
Corpus Christi, Texas 78401
(361)-883-1668

July 2018

Environmental solutions delivered uncommonly well

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1. EXECUTIVE SUMMARY

1.1. PROJECT BACKGROUND

Texas Gulf Terminals Inc. (TGTI) is proposing to construct, own, and operate a Deepwater Port (DWP), as part of the Texas Gulf Terminal Project, in Federal waters of the U.S. Gulf of Mexico located approximately 14 miles off the coast of North Padre Island in Kleberg County, Texas.

The purpose of the proposed project is to provide a safe, efficient and cost effective logistical solution for the export of crude oil from the United States of America (U.S.) to support the continued economic growth of the U.S.

The DWP terminal will include a Single Point Mooring (SPM) buoy system to moor a Very Large Crude Carrier (VLCC). The size of these VLCCs and inland port draft limitations prevent them from using the traditional docks at onshore terminals. Therefore, VLCCs have to be engaged offshore. The proposed SPM buoy system will be located in water with over 90 feet of depth, allowing a VLCC to be fully and directly loaded without the use of lightering (i.e., using smaller ships to transport crude oil from on-shore terminals out to VLCCs located in deeper waters).

The project will serve as a crude oil export facility with a capacity of 60,000 barrels per hour (bph) and 192 million barrels per year. The project will be able to load up to approximately 96 VLCCs per year. The proposed project is comprised of two major offshore components: the SPM Buoy system and the offshore pipelines. A detailed description of the SPM Buoy system components and the offshore pipeline system is provided in Section 4.

Per 33 CFR §148.3(d), The Environmental Protection Agency (EPA) is designated as cooperating agency to support the Coast Guard and MARAD in the review and evaluation of DWP license applications. Since the proposed project results in emissions of regulated pollutants, TGTI is submitting this permit application as part of the DWP license application to MARAD/USCG. TGIT has prepared the application on Texas Commission on Environmental Quality (TCEQ) forms based on guidance received from EPA Region 6. With this submittal, TGTI is proposing to authorize the Volatile Organic Compounds (VOC) and HAP emissions resulting from the loading of crude oil from the DWP Terminal onto a VLCC. Based on potential air emissions from the facility, the project will be subject to preconstruction review under the federal Prevention of Significant Deterioration (PSD) regulations since potential emissions of VOC will be greater than the 250 ton per year PSD major source threshold. A deepwater port is defined in 33 CFR 148.5 as follows:

> *Any fixed or floating manmade structures other than a vessel, or any group of structures, located beyond State seaward boundaries that are used or are intended for use as a port or terminal for the transportation, storage, or further handling of oil or natural gas for transportation to any State, except as otherwise provided in the Deepwater Ports Act of 1974, as amended, and for other uses not inconsistent with the purposes of the Deepwater Port Act, including transportation of oil and natural gas from the United States' OC; […] Must be considered a 'new source' for purposes of the Clean Air Act.."*

In addition to the loading operations, other ancillary sources such as engines and cranes located on the VLCC; and support vessels such as tug boats also result in emissions. As mentioned above, the DWP consists of the SPM buoy system that is used for loading of crude carrier vessels. Per the 1974 DWPA, the revised 2012 DWPA, and the DWP regulations (40 CFR 148.5), a DWP new source for purposes of the Clean Air Act is defined as "any fixed or floating manmade structure other than a vessel, or any group of such structures, that are located beyond State seaward boundaries and that are used or intended for use as a port or terminal for the transportation, storage, or further handling of oil or natural gas for transportation to or from any State…". Therefore, vessels are not

considered primary/direct sources of emissions from the Project for Clean Air Act new source review regulatory applicability. Per 40 CFR 52.21 emissions from the ancillary sources are secondary emissions and are not required to be included in comparison with the PSD major source thresholds. The secondary emissions are included in the source impact analysis submitted under separate cover. The proposed deepwater port source only triggers PSD permitting for VOC. The Federal New Source Review (FNSR) applicability is discussed in detail in Section 6.

Supporting documentation for this application is provided in the following sections. Included in Section 2 of this permit application is the required applicant information (including TCEQ Form PI-1 and Table 1(a)). The project location is discussed in Section 3, with an area map indicating the site locations. The process and project descriptions are provided in Section 4, including a process flow diagram and plot plan. Emission calculations are discussed in Section 5. FNSR applicability is covered in Section 6. The summary of Federal Best Available Control Technology (BACT) is provided in Section 7. The PSD air quality modeling and additional impacts analysis are addressed in Section 8. A review of general application requirements, including a federal and state regulatory applicability review, is provided in Section 9. Lastly, the permit fee and PE certification are addressed in Section 10.[1] All supporting calculations and data are included in the Appendices.

[1] Per guidance from EPA Region 6, there is no permit fee associated with a PSD permit application. TGTI has included the permit fee form in Section 10 to document no permit fee required.

2. APPLICANT INFORMATION: TCEQ FORMS

CORE DATA FORM

PI-1 FORM

TABLE 1(a)

TCEQ Core Data Form

TCEQ Use Only

For detailed instructions regarding completion of this form, please read the Core Data Form Instructions or call 512-239-5175.

SECTION I: General Information

1. Reason for Submission (If other is checked please describe in space provided.)

☒ New Permit, Registration or Authorization (Core Data Form should be submitted with the program application.)

☐ Renewal (Core Data Form should be submitted with the renewal form) ☐ Other

2. Customer Reference Number (if issued)		3. Regulated Entity Reference Number (if issued)
CN 605490085	Follow this link to search for CN or RN numbers in Central Registry**	RN

SECTION II: Customer Information

4. General Customer Information 5. Effective Date for Customer Information Updates (mm/dd/yyyy)

☐ New Customer ☐ Update to Customer Information ☐ Change in Regulated Entity Ownership
☐ Change in Legal Name (Verifiable with the Texas Secretary of State or Texas Comptroller of Public Accounts)

The Customer Name submitted here may be updated automatically based on what is current and active with the Texas Secretary of State (SOS) or Texas Comptroller of Public Accounts (CPA).

6. Customer Legal Name (If an individual, print last name first: e.g.: Doe, John) — If new Customer, enter previous Customer below:

Texas Gulf Terminals Inc.

7. TX SOS/CPA Filing Number	8. TX State Tax ID (11 digits)	9. Federal Tax ID (9 digits)	10. DUNS Number (if applicable)
0802978324	32066715692		

11. Type of Customer: ☒ Corporation ☐ Individual Partnership: ☐ General ☐ Limited
Government: ☐ City ☐ County ☐ Federal ☐ State ☐ Other ☐ Sole Proprietorship ☐ Other:

12. Number of Employees
☒ 0-20 ☐ 21-100 ☐ 101-250 ☐ 251-500 ☐ 501 and higher

13. Independently Owned and Operated?
☒ Yes ☐ No

14. Customer Role (Proposed or Actual) - as it relates to the Regulated Entity listed on this form. Please check one of the following:

☐ Owner ☐ Operator ☒ Owner & Operator
☐ Occupational Licensee ☐ Responsible Party ☐ Voluntary Cleanup Applicant ☐ Other:

15. Mailing Address:
1401 McKinney
Suite 1500

City	Houston	State	TX	ZIP	77010	ZIP + 4	

16. Country Mailing Information (if outside USA) 17. E-Mail Address (if applicable)

18. Telephone Number	19. Extension or Code	20. Fax Number (if applicable)
(832) 203 - 6400		( ) -

SECTION III: Regulated Entity Information

21. General Regulated Entity Information (If `New Regulated Entity" is selected below this form should be accompanied by a permit application)

☒ New Regulated Entity ☐ Update to Regulated Entity Name ☐ Update to Regulated Entity Information

The Regulated Entity Name submitted may be updated in order to meet TCEQ Agency Data Standards (removal of organizational endings such as Inc, LP, or LLC).

22. Regulated Entity Name (Enter name of the site where the regulated action is taking place.)

Texas Gulf Terminals Project

23. Street Address of the Regulated Entity: (No PO Boxes)							
	City		State		ZIP		ZIP + 4
24. County							

Enter Physical Location Description if no street address is provided.

25. Description to Physical Location:	Site is approximately 14 miles offshore the coast of Texas, Southeast of Corpus Christi.		
26. Nearest City		State	Nearest ZIP Code
N/A		TX	N/A

27. Latitude (N) In Decimal:	27.4785		28. Longitude (W) In Decimal:	97.013453	
Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
27	28	42.6	97	00	48.43

29. Primary SIC Code (4 digits)	30. Secondary SIC Code (4 digits)	31. Primary NAICS Code (5 or 6 digits)	32. Secondary NAICS Code (5 or 6 digits)
4612		486910	

33. What is the Primary Business of this entity? (Do not repeat the SIC or NAICS description.)

Offshore Marine Terminal

34. Mailing Address:	1401 McKinney						
	Suite 1500						
	City	Houston	State	TX	ZIP	77010	ZIP + 4
35. E-Mail Address:							

36. Telephone Number	37. Extension or Code	38. Fax Number (if applicable)
(832) 203 - 6400		( ) -

39. **TCEQ Programs and ID Numbers** Check all Programs and write in the permits/registration numbers that will be affected by the updates submitted on this form. See the Core Data Form instructions for additional guidance.

☐ Dam Safety	☐ Districts	☐ Edwards Aquifer	☐ Emissions Inventory Air	☐ Industrial Hazardous Waste
☐ Municipal Solid Waste	☒ New Source Review Air	☐ OSSF	☐ Petroleum Storage Tank	☐ PWS
☐ Sludge	☐ Storm Water	☐ Title V Air	☐ Tires	☐ Used Oil
☐ Voluntary Cleanup	☐ Waste Water	☐ Wastewater Agriculture	☐ Water Rights	☐ Other:

SECTION IV: Preparer Information

40. Name:	Denise Rogers		41. Title: Compliance Manager
42. Telephone Number	43. Ext./Code	44. Fax Number	45. E-Mail Address
(832) 203 - 6493		( ) -	denise.rogers@texasgulfterminals.com

SECTION V: Authorized Signature

46. By my signature below, I certify, to the best of my knowledge, that the information provided in this form is true and complete, and that I have signature authority to submit this form on behalf of the entity specified in Section II, Field 6 and/or as required for the updates to the ID numbers identified in field 39.

Company:	Texas Gulf Terminals Inc	Job Title:	Compliance Manager
Name(*In Print*):	Denise Rogers	Phone:	(832) 203-6493
Signature:	Denise Rogers	Date:	6/26/2018

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

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

I. Applicant Information		
A. Company or Other Legal Name: Texas Gulf Terminals Inc.		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Information: (☐ Mr. ☐ Mrs. ☒ Ms. ☐ Other:) _____		
Name: Denise Rogers		
Title: Compliance Manager		
Mailing Address: 1401 McKinney, Suite 1500		
City: Houston	State: TX	ZIP Code: 77010
Telephone No.: 832-203-6493	Fax No.:	
E-mail Address: denise.rogers@texasgulfterminals.com		
All permit correspondence will be sent via electronic copies unless hard copies are specifically requested through regular mail. The company official must initial here if hard copy correspondence is requested. _____		
C. Technical Contact Name Information: (☐ Mr. ☐ Mrs. ☒ Ms. ☐ Other:) _____		
Name: Denise Rogers		
Title: Compliance Manager		
Company Name: Texas Gulf Terminals Inc.		
Mailing Address: 1401 McKinney, Suite 1500		
City: Houston	State: TX	ZIP Code: 77010
Telephone No.: 832-203-6493	Fax No.:	
E-mail Address: denise.rogers@texasgulfterminals.com		
D. Site Name: Texas Gulf Terminals Project		
E. Area Name/Type of Facility:	☒ Permanent ☐ Portable	
For portable units, please provide the serial number of the equipment being authorized below.		
Serial No:	Serial No:	
F. Principal Company Product or Business: Offshore Marine Terminal		
Principal Standard Industrial Classification Code (SIC): 4612		
Principal North American Industry Classification System (NAICS): 486910		
G. Projected Start of Construction Date: TBD		
Projected Start of Operation Date: TBD		

I. Applicant Information (continued)		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: Site is approximately 14 miles offshore the coast of Texas, Southeast of Corpus Christi.		
City/Town: N/A	County: N/A	ZIP Code: N/A
Latitude (nearest second): 27˚ 28' 42.6"	Longitude (nearest second): 97˚ 00' 48.43"	
I. Account Identification Number (leave blank if new site or facility):		
J. Core Data Form		
Is the Core Data Form (Form 10400) attached? If No, provide customer reference number and regulated entity number (complete K and L).		☒ YES ☐ NO
K. Customer Reference Number (CN):		
L. Regulated Entity Number (RN):		
II. General Information		
A. Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.		☐ YES ☒ NO
B. Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.		☐ YES ☒ NO
C. Number of New Jobs: N/A		
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:		
State Senator: N/A	District No.: N/A	
State Representative: N/A	District No.: N/A	
III. Type of Permit Action Requested		
A. Mark the appropriate box indicating what type of action is requested.		
☒ Initial	☐ Amendment	☐ Revision (30 TAC § 116.116(e)
☐ Change of Location		☐ Relocation
B. Permit Number (if existing):		
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)*		
☒ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit		
☒ Prevention of Significant Deterioration (PSD)	☐ Hazardous Air Pollutant Major Source	
☐ PSD for greenhouse gases (GHGs)	☐ Other:_____	

III. Type of Permit Action Requested *(continued)*		
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC § 116.315(c).		☐ YES ☒ NO
E. Is this application for a change of location of previously permitted facilities?		☐ YES ☒ NO
If Yes, complete all parts of III.E.		
Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO," attach detailed information.		☐ YES ☐ NO
Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?		☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.		
List: N/A		
G. Are you permitting planned maintenance, startup, and shutdown emissions?		☐ YES ☒ NO
If Yes, attach information on any changes to emissions under this application as specified in VII and VIII.		
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability)		
Is this facility located at a site required to obtain a federal operating permit?		☒ YES ☐ NO ☐ To be determined
If Yes, list all associated permit number(s), attach pages as needed).		
Associated Permit No (s.):		
Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.		
☐ FOP Significant Revision	☐ FOP Minor	☐ Application for an FOP Revision
☐ Operational Flexibility/Off-Permit Notification		☐ Streamlined Revision for GOP
☒ To be Determined		☐ None

III. Type of Permit Action Requested *(continued)*	
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)***	
☐ GOP Issued ☐ GOP application/revision application submitted or under APD review	
☐ SOP Issued ☐ SOP application/revision application submitted or under APD review	
IV. Public Notice Applicability	
A. Is this a new permit application or a change of location application?	☒ YES ☐ NO
B. Is this application for a concrete batch plant? If Yes, complete all parts of V.D.	☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA § 112(g) permit, or exceedance of a PAL permit?	☐ YES ☒ NO
D. If this is an application for emissions of GHGs, select one of the following:	
☐ separate public notice (requires a separate application) ☒ consolidated public notice	
E. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☐ YES ☒ NO
If Yes, list the affected state(s) and/or Class I Area(s).	
List:	
F. Is this a state permit amendment application? If Yes, complete all parts of IV.F.	
Is there any change in character of emissions in this application?	☐ YES ☐ NO
Is there a new air contaminant in this application?	☐ YES ☐ NO
Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
List the total annual emission increases associated with the application ***(List all that apply and attach additional sheets as needed):***	
Volatile Organic Compounds (VOC):	
Sulfur Dioxide (SO_2):	
Carbon Monoxide (CO):	
Nitrogen Oxides (NO_x):	
Particulate Matter (PM):	
PM 10 microns or less (PM_{10}):	
PM 2.5 microns or less ($PM_{2.5}$):	
Lead (Pb):	
Hazardous Air Pollutants (HAPs):	
Other speciated air contaminants not listed above:	

V. Public Notice Information *(complete if applicable)*		
A. Responsible Person: (☐ Mr. ☐ Mrs. ☐ Ms. ☐ Other:) _____		
Name:		
Title:		
Company Name:		
Mailing Address:		
City:	State:	ZIP Code:
Telephone No.:	Fax No.:	
E-mail Address:		
B. Technical Contact: (☐ Mr. ☐ Mrs. ☐ Ms. ☐ Other:) ___		
Name:		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
Telephone No.:	Fax No.:	
E-mail Address:		
C. Name of the Public Place:		
Physical Address *(No P.O. Boxes)*:		
City:	County:	ZIP Code:
The public place has granted authorization to place the application for public viewing and copying.		☐ YES ☐ NO
The public place has internet access available for the public.		☐ YES ☐ NO
D. Concrete Batch Plants, PSD, and Nonattainment Permits		
County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable:		
Mailing Address:		
City:	State:	ZIP Code:

V. Public Notice Information *(complete if applicable)*		
D. Concrete Batch Plants, PSD, and Nonattainment Permits *(continued)*		
Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
Provide the name, mailing address of the chief executive for the location where the facility is or will be located.		
Chief Executive:		
Mailing Address:		
City:	State:	ZIP Code:
Provide the name, mailing address of the Indian Governing Body for the location where the facility is or will be located.		
Indian Governing Body:		
Mailing Address:		
City:	State:	ZIP Code:
Identify the Federal Land Manager(s) for the location where the facility is or will be located.		
Federal Land Manager(s):		
E. Bilingual Notice		
Is a bilingual program required by the Texas Education Code in the School District?		☐ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?		☐ YES ☐ NO
If Yes, list which languages are required by the bilingual program?		
VI. Small Business Classification *(Required)*		
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?		☐ YES ☒ NO
B. Is the site a major stationary source for federal air quality permitting?		☒ YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?		☒ YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?		☒ YES ☐ NO

VII. Technical Information	
A. The following information must be submitted with your Form PI-1 ***(this is just a checklist to make sure you have included everything)***	
☒ Current Area Map ☒ Plot Plan ☒ Existing Authorizations ☒ Process Flow Diagram ☒ Process Description ☒ Maximum Emissions Data and Calculations ☒ Air Permit Application Tables ☒ Table 1(a) (Form 10153) entitled, Emission Point Summary ☐ Table 2 (Form 10155) entitled, Material Balance ☒ Other equipment, process or control device tables	
B. Are any schools located within 3,000 feet of this facility?	☐ YES ☒ NO
C. Maximum Operating Schedule:	
Hour(s): 24	Day(s): 365
Week(s): 52	Year(s):
Seasonal Operation? If Yes, please describe in the space provide below.	☐ YES ☒ NO
Hour(s):	Day(s):
Week(s):	Year(s):
D. Have the planned MSS emissions been previously submitted as part of an emissions inventory?	☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.	
MSS Facility(s) or Activity	**Year(s)**
E. Does this application involve any air contaminants for which a disaster review is required?	☐ YES ☒ NO
If Yes, list which air contaminants require a disaster review.	

VII.	**Technical Information *(continued)***	
F.	Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)?	☐ YES ☒ NO
G.	Are emissions of GHGs associated with this project subject to PSD?	☐ YES ☒ NO
If "yes," provide a list of all associated applications for this project:		
See attachments		
VIII.	**State Regulatory Requirements** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non-applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*	
A.	Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?	☒ YES ☐ NO
B.	Will emissions of significant air contaminants from the facility be measured?	☐ YES ☒ NO
C.	Is the Best Available Control Technology (BACT) demonstration attached?	☒ YES ☐ NO
D.	Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?	☒ YES ☐ NO
IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non-applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
A.	Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?	☐ YES ☒ NO
B.	Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?	☐ YES ☒ NO
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☐ YES ☒ NO
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA § 112(g)] requirements apply to this application?	☒ YES ☐ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	
Is the estimated capital cost of the project greater than $2 million dollars?		☒ YES ☐ NO
If Yes, submit the application under the seal of a Texas licensed P.E.		

XI. Permit Fee Information	
Check, Money Order, Transaction Number, ePay Voucher Number: N/A	
Fee Amount: $ N/A	
Paid online? N/A	☐ YES ☐ NO
Company name on check:	
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☐ YES ☐ NO ☒ N/A

XII. Delinquent Fees and Penalties

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

XIII. Signature

The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7; the Texas Health and Safety Code, Chapter 382, the Texas Clean Air Act (TCAA) the air quality rules of the Texas Commission on Environmental Quality; or any local governmental ordinance or resolution enacted pursuant to the TCAA. I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.

Name: Denise Rogers

Signature: Denise Rogers
Original Signature Required

Date: 6/26/2018

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	July 2018	**Permit No.:**	TBD	**Regulated Entity No.:**	
Area Name:	Texas Gulf Terminals Project			**Customer Reference No.:**	CN605490085

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

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) POUND**	**(B) TPY**
LOADFUG	LOADFUG	Marine Loading	VOC	7774	10808
			H_2S	0.17	0.24

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	July 2018	**Permit No.:**	TBD	**Regulated Entity No.:**	
Area Name:	Texas Gulf Terminals Project			**Customer Reference No.:**	CN605490085

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

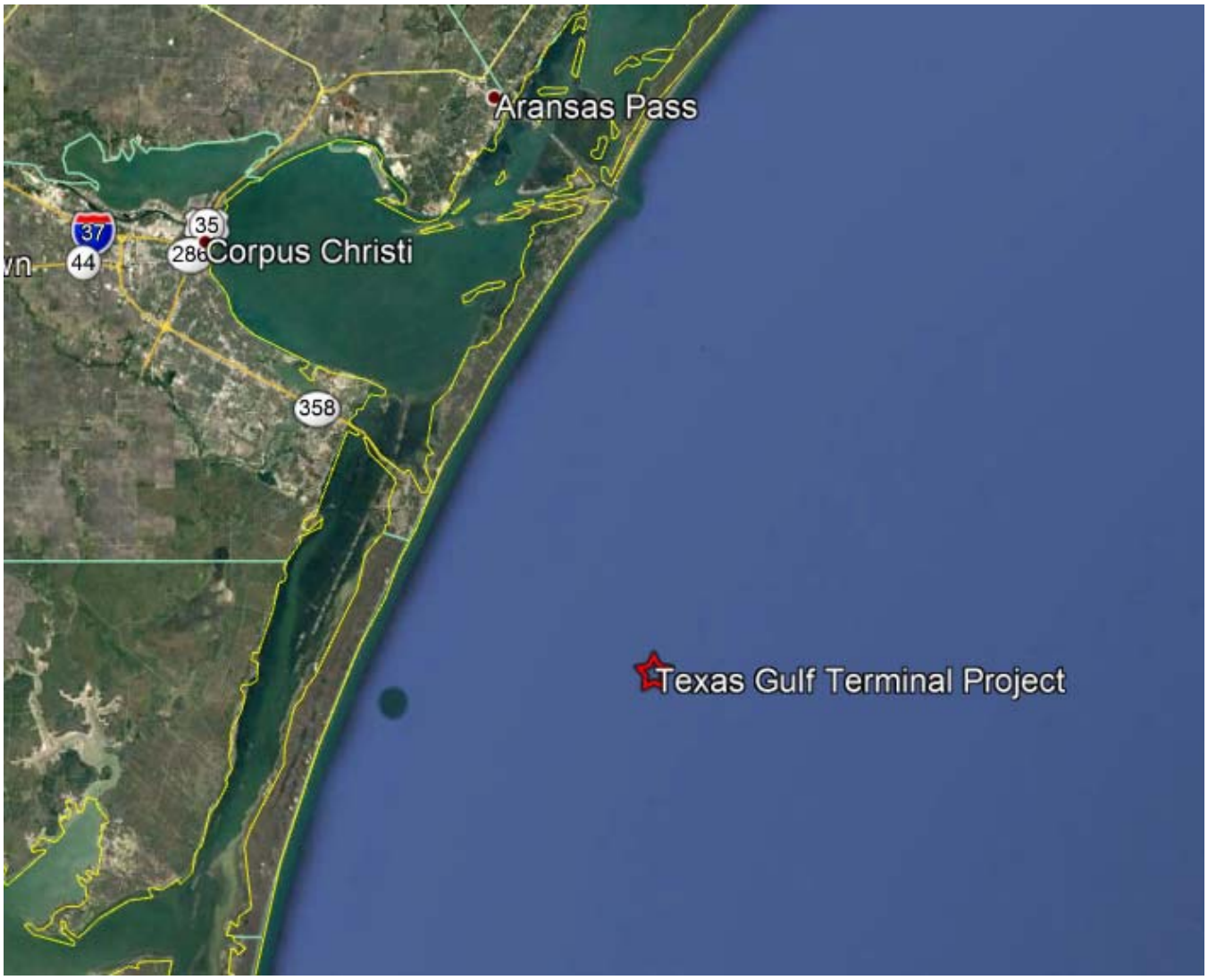
AIR CONTAMINANT DATA			**EMISSION POINT DISCHARGE PARAMETERS**										
1. Emission Point			**4. UTM Coordinates of Emission Point**			**Source**							
						5. Building	**6. Height Above**	**7. Stack Exit Data**			**8. Fugitives**		
EPN (A)	**FIN (B)**	**Name (C)**	**Zone**	**East (Meters)**	**North (Meters)**	**Height (Ft.)**	**Ground (Ft.)**	**Diameter (Ft.) (A)**	**Velocity (FPS) (B)**	**Temperature (°F) (C)**	**Length (Ft.) (A)**	**Width (Ft.) (B)**	**Axis Degrees (C)**
LOADFUG	LOADFUG	Marine Loading	14	696278	3041006	120.0	0.0	4.7	50.0	455	360646	283707	0

EPN = Emission Point Number
FIN = Facility Identification Number

3. PROJECT LOCATION

The proposed DWP would be positioned within territorial seas of the OCS Mustang Island Area TX3 (Gulf of Mexico), within the Bureau of Ocean Energy Management (BOEM) block number 823. The proposed DWP is positioned at Latitude N27° 28’ 42.60” and Longitude W97° 00’ 48.43”, approximately 12.7 nautical miles (14.62 statute miles) off the coast of North Padre Island in Kleberg County, Texas. Figure 3-1 provided below shows the location of the DWP terminal.

Figure 3-1. Location of the DWP Terminal



4.1. CRITERIA POLLUTANTS EMISSIONS SUMMARY

The proposed SPM buoy system will enable Very Large Crude Carriers (VLCCs) to be fully and completely loaded directly with crude oil/condensate from the SPM. The crude oil/condensate will be supplied to the SPM buoy system from the Onshore Storage Terminal Facility (OSTF), through a pipeline infrastructure, and to the SPM buoy system. Two (2) 30-inch-diameter pipelines will each be capable of 30,000 bph flow rate allowing an overall system crude oil/condensate delivery capacity of 60,000 bph to vessels connected to the proposed SPM buoy system's loading hose. Vessels will be moored to the proposed SPM buoy system via mooring hawsers. Crude oil will be routed from subsea PLEM via two 24-inch ID flexible hoses to SPM buoy. Floating hoses will extend from the SPM buoy system to the moored vessel to allow for the loading of crude oil/condensate. The project will have a crude oil/condensate loading capacity of 60,000 bph and 192 million barrels per year. The project will be able to load up to approximately 96 large vessels per year.

4.2. PROJECT DESCRIPTION

The proposed project includes 14.62 miles of two (2) new paralleling 30-inch diameter offshore pipelines and the DWP.

Offshore pipelines - The proposed project requires the ability to export multiple grades of crude oil/condensate. As such, the proposed offshore pipeline infrastructure will comprise a dual pipeline system to allow for the flushing of lines of one crude grade back to the Onshore Storage Terminal Facility (OSTF). Under normal operations, the OSTF will pump crude oil/condensate through both offshore pipelines to the PLEM and SPM buoy system for the loading of vessels moored at the DWP.

DWP - The proposed SPM buoy system will consist of a Pipeline End Manifold (PLEM) system, mooring hawsers, and floating hoses to allow for the loading of crude oil to vessels connected to the proposed SPM buoy system's loading hose. The proposed SPM buoy system will be of the Catenary Anchor Leg Mooring (CALM) type permanently moored with a symmetrically arranged six-leg anchor chain system extending to pile anchors fixed on the seafloor. The proposed SPM buoy system will consist of inner and outer cylindrical shells subdivided into twelve equal-sized watertight radial compartments. A rotating table will be affixed to the SPM buoy and allow for the connection of moored vessels to the SPM buoy system via mooring hawsers. A series of floating hose strings equipped with marine break-away couplings will be utilized for the transfer of crude oil from the SPM buoy system to the moored vessel. Floating hoses will be equipped with strobe lights (Winkler Lights) at 15-foot intervals for detection at night and periods of low-light. The PLEM system that will serve as the connection point between subsea pipelines and the SPM buoy system through a series of 24-inch-diameter submarine hoses. The PLEM system would be a steel frame structure positioned directly beneath the proposed SPM buoy system and would be anchored directly to the seafloor with piles.

The only primary emissions involved in the proposed project are the VOC emissions resulting from the loading of crude oil/condensate from the SPM buoy system onto a VLCC.

4.3. ALTERNATIVES ANALYSIS

As mentioned in the project background, the purpose of the proposed SPM buoy system will be to fully and directly load VLCCs with crude oil/condensate for export. The proposed SPM buoy system is unique and different from current crude oil/condensate export operations that are currently conducted in the United States.

Because of their size (2 MMbbls fully loaded), VLCCs are used for long haul trips to transport cargos long distances across the globe economically. However, their immense size and drat limitations prevents VLCCs from navigating to onshore terminals to be loaded fully. Therefore, VLCCs are currently loaded by lightering, which is the process of using smaller ships to shuttle crude oil/condensate from onshore terminals out to the VLCC. As part of the lightering, crude oil/condensate is loaded onto the VLCC via ship-to-ship (STS) transfer in off-shore waters with a depth that VLCCs can navigate while fully loaded. Emissions from STS transfer during lightering operations are not regulated by CAA regulations and therefore result in uncontrolled emissions of VOC.

Lightering is the current practice for loading VLCCs with crude oil/condensate for export. The STS transfers that occur during the lightring operations generate similar emissions as will occur during when the proposed SPM buoy system conducts its marine tank vessel loading transfer process. However, lightering generates many other emissions during ship movements that do not occur with the SPM buoy system. When comparing wholistic emissions from the entire lightering process to the entire process associated with the use of the proposed SPM buoy system, the benefit of the proposed SPM buoy system is clear. Not only does the proposed SPM buoy system reduce the total amount of air emissions, but the proposed SPM buoy system also reduces ship channel traffic and results in a safer and more efficient process to fully load a VLCC with crude oil/condensate for export.

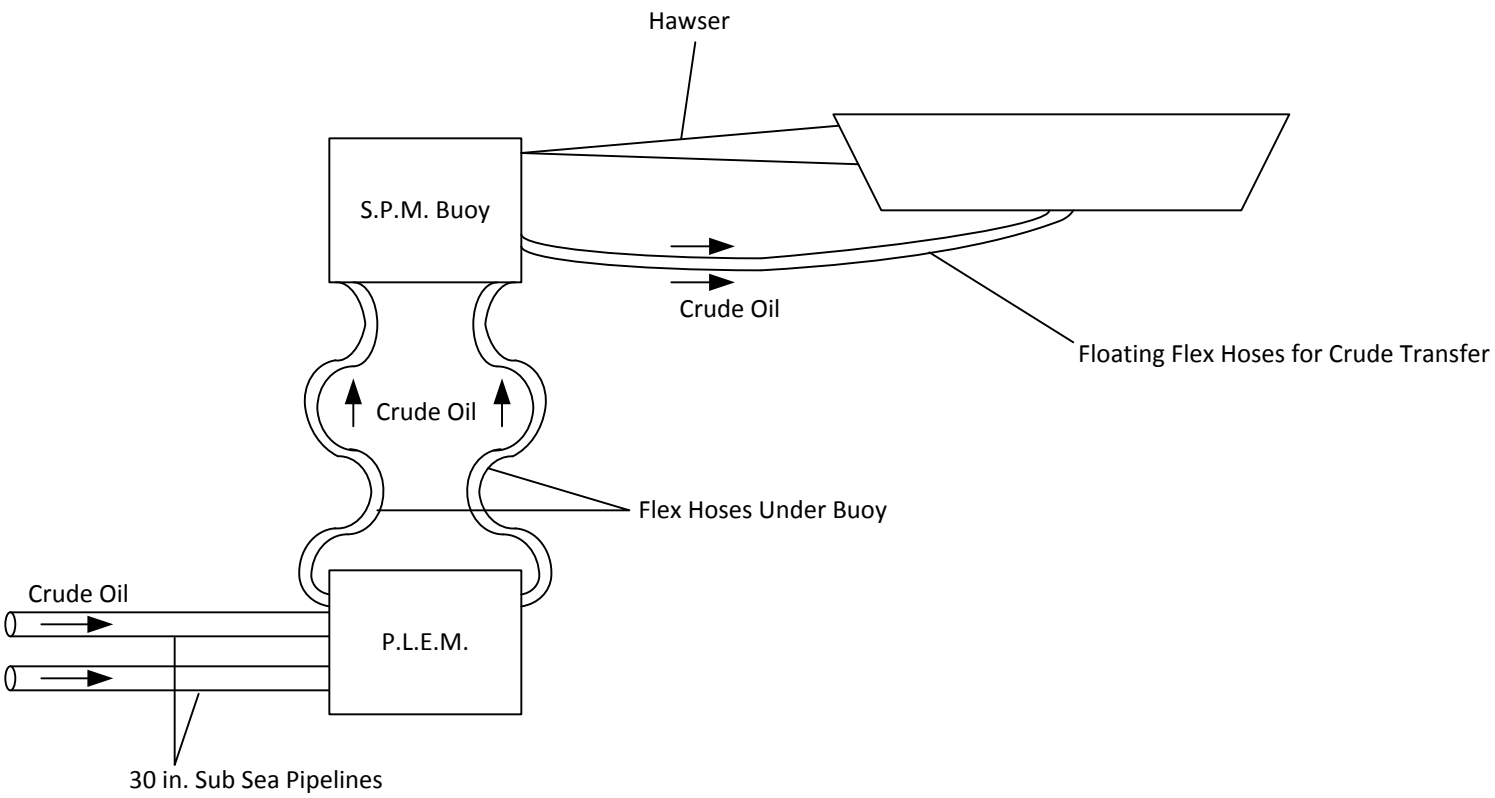
The additional air emissions impacts of lightering compared to the proposed SPM buoy system are generated from the additional combustion emissions required to shuttle the crude oil/condensate on smaller oil tankers from onshore terminals out to the VLCC. With the proposed SPM buoy system, the only tanker involved is the VLCC and it does not have to come any closer to shore than the location of the proposed SPM buoy system, saving on propulsion fuel use. Furthermore, any emissions from the VLCC will be produced further away from the public than those generated by lightering vessels. The table below shows a comparison of the wholistic potential emissions from lightering and the proposed SPM buoy system.

Emissions shown below include sources of air emissions that are NOT part of the DWP source, which is just the proposed SPM buoy system and its loading operations. Additional sources of emissions (which are not regulated under the scope of this application) such as auxiliary vessel emissions and support vessel emissions, are provided for informational purposes only for the alternatives analysis comparison. Detailed emission calculations for the alternatives emissions analysis are provided under separate cover in the *Air Quality Information for Environmental Impact Statement, Appendix A*.

Table 4-1 - Alternatives Emissions Analysis

Description of Activity	VOC tpy	NOx tpy	CO tpy	PM tpy	PM_{10} tpy	$PM_{2.5}$ tpy	SO_2 tpy	Total HAPs tpy	CO_2e tpy
Proposed Project Design									
Proposed Project Design - Total	10,855	1,673	343	69	55	52	88	201	134,484
Alternative Lightering Scenario Total[1]	13,246	3,136	579	127	111	104	124.9	248	251,871
Emissions Reductions (TPY) from Proposed SPM Design	**2,424**	**1,463**	**236**	**58**	**56**	**52**	**37**	**47**	**117,387**

1. Accounts for full and partial lightering of VLCC based on a representation of historical lightering operations. Emissions represent the emissions STS loading and any additional emissions generated in the lightering process (i.e., loading of lightering vessel onshore, propulsion of lightering vessel, etc.).



Texas Gulf Terminals Inc.

Process Flow Diagram

Trinity Consultants

Project 184403.0005
April 2018

Legend

- Onshore Storage Facility Property
- Pump Station
- HDD Pipeline Section
- Onshore Segment
- Inshore Laguna Madre Segment
- Inshore North Padre Island Segment
- Offshore Segment
- SPM System and Safety Zone
- Existing Pipelines (RRC)
- Parks, NWRs, WMAs
- 90ft Depth Contour
- Federal/State Line
- GLO Lease Tracts
- Federal Lease Blocks

N

Coordinate System: NAD 1983 StatePlane Texas South Central FIPS 4204 Feet
Projection: Lambert Conformal Conic
Datum: North American 1983
Units: Foot US

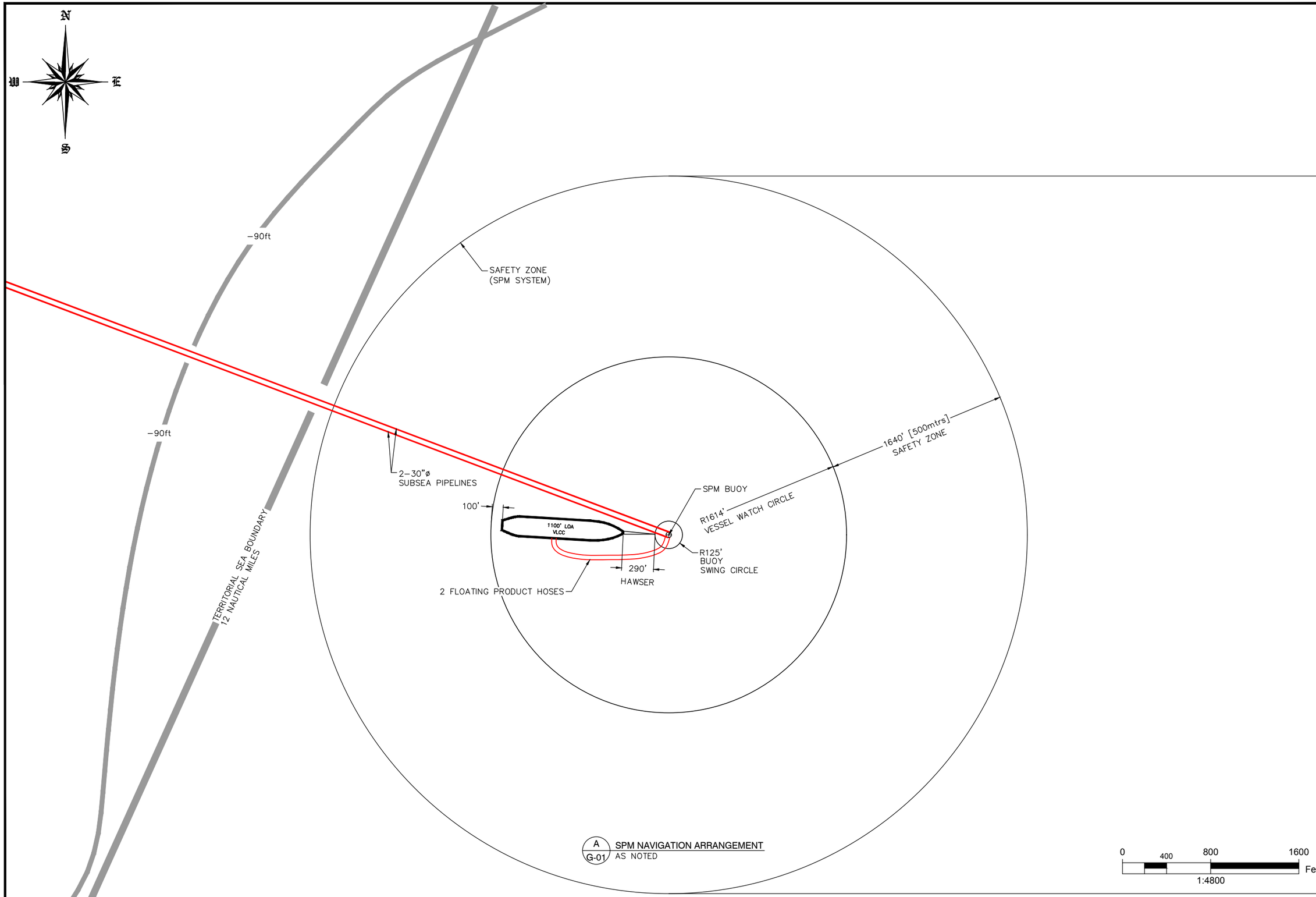
0 5,000 10,000 20,000 Feet

Project Component Overview Map
Texas Gulf Terminals Inc
Texas Gulf Terminals Project

Date: May 21, 2018
Prepared By: CG
Project: TGTI
1 inch = 10,000 feet

LLOYD ENGINEERING, INC.

Document Path: G:\Traffigura SPM Project\Overview Map\ProjectComponentsMap.mxd



A
G-01
SPM NAVIGATION ARRANGEMENT
AS NOTED

NO.	DESCRIPTION	DATE	APPR
A	ISSUED FOR REVIEW	MM/DD/YY	-

ISSUED FOR REVIEW

SEAL

TEXAS GULF TERMINALS INC.

CLIENT

TEXAS GULF TERMINALS PROJECT

SPM ARRANGEMENT DETAIL

LLOYD ENGINEERING, INC
HOUSTON TEXAS, USA
LICENSE NO. F-002846

DESIGN BY:	SL
DRAWN BY:	–
DATE:	MARCH 2018
SCALE:	AS NOTED @ 22"X34"
SHEET:	2 OF 2
DRAWING NO:	
REV. A	2

5.1. MARINE LOADING

Emissions from marine loading of crude oil/condensate are calculated based on TCEQ's Air Permit Technical Guidance for Chemical Sources: Loading Operations (October 2000) using the following equation from U.S. EPA's AP-42, Section 5.2:

$$L = 12.46 \times S \times P \times M/T$$

where:

L = Loading Loss (lb/10^3 gal of liquid loaded)
S = Saturation factor
P = True vapor pressure of liquid loaded (psia)
M = Molecular weight of vapors (lb/lb-mole)
T = Temperature of bulk liquid loaded (R)

A saturation factor of 0.2 is used for submerged loading using ships. A maximum true vapor pressure of 11 psia is used for crude oil/condensate loading.

6. FEDERAL NEW SOURCE REVIEW ANALYSIS

The proposed SPM buoy system will be located approximately 14 miles from the coast of Kleberg County. Due to unavailability of attainment/non-attainment information in project area offshore, TGTI proposes to use the attainment status of the nearest County onshore, which is Kleberg County. Kleberg County is considered in attainment or unclassified for all FNSR pollutants. Therefore, the project will not be subject to Non-attainment New Source Review (NNSR), and will only be subject to Prevention of Significant Deterioration (PSD) review if it is determined that emissions of criteria pollutants from the facility will trigger the major source threshold. A major stationary source is defined as either one of the sources identified in 40 CFR 51.166 and which has a PTE of 100 tons or more per year of any regulated pollutant, or any other stationary source which has a PTE of 250 tpy or more of a regulated pollutant. The proposed project is not on the list of 28 source categories listed in 40 CFR 51.166 which have a major source threshold of 100 tpy. Therefore, the proposed project will be subject to PSD if it is determined that emissions form the facility will exceed 250 tpy of any regulated pollutant.

The only FNSR pollutant from the proposed project will be VOC. Based on potential air emissions from the facility, the project will be subject to preconstruction review under the federal PSD regulations since potential VOC emissions will be greater than the 250 ton per year PSD major source threshold. Once one pollutant exceeds the PSD major source threshold, remaining pollutants are then compared to their significant emission rate (SER) to determine if the new major stationary source has the potential to emit the pollutants in significant amounts. PSD permitting is applicable to any other pollutants that exceed their respective SER.[2] As shown in Table 6-1, the only pollutant which is subject to PSD permitting is VOC.

Since VOC emissions are expected to be greater than 250 tpy, an ozone impacts analysis has to be performed. TGTI performed an ozone impacts analysis and it has been submitted under separate cover.

Table 6-1. FNSR PSD Analysis Summary

	NO_X (tpy)	CO (tpy)	VOC (tpy)	SO_2 (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	H_2S (tpy)	H_2SO_4 (tpy)
New Sources								
Loading	--	--	10,808	--	--	--	0.24	--
Fugitives	--	--	0.22	--	--	--	--	--
Total Project Increases:	--	--	10,808	--	--	--	0.24	--
PSD Threshold	250	250	250	250	250	250	10	7
PSD Review Required	N/A	N/A	Yes	N/A	N/A	N/A	N/A	N/A

[2] 40 CFR 52.21(b)(23)

7. FEDERAL (TOP-DOWN) BACT

This section discusses the regulatory basis for BACT, approach used in completing the BACT analyses, and the BACT analyses for the proposed facility. Supporting documentation is included in Appendix C.

7.1. BACT DEFINITION

The requirement to conduct a BACT analysis is set forth in the PSD regulations [40 CFR 52.21(j)(2)]:

> *(j) Control Technology Review.*
> *(2) A new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts.*

BACT is defined in the PSD regulations [40 CFR 52.21(b)(12)] as:

> *...an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61.*
> [primary BACT definition]
>
> *If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.*
> [allowance for secondary BACT standard under certain conditions]

The primary BACT definition can be best understood by breaking it apart into its separate components.

7.1.1. Case-By-Case Basis

> *a case-by-case basis, taking into account energy, environmental and economic impacts and other costs*

Unlike many of the Clean Air Act programs, the PSD program's BACT evaluation is case-by-case. As noted by EPA,

The case-by-case analysis is far more complex than merely pointing to a lower emissions limit or higher control efficiency elsewhere in a permit or a permit application. The BACT determination must take into account all of the factors affecting the facility …. The BACT analysis, therefore, involves judgment and balancing.

To assist applicants and regulators with the case-by-case process, in 1987 EPA issued a memorandum that implemented certain program initiatives to improve the effectiveness of the PSD program within the confines of existing regulations and state implementation plans. Among the initiatives was a "top-down" approach for determining BACT. In brief, the top-down process suggests that all available control technologies be ranked in descending order of control effectiveness. The most stringent or "top" control option is the default BACT emission limit unless the applicant demonstrates, and the permitting authority in its informed opinion agrees, that energy, environmental, and/or economic impacts justify the conclusion that the most stringent control option is not achievable in that case. Upon elimination of the most stringent control option based upon energy, environmental, and/or economic considerations, the next most stringent alternative is evaluated in the same manner. This process continues until BACT is selected.

The five steps in a top-down BACT evaluation can be summarized as follows:

- Step 1. Identify all possible control technologies
- Step 2. Eliminate technically infeasible options
- Step 3. Rank the technically feasible control technologies based upon emission reduction potential
- Step 4. Evaluate ranked controls based on energy, environmental, and/or economic considerations
- Step 5. Select BACT

While the top-down BACT analysis is a procedural approach suggested by the EPA policy, this approach is not specifically mandated as a statutory requirement of the BACT determination. It should be noted that the BACT limit is an emissions limitation or work practice standard and ultimately, does not require the installation of any specific control devices.

7.1.2. Achievable

based on the maximum degree of reduction …[that DEP] … determines is achievable … through application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques

BACT is to be set at the lowest value that is achievable. However, there is an important distinction between emission rates achieved at a specific time on a specific unit, and an emission limitation that a unit must be able to meet continuously over its operating life. As discussed by the D.C. Circuit Court of Appeals

> *In National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980), we said that where a statute requires that a standard be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur."*[3]

EPA has reached a similar conclusion in prior determinations for PSD permits.

> *Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured 'emissions rates,' which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the 'emissions limitation' determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility. Accordingly, because the "emissions limitation" is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.*[4]

Thus, BACT must be set at the lowest feasible emission rate recognizing that the facility must be in compliance with that limit for the lifetime of the facility on a continuous basis. While viewing individual unit performance can be instructive in evaluating what BACT might be, any actual performance data must be viewed carefully, as rarely will the data be adequate to truly assess the performance that a unit will achieve during its entire operating life. While statistical variability of actual performance can be used to infer what is "achievable," such testing requires a detailed test plan akin to what teams in EPA use to develop MACT standards over a several year period, and is far behind what is reasonable to expect of an individual source. In contrast to limited snapshots of actual performance data, emission limits from similar sources can reasonably be used to infer what is "achievable."[5]

To assist in meeting the BACT limit, the source must consider production processes or available methods, systems or techniques, as long as those considerations do not redefine the source.

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[3] As quoted in Sierra Club v. EPA (97-1686).

[4] EPA Environmental Appeals Board decision, *In re: Newmont Nevada Energy Investment L.L.C.* PSD Appeal No. 05-04, decided December 21, 2005. Environmental Administrative Decisions Volume 12, Page 442.

[5] Emission limits must be used with care in assessing what is "achievable." Limits established for facilities which were never built must be viewed with care, as they have never been demonstrated and that company never took a significant liability in having to meet that limit. Likewise, permitted units which have not yet commenced construction must also be viewed with care for similar reasons.

7.1.3. Floor

Emissions [shall not] *exceed* ...[40 CFR Parts 60, 61, 63]

The least stringent emission rate allowable for BACT is any applicable limit under Part 60 (NSPS) or Part 61 (NESHAP). State SIP limitations must also be considered when determining the floor, such as those in Chapter 62 of the F.A.C. Although the definition of BACT in 40 CFR 52.21(b)(12) does not explicitly include NESHAPs in 40 CFR Part 63, limits for PSD pollutants set by this rule are often considered as well.

7.2. BACT REQUIREMENT

The BACT requirement applies to each new and modified emission unit for which there are emissions increases of pollutants subject to PSD review. The proposed SPM buoy system is subject to PSD review for VOC only.

7.3. BACT ASSESSMENT METHODOLOGY

The following sections provide detail on the BACT assessment methodology utilized in preparing the BACT analysis for the proposed SPM buoy system. As previously noted, the minimum emission limit to be considered in a BACT assessment must result in an emission rate less than or equal to any applicable NSPS or NESHAP emission rate for the source. Since, there are no applicable NSPS or NESHAP emission rates for the proposed SPM buoy system, there is no applicable BACT floor.[6]

7.3.1. Identification of Potential Control Technologies

Potentially applicable emission control technologies were identified by researching the EPA control technology database, technical literature, control equipment vendor information, state permitting authority files, and by using process knowledge and engineering experience. The Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC), a database made available to the public through the EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These technologies are grouped into categories by industry and can be referenced in determining what emissions levels were proposed for similar types of emissions units.

TGTI performed searches of the RBLC database to start identifying the emission control technologies and emission levels that were determined by permitting authorities as BACT within the past ten years for emission sources comparable to the proposed sources. The following emission source categories were searched:

- Petroleum Liquid Marketing (RBLC Code 42.004)
- Volatile Organic Liquid Marketing (RBLC Code 42.010)

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[6] See Regulatory Applicability portion of application narrative.

- Other Liquid Marketing Sources (RBLC Code 42.999)

TGTI also searched the following phrases in the RBLC database:

- SPM
- Mooring
- Off-shore
- Off-shore Marine Loading
- Marine Terminal
- Vessel Loading
- Marine Off-loading
- Marine Tanker
- Tanker Ships
- Deepwater Port
- Deepwater Marine Loading
- Subsea Loading
- Production Platform
- Single Point Mooring
- Mooring System
- Off-shore Loading
- Off-shore Terminal
- Marine Loading
- Marine Vessel
- Loading Buoy
- Tanker Loading
- Deepwater
- Deepwater Loading
- Deepwater Terminal
- Export Tanker

7.3.2. Technical Feasibility Analysis

The technical feasibility of control options identified was evaluated based on the New Source Review Workshop Manual, 1990 (the Manual). The Manual identifies two key concepts in determining if an undemonstrated technology is feasible: "availability" and "applicability." A technology is "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. Further, an available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. Only if a technology is both available and applicable is it considered technically feasible.

The Manual leaves the decisions about technical feasibility up to the review authority and states that in the absence of an explanation of why a control option is technically infeasible, it can be presumed the control option is technically feasible. The applicant is responsible for providing a factual demonstration of infeasibility based on commercial unavailability and/or unusual circumstances which make the control option technically infeasible. Such a demonstration can involve an evaluation of the pollutant-bearing gas stream characteristics or unresolvable technical difficulty applying the control such as the size of the unit, location of the proposed site, and operating problems related to specific circumstances of the source. With respect to control devices still under research and development, the Manual states the following:

> *A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review.*

TGTI has completed a technical evaluation of each of the identified control devices as it pertains to the proposed SPM buoy system.

7.4. DEFINING THE SOURCE

Historical practices, as well as recent court rulings, have been clear that a key foundation of the BACT process is that BACT is applied to the type of source proposed by the applicant, and that redefining the source is not appropriate in a BACT determination.

Though BACT is based on the type of source as proposed by the applicant, the scope of the applicant's ability to define the source is not absolute. As EPA notes, a key task for the reviewing agency is to determine which parts of the proposed process are inherent to the applicant's purpose and which parts may be changed without changing that purpose. As discussed by EPA in an opinion on the Prairie State project,

> *We find it significant that all parties here, including Petitioners, agree that Congress intended the permit applicant to have the prerogative to define certain aspects of the proposed facility that may not be redesigned through application of BACT and that other aspects must remain open to redesign through application of BACT.*[7]
>
> *…*
>
> *When the Administrator first developed [EPA's policy against redefining the source] in Pennsauken, the Administrator concluded that permit conditions defining the emissions control systems "are imposed on the source as the applicant has defined it" and that "the source itself is not a condition of the permit.*[8]

Given that some parts of the project are not open for review under BACT, EPA then discusses that it is the permit reviewer's burden to define the boundary. Based on precedent set in multiple prior EPA rulings (e.g., Pennsauken County Resource Recovery [1988], Old Dominion Electric Coop [1992], Spokane Regional Waste to Energy [1989]), EPA states the following in Prairie State.

> *For these reasons, we conclude that the permit issuer appropriately looks to how the applicant, in proposing the facility, defines the goals, objectives, purpose, or basic design for the proposed facility. Thus, the permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility, and therefore, the permit*

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[7] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 26.

[8] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 29.

issuer must discern which design elements are inherent to that purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility[9]

EPA's opinion in Prairie State was upheld on appeal to the Seventh Circuit Court of Appeals, where the court affirmed the substantial deference due the permitting authority on defining the demarcation point.[10] Taken as a whole, the permitting agency is tasked with determining which controls are appropriate, but the discretion of the agency does not extend to a point requiring the applicant to redefine the source.

7.4.1. Proposed Source

TGTI is proposing to build a new a SPM buoy system for off-shore marine loading of crude/condensate located approximately 14 miles off-shore of the outer bank of Mustang Island. It is essential to the scope of the project that the proposed facility is an off-shore facility. Being located approximately 14 miles off-shore enables the SPM buoy system to fully and directly load VLCCs, which are not possible at any existing on-shore facilities because of water depth limitations. The proposed SPM buoy system is a single buoy for which a vessel can moor itself to for loading of crude oil/condensate. TGTI considers mooring system designs other than an SPM buoy system to be outside the scope of the proposed source since other mooring systems would require a complete redesign and reevaluation of the project.

The SPM buoy system itself will contain no engines, pumps, or loading equipment other than the necessary hoses to connect the vessel to subsea pipeline. All pumps and storage tanks will be located onshore at a separate facility. Emissions from auxiliary sources (miscellaneous tanks on the tanker vessel, combustion emissions from vessel engines, combustion emissions from tug boat engines, etc) are not included in this BACT analysis because they are not part of the scope for the proposed source and are considered secondary emissions.

7.5. SHIP LOADING – VOC BACT

7.5.1. Background on Pollutant Formation

The loading of organic liquids such as crude oil/condensate into marine vessels generates emissions of VOC organic vapors are displaced in the process. The composition of the displaced vapors are a mix of vapors formed in the empty ship from residual product from previous loads and vapors generated in the

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[9] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 30. See also EPA Environmental Appeals Board decision, *In re: Desert Rock Energy Company LLC*. PSD Appeal Nos. 08-03, 08-04, 08-05 & 08-06, decided Sept. 24, 2009, page 64 ("The Board articulated the proper test to be used to [assess whether a technology redefines the source] in *Prairie State*.").

[10] *Sierra Club v. EPA and Prairie State Generating Company LLC*, Seventh Circuit Court of Appeals, No. 06-3907, August 24, 2007. Rehearing denied October 11, 2007.

ship as the product is loaded. Therefore the following parameters effect the evaporative losses generated from loading operations:

- Physical and chemical characteristics of the previous cargo,
- Method of unloading the previous cargo,
- Operations to transport the empty carrier to a loading terminal,
- Method of loading the new cargo, and
- Physical and chemical characteristics of the new cargo.

For the proposed SPM buoy system, the method of loading new cargo is the only variable within TGTI's control that can influence the emissions from the loading operations. In splash loading, the fill pipe is partly loaded into the top of the tank and the cargo is allowed to splash onto the liquid surface in the tank. This creates high degrees of turbulence on the surface and increased surface area of liquid to vapor contact during the loading. The increased surface area leads to an increased partial pressure (higher saturation) from product vapors (VOC). Submerged loading allows the tank to be loaded without impacting the surface of the liquid. Submerged loading can be accomplished by either submerged pipe fill or bottom loading. Both methods of submerged loading load the cargo such that the fill pipe opening is below the liquid surface level and therefore does not disturb the liquid surface. As a result, the surface area of liquid product exposed to air is considerably lower than compared to splash loading.

7.5.2. Identification of Potential Control Technologies

Using the RBLC search, permit reviews, and a review of technical literature, potentially applicable VOC control technologies for marine loading operations were identified based on principles of control technology and engineering experience for marine loading.

Potential VOC mitigation options identified were:

- Submerged Loading

Potential VOC reduction options identified were:

- Vapor Recovery Unit (VRU)
- Vapor Combustion Unit (VCU)

These control technologies are briefly discussed in the following sections.

7.5.2.1. Submerged Loading

Submerged loading in the case of the proposed SPM buoy system is a loading procedure by which the discharge of crude oil/condensate into the VLCC tanks is located at or below the surface of the crude oil/condensate in the vessel. By discharging the crude oil/condensate into the hold at a point below the surface of the liquid, VOC emissions are mitigated compared to splash loading because the surface of the cargo is not disturbed in submerged loading. Compared to splash loading, this minimizes the generation

of VOC emissions because it reduces the surface area liquid/vapor interface and thus minimizes the volatilization of hydrocarbons from the liquid.

7.5.2.2. VOC Management Plan

Regulation 15.6 of the International Convention for the Prevention of Pollution from Ships (MARPOL) Annex VI requires that all tankers carrying crude oil have an approved and effectively implemented ship specific VOC Management Plan covering at least the points given in the regulation. Guidelines for the development of VOC Management Plans is given in Marine Environmental Protection Committee Resolution 185(59) (MEPC.185(59)) and additional information on systems and operations of VOC Management Plans is given in MEPC.1/Circ.680. For reference, MEPC.185(59) and MEPC.1/Circ.680 have been provided as Appendices C and D, respectively.

The VOC Management Plan is a ship-specific management plan designed to ensure that the operation of a tanker, to which Regulation 15 of MARPOL Annex VI applies, prevents or minimizes VOC emissions to the extent possible. To comply with the plan, the loading and carriage of cargoes which generate VOC emissions should be evaluated and procedures written to ensure that the operations of a ship follow best management practices for preventing and minimizing VOC emissions to the extent possible. With respect to the loading operations at the proposed SPM buoy system, Rule 1.4. of the VOC Management Plan Guideline (MEPC.185(59)) states that while maintaining the safety of the ship, the VOC Management Plan should encourage and set forth the following best management practices as appropriate:

1. The loading procedures should take into account potential gas releases due to low pressure and, where possible, the routing of oil from crude oil manifolds into the tanks should be done so as to avoid or minimize excessive throttling and high flow velocity in pipes;
2. The ship should define a target operating pressure for the cargo tanks. This pressure should be as high as safely possible and the ship should aim to maintain tanks at this level during the loading and carriage of relevant cargo;
3. When venting to reduce tank pressure is required, the decrease in the pressure in the tanks should be as small as possible to maintain the tank pressure as high as possible;
4. The amount of inert gas added should be minimized. Increasing tank pressure by adding inert gas does not prevent VOC release but it may increase venting and therefore increase VOC emissions.

Technical information for the development of VOC Management Plans for tankers carrying crude oil are provided in MEPC.1/Circ.680 (Appendix D).

7.5.2.3. Vapor Recovery Unit

A VRU captures vapors emitted during loading operations then routes them to VRU equipment to be absorbed and reintroduced into the process. The captured vapors are converted back into a liquid by using refrigeration, absorption, adsorption, and/or compression. Given the location of the proposed SPM buoy system, there is not a suitable location for the VRU equipment. A VRU would require a separate platform or the means for captured vapors to be routed back to an onshore VRU.

7.5.2.4. Vapor Combustion Unit

A VCU captures vapors emitted during loading operations and routes them to a combustion device for control. While this control method reduces the emissions of VOC, it creates collateral emissions increases of pollutants from combustion. Given the location of the proposed SPM buoy system, there is not a suitable location for the VCU equipment. A VCU would require a separate platform or the means for captured vapors to be routed back to an onshore VCU.

7.5.3. Elimination of Technically Infeasible Control Options

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

Based on this analysis of technical feasibility, VRU and VCU are both technically infeasible for application to the proposed SPM buoy system. Reasons for eliminating each option are identified below.

7.5.3.1. Vapor Combustion Unit

TGTI identified a VCU as a potential control technology because of its demonstrated ability to control emissions from land-based terminals. Though VCUs are demonstrated for land-based terminals, they have not been demonstrated as a control technology on sources similar to the proposed SPM buoy system. Application of VCU technology to the proposed SPM buoy system faces several inherent design challenges when compared to their application at land-based facilities, as identified below.

- Space Limitations
  - The proposed SPM buoy system is a single buoy floating roughly 14 miles offshore. The proposed SPM buoy system is not physically capable of housing equipment necessary for operation of a VCU. Modifications to the SPM buoy system to accommodate a VCU at the source is not a technically feasible option. Such modification would require the design and construction of a novel platform and vapor collection system that has not been demonstrated before. Such a platform would have to be located outside of the designated "swing circle" around the SPM buoy. The swing circle is the area around the SPM buoy in which the ship being loading is allowed to weathervane, or swing, around the SPM buoy during loading. This process is essential to the safety and design of the SPM buoy system as it allows the ship to optimally position itself around the SPM buoy to minimize the forces on the SPM buoy system. To allow for this movement pattern, a platform housing a VCU would have to be located safely outside of this circle, which is typically on the order of 1,500 to 2,000 ft in all directions. The vapor collection system would consist of a vapor collection line back to the SPM buoy, down to a subsea pipeline, then out to the VCU platform via this subsea pipeline. A vapor collection system of this manner has not been demonstrated in practice.

- Safety and Reliability Considerations Due to Variability in Operating Conditions
  - As described above, the vapor collection system that would be required for a VCU at the SPM buoy would be a new and unique system that is not currently in place at an SPM buoy system. The distance that the vapor collection line will have to travel underwater presents a reliability concern for the system. The long distance traversed by the vapor collection lines underwater increases the chances of condensed vapors in the vapor collection lines which would create both operational reliability and safety concerns. The other main concern is the constantly variable ocean conditions. Since the VCU equipment would have to be located on a floating platform, the natural motion of ocean waves will disturb the operation of the VCU and lead to unavoidable safety and reliability concerns.

Given the technical issues cited above VCU control technology is not an "applicable" technology to the proposed SPM buoy system since it cannot reasonably be installed and operated on the source type under consideration. Therefore VCU technology is eliminated from consideration as a technically infeasible control option.

7.5.3.2. Vapor Recovery Unit

TGTI identified a VRU as a potential control technology because of its demonstrated ability to control emissions from land-based terminals. Though VRUs are demonstrated for land-based terminals, they have not been demonstrated as a control technology on sources similar to the SPM buoy system. Application of VRU technology to the proposed SPM buoy system faces several design challenges when compared to their application at land-based facilities, as identified below.

- Space Limitations
  - The proposed SPM buoy system is a single buoy floating roughly 14 miles offshore. The proposed SPM buoy system is not physically capable of housing equipment necessary for operation of a VRU. Modifications to the SPM buoy system to accommodate a VRU at the source is not a technically feasible option. Such modification would require the design and construction of a novel platform and vapor collection system that has not been demonstrated before. Such a platform would have to be located outside of the designated "swing circle" around the SPM buoy. The swing circle is the area around the SPM buoy in which the ship being loading is allowed to weathervane, or swing, around the SPM buoy during loading. This process is essential to the safety and design of the SPM buoy system as it allows the ship to optimally position itself around the SPM buoy to minimize the forces on the SPM buoy system. To allow for this movement pattern, a platform housing a VRU would have to be located safely outside of this circle, which is typically on the order of 1,500 to 2,000 ft in all directions. The vapor collection system would consist of a vapor collection line back to the SPM buoy, down to a subsea pipeline, then out to the VRU platform via this subsea pipeline. A vapor collection system of this manner has not been demonstrated in practice.
- Safety and Reliability Considerations Due to Variability in Operating Conditions

- As described above, the vapor collection system that would be required for a VRU at the SPM buoy would be a new and unique system that is not currently in place at an SPM buoy system. The distance that the vapor collection line will have to travel underwater presents a reliability concern for the system. The long distance traversed by the vapor collection lines underwater increases the chances of condensed vapors in the vapor collection lines which would create both operational reliability and safety concerns. The other main concern is the constantly variable ocean conditions. Since the VRU equipment would have to be located on a floating platform, the natural motion of ocean waves will disturb the operation of the VRU and lead to unavoidable safety and reliability concerns. Traditional VRU control technology uses a tall absorber tower that, because of the height, will experience large oscillations at the tip, even from relatively small movement at the base from waves.

Given the technical issues cited above, VRU control technology is not an "applicable" technology to the proposed SPM buoy system since it cannot be reasonably be installed and operated on the source type under consideration. Therefore, traditional VRU technology is eliminated from consideration as a technically infeasible control option.

TGTI is aware of a technical report published on a spray absorption system that could theoretically be located on a floating platform and operate in spite of the influence of natural wave motions.[11] In this technical report, the concept of building a spray absorption VRU on a barge is theorized and a small-scale test was completed to demonstrate collection efficiency of the proposed design. The test described in the technical paper was completed at a flow rate of ~100x less than would be required for the proposed SPM buoy system. Additionally, the test was completed on fixed land, not a floating barge. Because of these reasons, the spray absorption VRU system on a barge is not considered technically available. Per the Manual there are several stages of bringing a control technology concept to reality as a commercial product that are as follows:

- Concept stage;
- Research and patenting;
- Bench scale or laboratory testing;
- Pilot scale testing;
- Licensing and commercial demonstration; and commercial sales.

The Manual states that a control technology is considered available if it has reached the licensing and commercial stages of development. The spray absorption VRU control system has only reached the bench scale or laboratory testing stage of development since it has only been demonstrated on a very small scale and on fixed land. The spray absorption VRU control technology is not technically available for application to the proposed SPM buoy system and is therefore not technically feasible.

[11] Yoshiki, Shibuya. "Vapor Recovery Technique for Crude Oil Ship Loading – Spray Absorption." JFE Technical Report No. 19. March 2014, p. 158-166.

7.5.4. Rank of Remaining Control Technologies

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies, ranked by effectiveness, are presented in the following table.

Table 7-1 – Rank of Remaining Control Technologies (VOC)

Rank	Control Technology	Expected Removal Efficiency
1	Submerged Loading	60%[12]
2	Work Practice Standards[13]	N/A

7.5.5. Evaluation of Most Stringent Control

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. Since submerged loading and only loading ships which have onboard and implement a VOC management plan that complies with the requirements of MEPC.185(59) are both being proposed as BACT, no further analysis is required.

7.5.6. Selection of BACT

Based on the previous analyses, TGTI has determined that submerged loading onto vessels which have onboard and implement a VOC management plan that complies with the requirements of MEPC.185(59) is BACT for the proposed SPM buoy system.

Table 7-2 – Summary of Proposed BACT (VOC)

Emission Unit	Pollutant	BACT Determination	Proposed BACT Emission Limit	Averaging Period
SPM Buoy System	VOC	Submerged Loading and loading ships which comply with VOC management plan requirements in MEPC.185(59)	N/A	N/A

[12] Reduction in emissions generated from loading compared to splash loading (75 FR 65115, Oct. 21, 2010).

[13] Work practice standards include a variety of VOC management principles that would be included in a VOC management plan required in MEPC.185(59).

8. AIR QUALITY MODELING AND OTHER IMPACT ANALYSES

While the NAAQS compliance demonstration and State Health Effects Review are being submitted under separate cover, the Additional Impacts Analysis is addressed below.

8.1. ADDITIONAL IMPACTS ANALYSIS

Due to the large distance of the Project's location from land areas, TGTI believes that the following impact analyses would not be applicable to the proposed project:

- Growth analysis
- Soils and vegetation analysis
- Visibility impairment analysis

Federal and TCEQ guidelines require that an air quality dispersion modeling analysis (including visibility analysis) be performed for each Class I area located within 100 km of a facility undergoing an installation/modification that exceeds PSD significant emission rates. Since the nearest Class I area is more than 500 km from the proposed SPM buoy system, a Class I area analysis is not required.

9. GENERAL APPLICATION REQUIREMENTS

This section discusses the state and federal air regulatory applicability for the SPM buoy system. The Deepwater Port Act of 1974 (DWPA) provides EPA authority to apply the CAA to activities associated with deepwater ports.[14] Per Section 1502(9)(D) of the DWPA a deepwater port is considered a new source for the purposes of the CAA(codified at 42 U.S.C. 7401 et seq.). Therefore, before a deepwater port may be constructed, the owner or operator must receive a new source review (NSR) permit from the EPA.

Additionally, 33 U.S.C. § 1518 (b) states that the law of the nearest adjacent coastal state is declared to be the law of the United States, and shall apply to any deepwater port licensed under the chapter. The nearest adjacent coastal state shall be the state whose seaward boundaries, if extended beyond 3 miles, would encompass the site of the deepwater port. Therefore, the laws of Texas are applicable to the proposed SPM buoy system. As such, in addition to an evaluation of the federal air regulatory applicability, this section also contains an evaluation of the Texas state air regulatory applicability.

In accordance with the DWPA and the provisions of Title I and Title V of the CAA, EPA will issue a new source review preconstruction permit. Though the federal operating permit program under 40 CFR 71 does not require a Title V application until 12 months after commencing operation, TGTI will prepare a Title V application to be submitted prior to operation of the proposed SPM buoy system. Since Texas is the "nearest adjacent coastal state, the Texas' EPA-approved SIP will be used to determine major NSR and Title V applicability. EPA however, will be the primary permitting authority.

CAA provision that are potentially applicable to the proposed SPM buoy system include the following:

- National Ambient Air Quality (NAAQS) regulations;
- Prevention of Significant Deterioration (PSD) regulations;
- New Source Performance Standards (NSPS);
- National Emission Standards for Hazardous Air Pollutants (NESHAP);
- Title V Operating Report;
- Compliance Assurance Monitoring (CAM);
- Risk Management Program (RMP); and
- Texas Commission on Environmental Quality (TCEQ) Regulations;

9.1. FEDERAL REGULATORY REQUIREMENTS

The proposed SPM buoy system will be located about 14 miles off the coast of Kleberg County, TX. Since the proposed location is located off the coast, it is not designated as attainment or nonattainment with respect to the EPA's NAAQS standards. While designation of the attainment status of the proposed location will be made on a case-by-case basis, it can be reasonably assumed given the closest designated areas are in attainment or unclassifiable for all pollutants, that the proposed location will be considered by EPA to be in attainment or unclassifiable as well. As such, the regulatory applicability analysis presented assumes the proposed location to be in attainment or unclassifiable with respect to the NAAQS standards.

[14] 33 CFR 148.3

9.1.1. Prevention of Significant Deterioration Regulations

A stationary source is considered "major" for PSD if it is located in an attainment/unclassifiable area and has the potential to emit either (1) 100 tpy or more of a regulated pollutant if the source is classifies as one of the 28 designated industrial source categories, or (2) 250 tpy or more of any regulated pollutant for unlisted sources. The proposed SPM buoy system is not considered a PSD listed source and, therefore, the PSD review threshold is 250 tpy for criteria pollutants.

The proposed SPM buoy system will trigger PSD major source thresholds due to being located in an attainment/unclassifiable area and to VOC emissions exceeding 250 tpy. Once this threshold has been exceeded, emissions of each criteria pollutant are compared against the respective PSD significant emission rate (SER), and emissions of GHGs are compared against the GHG PSD threshold to determine if the project triggers PSD review for other pollutants. Per TCEQ guidance, only emissions from the marine loading operations have been considered in the applicability determination comparison against the PSD major source thresholds. Emissions from the vessel and other ancillary operations have been considered secondary emissions and are not included in the PSD applicability determination.[15] Based on the comparisons, the proposed SPM buoy system will be a major source under PSD for VOCs only.

9.1.2. Nonattainment New Source Review

Nonattainment New Source Review (NNSR) will not apply to the proposed SPM buoy system because the proposed location will be classified as in attainment or unclassifiable for all relevant NAAQS.

9.1.3. New Source Performance Standards

TGTI reviewed each NSPS and found no NSPS regulations that are potentially applicable to the proposed SPM buoy system.

9.1.4. National Emission Standards for Hazardous Air Pollutants

The proposed SPM buoy system will be a major source of HAP as potential emissions are above the HAP major source threshold (potential emissions of HAP are 200 tpy). The proposed SPM buoy system will not be subject to any NESHAP subpart in 40 CFR Part 61.

NESHAP Subpart Y applies to affected sources of Marine Tank Vessel Loading Operations. The following definitions from NESHAP Subpart Y (40 CFR 63.561) are important provisions used to determine what qualifies as an affected source regulated under NESHAP Subpart Y.

> ***Affected source*** *means a source with emissions of 10 or 25 tons, a new major source with emissions less than 10 and 25 tons, a new major source offshore loading terminal, a source with throughput of 10 M barrels or 200 M barrels, or the VMT source, that is subject to the emission standards in §63.562.*
>
> ***Source(s)*** *means any location where at least* ***one dock or loading berth*** *is bulk loading onto marine tank vessels, except offshore drilling platforms and lightering operations.*

[15] TCEQ APDG 5881, June 2017

Offshore Loading Terminal *means a location that has at least* ***one loading berth*** *that is 0.81 km (0.5 miles) or more from the shore that is used for mooring a marine tank vessel and loading liquids from shore."*

Loading berth *means the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill marine tank vessels. The loading berth includes those items necessary for an offshore loading terminal.*

The proposed SPM buoy system does not fit the definition of a "loading berth" per the definition set forth in 40 CFR 63.561 since the proposed SPM buoy system will not have loading arms, pumps, meters, shutoff valves, nor relief valves. Additionally, the proposed SPM buoy system does not have a "dock" or any fixed structure resembling a dock structure. Per the Cambridge Dictionary, a dock is defined as "a structure built out over the water in a port along which ships can land to load and unload, or the enclosed area of water between two such structures."

Therefore the proposed SPM buoy system does not fit the definition of an "affected source" because it does not meet the definition of a "source" as stated in 40 CFR 63.561.

The definitions of "offshore loading terminal" and "loading berth" are essentially circular. Therefore, TGTI also reviewed the NESHAP Subpart Y preamble and technological support documents to determine if there were any sources similar to the proposed SPM buoy system that were considered in the rulemaking. Based on this review, TGTI concluded that there were no similar sources to the proposed SPM buoy system (i.e., SPM buoy systems for directly and completely loading a VLCC for crude oil export) considered in the development of the NESHAP Subpart Y regulations. The proposed SPM buoy system will be a first of its kind for the United States. Export of crude oil was banned in the United States from 1975, following the 1973 OPEC oil embargo, until 2015 to all countries except Canada. Therefore, because of this legal restriction, there could not have been similar sources in operation when NESHAP Subpart Y was developed in 1995 nor when it was reconsidered in 2011.

The proposed SPM buoy system also presents unique technical, environmental, and operational concerns compared to the sources that were considered in the establishment of MACT Subpart Y standards. EPA acknowledged in responses to comments on the 1995 NESHAP Subpart Y rule that the subcategory established for "offshore terminals" could be broken down into additional subcategories based on throughputs, products handled, etc. It did not, however, consider doing so in 1995 because the public comments did not justify additional subcategories. This reinforces TGTI's conclusion that the proposed SPM buoy system is not an affected source under NESHAP Subpart Y.

The proposed SPM buoy system represents a major source of HAP emissions that is not specifically regulated or exempted from regulation under a standard issued pursuant to section 112(d), section 112(h) or section 112(j) and incorporated in another subpart of part 63 the requirements of 40 CFR 63.40 through 63.44 apply.[16] The regulations contained in 40 CFR 63.40 through 63.44 carry out section 112(g)(2)(B) of the CAA as it relates to a Case-by-Case MACT determination. As such, TGTI has prepared a Case-by-Case MACT determination application in accordance with 40 CFR 63.40 through 63.44 and Section 112(g) of the CAA to demonstrate the proposed control requirements of submerged fill is the maximum achievable control technology for the proposed SPM buoy system. The Case-by-Case MACT application is submitted under separate cover.

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[16] 40 CFR 63.40

9.1.5. Title V Operating Permits

40 CFR Parts 70 and 71 require operating permits for major sources of criteria pollutants. Since potential emissions of VOC will exceed the Title V major source threshold of 100 tpy and emissions of HAP exceed the Title V major source threshold of 10 tpy of a single HAP or 25 tpy of aggregate HAP, a Title V permit will be required. Per EPA Regions 6 request, TGTI is including a Title V permit application along with the submittal of the PSD preconstruction permit application. The applicable Part 71 forms have been provided for the Title V application under separate cover.

9.1.6. Compliance Assurance Monitoring

CAM is applicable to certain sources which use add-on control devices to achieve compliance. Since the proposed SPM buoy system will not utilize any add-on control devices, CAM is not applicable.

9.1.7. Title IV Acid Rain Provisions

The proposed SPM buoy system will not operate any units are affected under the Acid Rain Program.

9.1.8. Risk Management Program, Section 112(r)

The proposed SPM buoy system will not store any substances regulated under the RPM.

9.2. STATE REGULATORY REQUIREMENTS

9.2.1. General Application Requirements (30 TAC §116.111)

(1) a completed Form PI-1 General Application signed by an authorized representative of the applicant. All additional support information specified on the form must be provided before the application is complete;

A completed TCEQ Form PI-1 signed by an authorized representative and all additional supporting information as specified on the form are provided in this application.

(2) information which demonstrates that emissions from the facility, including any associated dockside vessel emissions, meet all of the following.

(2)(A) Protection of public health and welfare.

(2)(A)(i) The emissions from the proposed facility will comply with all rules and regulations of the commission and with the intent of the Texas Clean Air Act (TCAA), including protection of the health and property of the public.

TGTI will comply with all rule and regulations of the commission and with the intent of the Texas Clean Air Act (TCAA), including protection of the health and property of the public. A review of potentially applicable rules is provided below.

Chapter 101 – General Rules: The proposed SPM buoy system will be operated in accordance with all applicable requirements in Chapter 101. Specifically, the proposed SPM buoy system will be operated in accordance with the Chapter 101 General Rules relating to circumvention, nuisance, traffic hazard, notification and recordkeeping requirements for emission events and for startup/shutdown/maintenance, sampling and sampling port procedures, emissions inventory requirements, compliance with Environmental Protection Agency Standards, the National Primary and Secondary Ambient Air Quality Standards, inspection fees, emissions fees, and all other applicable General Rules.

Chapter 111 - Control of Air Pollution from Visible Emissions and Particulate Matter: The proposed SPM buoy system will comply with all applicable requirements in Chapter 111.

Chapter 112 – Control of Air Pollution from Sulfur Compounds: The proposed SPM buoy system will comply with all applicable emission limitations, allowable emission rates, monitoring, reporting, and recordkeeping requirements of 30 TAC Chapter 112.

Chapter 113 – Control of Air Pollution from Toxic Materials: Chapter 113 regulates the emission of radionuclides (40 CFR Part 61, Subpart R), municipal solid waste landfills, hospital/medical/infectious waste incinerators, and hazardous air pollutants for source categories (40 CFR Part 63). There will be no emissions of radionuclides from the proposed SPM buoy system. The proposed SPM buoy system is not a municipal solid waste landfill and does not have a hospital/medical/ infectious waste incinerator. Therefore, these sections of the regulation do not apply. Emissions from hazardous air pollutants are regulated under the MACT program, addressed in the discussion of compliance with Chapter 122 in item (2)(F) below.

Chapter 114 – Control of Air Pollution from Motor Vehicles: No motor vehicles will operate at the proposed SPM buoy system. Therefore, the provisions of Chapter 114 do not apply.

Chapter 115 – Control of Air Pollution from Volatile Organic Compounds (VOC): The proposed SPM buoy system will comply with all applicable requirements in Chapter 115 for loading operations.

Chapter 117 – Control of Air Pollution from Nitrogen Compounds: The proposed SPM buoy system will not be located in a county that is subject to the requirements of Chapter 117.

Chapter 118 – Control of Air Pollution Episodes: The proposed SPM buoy system will not be located in a county that is subject to the requirements of Chapter 118.

Chapter 122 – Federal Operating Permits: The proposed SPM buoy system will be a major source of regulated pollutants as defined in 30 TAC Chapter 122. TGTI will submit a Title V Permit application per the requirements of 40 CFR Part 71 per EPA Region 6 request.

(2)(B) Measurement of emissions. The proposed facility will have provisions for measuring the emission of significant air contaminants as determined by the executive director. This may include the installation of sampling ports on exhaust stacks and construction of sampling platforms in accordance with guidelines in the "Texas Commission on Environmental Quality Sampling Procedures Manual."

Emissions from any source addressed in the application will be sampled upon request of the Executive Director of the TCEQ, and sampling ports and sampling platforms will be installed as needed.

(2)(C) Best available control technology (BACT) must be evaluated for and applied to all facilities subject to the TCAA. Prior to evaluation of BACT under the TCAA, all facilities with pollutants subject to regulation under Title I Part C of the Federal Clean Air Act (FCAA) shall evaluate and apply BACT as defined in §116.160(c)(1)(A) of this title (relating to Prevention of Significant Deterioration Requirements).

This permit application demonstrates that the proposed SPM buoy system will utilize BACT for all emissions sources being proposed as part of this permit application.

(2)(D) New Source Performance Standards (NSPS). The emissions from the proposed facility will meet the requirements of any applicable NSPS as listed under 40 Code of Federal Regulations (CFR) Part 60, promulgated by the United States Environmental Protection Agency (EPA) under FCAA, §111, as amended.

The proposed SPM buoy system will not be subject to any NSPS under 40 CFR Part 60.

(2)(E) National Emission Standards for Hazardous Air Pollutants (NESHAP). The emissions from the proposed facility will meet the requirements of any applicable NESHAP, as listed under 40 CFR Part 61, promulgated by EPA under FCAA, §112, as amended.

The proposed SPM buoy system will not be subject to NESHAPs under 40 CFR Parts 61.

(2)(F) NESHAP for source categories. The emissions from the proposed facility will meet the requirements of any applicable maximum achievable control technology standard as listed under 40 CFR Part 63, promulgated by the EPA under FCAA, §112 or as listed under Chapter 113, Subchapter C of this title (relating to National Emissions Standards for Hazardous Air Pollutants for Source Categories (FCAA §112, 40 CFR Part 63)).

The proposed SPM buoy system is potentially subject to NESHAPs under 40 CFR Parts 63 but was determined to not be subject to NESHAP Subpart Y. TGTI has included a case-by-case MACT applicability assessment to demonstrate that the maximum achievable control technology is being applied to the proposed SPM buoy system.

(2)(G) Performance demonstration. The proposed facility will achieve the performance specified in the permit application. The applicant may be required to submit additional engineering data after a permit has been issued in order to demonstrate further that the proposed facility will achieve the performance specified in the permit application. In addition, dispersion modeling, monitoring, or stack testing may be required.

The proposed SPM buoy system will achieve the performance represented in this permit application.

(2)(H) Nonattainment review. If the proposed facility is located in a nonattainment area, it shall comply with all applicable requirements in this chapter concerning nonattainment review.

As discussed earlier in this section, the proposed SPM buoy system is not located in a nonattainment county, NNSR is not applicable.

(2)(I) Prevention of Significant Deterioration (PSD) review.
(2)(I)(i) If the proposed facility is located in an attainment area, it shall comply with all applicable requirements in this chapter concerning PSD review.

(2)(I)(ii) If the proposed facility or modification meets or exceeds the applicable greenhouse gases thresholds defined in §116.164 of this title (relating to Prevention of Significant Deterioration Applicability for Greenhouse Gases Sources) then it shall comply with all applicable requirements in this chapter concerning PSD review for sources of greenhouse gases.

The proposed SPM buoy system is a new major source with respect to the PSD permitting program due to potential emissions of VOCs; therefore, TGTI is submitting this application in order to comply with the PSD new source review requirements in this chapter.

(2)(J) Air dispersion modeling. Computerized air dispersion modeling may be required by the executive director to determine air quality impacts from a proposed new facility or source modification. In determining whether to issue, or in conducting a review of, a permit application for a shipbuilding or ship repair operation, the commission will not require and may not consider air dispersion modeling results predicting ambient concentrations of non-criteria air contaminants over coastal waters of the state. The commission shall determine compliance with non-criteria ambient air contaminant standards and guidelines at land-based off-property locations.

TGTI has conducted air dispersion modeling to demonstrate the ambient air impacts of the proposed SPM buoy system. They have been submitted under separate cover.

(2)(K) Hazardous air pollutants. Affected sources (as defined in §116.15(1) of this title (relating to Section 112(g) Definitions)) for hazardous air pollutants shall comply with all applicable requirements under Subchapter E of this chapter (relating to Hazardous Air Pollutants: Regulations Governing Constructed or Reconstructed Major Sources (FCAA, §112(g), 40 CFR Part 63)).

TGTI will comply will comply with all applicable requirements under Subchapter E of this chapter as related to Section 112(g).

(2)(L) Mass cap and trade allowances. If subject to Chapter 101, Subchapter H, Division 3, of this title (relating to Mass Emissions Cap and Trade Program), the proposed facility, group of facilities, or account must obtain allowances to operate.

This regulation refers to Chapter 101, Subchapter H, Division 3, which applies to facilities in the Houston-Galveston-Brazoria (HGB) ozone nonattainment area. The proposed SPM buoy system will not located in the HGB ozone nonattainment area. Therefore, the provisions of this regulation do not apply.

(b) In order to be granted a permit, amendment, or special permit amendment, the owner or operator must comply with the following notice requirements.

(1) Applications declared administratively complete before September 1, 1999, are subject to the requirements of Division 3 of this subchapter (relating to Public Notification and Comment Procedures).

Not applicable. The permit application will be sent to the TCEQ in 2018.

(2) Applications declared administratively complete on or after September 1, 1999, are subject to the requirements of Chapter 39 of this title (relating to Public Notice) and Chapter 55 of this title (relating to Request for Reconsideration and Contested Case Hearings; Public Comment). Upon request by the owner or operator of a facility which previously has received a permit or special permit from the commission, the executive director or designated representative may exempt the relocation of such facility from the provisions in Chapter 39 of this title if there is no indication that the operation of the facility at the proposed new location will significantly affect ambient

air quality and no indication that operation of the facility at the proposed new location will cause a condition of air pollution.

TGTI will comply with all applicable notice requirements under Chapter 39 and Chapter 55 associated with this permit application.

10. PERMIT FEE AND PROFESSIONAL ENGINEER CERTIFICATION

Per 30 TAC §116.110(f), since the project's capital cost is greater than $2,000,000, a professional engineer review has been completed and a certification is included.

Per guidance from EPA Region 6, there is no fee associated with a PSD permit application. TGTI has included the TCEQ form and has indicated no fee is required for completeness.

Texas Commission on Environmental Quality
Table 30
Estimated Capital Cost and Fee Verification

I certify that the total estimated capital cost of the project as defined in 30 TAC § 116.141 is equal to or less than the above figure. I further state that I have read and understand Texas Water Code § 7.179, which defines Criminal Offenses for certain violations, including intentionally or knowingly making, or causing to be made, false material statements or representations.

Company Name: Texas Gulf Terminals Inc.

Company Representative Name *(please print)*: Denise Rogers

Title: Regulatory Compliance Manager

Company Representative Signature: Denise Rogers

Estimated Capital Cost		Permit Application Fee	GHG*/PSD/Nonattainment Application Fee
Less than	$300,000	$900 (minimum fee)	$3,000 (minimum fee)
$300,000 to	$25,000,000	0.30% of capital cost	
$300,000 to	$7,500,000		1.0% of capital cost
Greater than	$25,000,000	$75,000 (maximum fee)	
Greater than	$7,500,000		$75,000 (maximum fee)

*A single PSD fee (calculated on the capital cost of the project per 30 TAC § 116.163) will be required for all of the associated permitting actions for a GHG PSD project. Other NSR permit fees related to the project that have already been remitted to the TCEQ can be subtracted when determining the appropriate fee to submit with the GHG PSD application; please identify these other fees in the GHG PSD permit application.

Permit Application Fee (from table above) = $0 (See Application Narrative) Date: 6/26/2018

10.2. PROFESSIONAL ENGINEER CERTIFICATION

I directly supervised the engineering work products contained in the Emissions Calculations section and Appendix A and the Federal BACT section.

To the best of my knowledge, the representations made in this document are true and accurate. By affixing my seal below, I submit that the engineering work and calculations performed in the above listed sections were either performed by myself or under my direct supervision, as defined in Section 131.18 of the Texas Engineering Practice Act and in compliance with Title 30 of the Texas Administrative Code, Chapter 116, Section 116.110(f).

PROFESSIONAL ENGINEER CERTIFICATION

Based on the information provided by TGTI, I directly supervised the engineering work products contained in the following sections of this document.

Emissions Calculations

Best Available Control Technology

To the best of my knowledge, the representations made in this document are true and accurate. By affixing my seal below, I submit that the engineering work and calculations performed in the above listed sections were either performed by myself or under my direct supervision, as defined in Section 131.18 of the Texas Engineering Practice Act and incompliance with Title 30 of the Texas Administrative Code, Chapter 116, Section 116.110(f).

Place P.E. Seal below this line

Signature

June 26, 2018

Date

STATE OF TEXAS
HUNG-MING SUNG
83530
LICENSED
PROFESSIONAL ENGINEER

Name: Hung-Ming Sung, Trinity Consultants

APPENDIX A: EMISSION CALCULATIONS

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Marine Loading (DWP Emissions Source for PSD Applicability)
Criteria Pollutants

Hourly and Annual VOC Emissions Estimates for Loading of Crude Oil and Condensate

Hourly Loading Emissions

Liquid Loaded [1]	Saturation Factor [2]	Maximum Temp [3] (˚F)	Maximum Temp [3] (˚R)	Vapor MW (lb/lb mol)	Maximum True Vapor Pressure (TVP) [4] (psia)	Arrival Emission Factor [5] (lb/1,000 gal)	Generated Emission Factor [6] (lb/1,000 gal)	Uncontrolled Loading Loss [7] (lb/1,000 gal)	TOC to VOC Factor	Hourly Loading Rate [8] (bbl/hr)	Uncontrolled VOC Hourly Emissions [9] (lb/hr)
Crude Oil	0.2	73.50	533.17	50	11.00	--	--	2.57	1.00	60,000	6,478.07
Condensate	0.2	73.50	533.17	60	11.00	--	--	3.08	1.00	60,000	7,773.68

[1] For hourly emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.

[2] Saturation factor for marine loading obtained from U.S. EPA 42, Section 5.2 (1/95), Table 5.2-1.

[3] Maximum of monthly average liquid surface temperature was used .

[4] Maximum true vapor pressure for Crude oil and Condensate obtained from information provided by Texas Gulf Terminals

[5] Arrival emission factor for crude/condensate loading obtained from U.S. EPA 42, Section 5.2 (1/95), Table 5.2-3.

[6] Generated emission factor is calculated using equation 3 from U.S. EPA 42, Section 5.2 (1/95).

[7] Uncontrolled Loading Loss (lb/1,000 gal) = 12.46 x Saturation Factor x Maximum TVP of Liquid Loaded (psia) x Vapor MW (lb/lbmol) / Maximum Temperature of Bulk Liquid Loaded (^{o}R)

$$\text{Crude Oil Uncontrolled Loading Loss (lb/1,000 gal)} = \frac{12.46 \;\vert\; 0.2 \;\vert\; 11.00\text{ psia} \;\vert\; 50\text{ lb}}{\text{lbmole}} \;\vert\; \frac{1}{533.17\text{ R}} = 2.57\text{ lb/1,000 gal}$$

[8] Hourly Loading Rate obtained from information provided by TGTI Revised Design Parameters email from Ms. Denise Rogers (TGTI) to Mr. Brian Burdorf (Trinity Consultants) on February 25, 2018.

[9] Uncontrolled VOC Hourly Emissions (lb/hr) = Uncontrolled Loading Loss (lb/1,000 gal) x Hourly Loading Rate (bbl/hr) x 42 gal/bbl x TOC to VOC Factor x (1/1,000)

$$\text{Crude Oil Uncontrolled Loading Emissions (lb/hr)} = \frac{2.57\text{ lb}}{1{,}000\text{ gal}} \;\vert\; \frac{60{,}000\text{ bbl}}{\text{hr}} \;\vert\; \frac{42\text{ gal}}{\text{bbl}} \;\vert\; 1.00 \;\vert\; \frac{1}{1{,}000} = 6{,}478\text{ lb/hr}$$

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Marine Loading (DWP Emissions Source for PSD Applicability)
Criteria Pollutants

Annual Loading Emissions

Liquid Loaded [1]	Saturation Factor [2]	Annual Average Temp [3]		Vapor MW	Average True Vapor Pressure (TVP) [4]	Arrival Emission Factor [5]	Generated Emission Factor [6]	Uncontrolled Loading Loss [7]	TOC to VOC Factor	Annual Loading Rate [8]	Uncontrolled VOC Annual Emissions [9]
		(˚F)	(˚R)	(lb/lb mol)	(psia)	(lb/1,000 gal)	(lb/1,000 gal)	(lb/1,000 gal)		(bbl/yr)	(tpy)
Crude Oil	0.2	73.50	533.17	50	11.00	--	--	2.57	1.00	192,000,000	10,364.91
Condensate	0.2	73.50	533.17	62	9.25	--	--	2.68	1.00	192,000,000	10,807.77

[1] For annual emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.

[2] Saturation factor for marine loading obtained from U.S. EPA 42, Section 5.2 (1/95), Table 5.2-1.

[3] Average of monthly average liquid surface temperature was used .

[4] Average true vapor pressure for Crude oil and Condensate obtained from information provided by Texas Gulf Terminals

[5] Arrival emission factor for crude/condensate loading obtained from U.S. EPA 42, Section 5.2 (1/95), Table 5.2-3.

[6] Generated emission factor is calculated using equation 3 from U.S. EPA 42, Section 5.2 (1/95).

[7] Uncontrolled Loading Loss (lb/1,000 gal) = 12.46 x Saturation Factor x Average TVP of Liquid Loaded (psia) x Vapor MW (lb/lbmol) / Average Temperature of Bulk Liquid Loaded (^oR)

Crude Oil Uncontrolled Loading Loss (lb/1,000 gal) = 12.46 × 0.2 × 11.00 psia × (50 lb / lbmole) × (1 / 533.17 R) = 2.57 lb/1,000 gal

[8] Annual Loading Rate obtained from information provided by TGTI Revised Design Parameters email from Ms. Denise Rogers (TGTI) to Mr. Brian Burdorf (Trinity Consultants) on February 25, 2018 and June 22, 2018.

[9] Uncontrolled VOC Loading Emissions (tpy) = Uncontrolled Loading Loss (lb/1,000 gal) x Annual Loading Rate (bbl/yr) x 42 gal/bbl x TOC to VOC Factor x (1/1,000) x (1 ton/2,000 lb)

Crude Oil Uncontrolled Loading Emissions (tpy) = (2.57 lb / 1,000 gal) × (192,000,000 bbl / yr) × (42 gal / bbl) × 1.00 × (1 / 1,000) × (1 ton / 2,000 lb) = 10,365 tpy

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Marine Loading (DWP Emissions Source for PSD Applicability)
Criteria Pollutants

Hourly and Annual H_2S Emissions Estimates for Loading of Crude Oil and Condensate

Parameter	Value	Unit
H_2S MW	34.1	lb/lbmol
H_2S Max Vapor Fraction in Crude oil [1]	2.40E-05	
H_2S Max Vapor Fraction in Condensate [1]	2.40E-05	
Maximum Mass Ratio of H_2S in Crude Oil [2]	2.19E-05	lb H_2S/lb VOC
Maximum Mass Ratio of H_2S in Condensate [2]	1.76E-05	lb H_2S/lb VOC

[1] Maximum H_2S vapor fraction is assumed to be 24 ppmv for sweet crude.
[2] H_2S Mass Ratio in Crude Oil/Condensate (lb H_2S/lb VOC) = H_2S Vapor Fraction in Crude Oil/Condensate x H_2S MW (lb/lbmole)/Crude Oil/Condensate Vapor MW (lb/lbmole) x 14.7 psia/Vapor Pressure of Crude Oil/Condensate (psia)

$$\text{Max } H_2S \text{ Mass Ratio in Crude Oil (lb } H_2S\text{/lb VOC)} = \frac{2.40\text{E-05}}{} \cdot \frac{34.1 \text{ lb}}{\text{lbmole}} \cdot \frac{\text{lbmole}}{50 \text{ lb}} \cdot \frac{14.7 \text{ psia}}{11 \text{ psia}} = 2.19\text{E-05 lb H2S/lb VOC}$$

Liquid Loaded [1]	Maximum TVP [2] (psia)	Uncontrolled VOC Hourly Emissions (lb/hr)	Uncontrolled VOC Annual Emissions (tpy)	H_2S Hourly Emissions [3] (lb/hr)	H_2S Annual Emissions [4] (tpy)
Crude Oil	11.00	6,478	10,365	0.14	0.23
Condensate	11.00	7,774	10,808	0.17	0.24

[1] For hourly and annual emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.
[2] Maximum true vapor pressure for Crude oil and Condensate obtained from information provided by Texas Gulf Terminals
[3] H_2S Hourly Emissions (lb/hr) = Max H_2S Mass Ratio in Crude/Condensate (lb H_2S/lb VOC) x Uncontrolled VOC Hourly Emissions (lb/hr)

$$H_2S \text{ Hourly Emissions from Crude Oil (lb/hr)} = \frac{2.19\text{E-05 lb H2S}}{\text{lb VOC}} \cdot \frac{7{,}774 \text{ lb}}{\text{hr}} = 0.14 \text{ lb/hr}$$

[4] H_2S Annual Emissions (tpy) = Max H_2S Mass Ratio in Crude/Condensate (lb H_2S/lb VOC) x Uncontrolled VOC Annual Emissions (tpy)

$$H_2S \text{ Annual Emissions from Crude Oil (tpy)} = \frac{2.19\text{E-05 lb H2S}}{\text{lb VOC}} \cdot \frac{10{,}808 \text{ tpy}}{} = 0.23 \text{ tpy}$$

APPENDIX B: FEDERAL NSR ANALYSIS TCEQ TABLES

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: N/A	Application Submittal Date:
Company: Texas Gulf Terminals Inc	
RN: 110317666	Facility Location:
City:	County:
Permit Unit I.D.:	Permit Name:
Permit Activity: ☒ New Source ☐ Modification	

Complete for all Pollutants with a Project Emission Increase.	**POLLUTANTS**							
	Ozone							
	VOC	**NO_x**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**NO_X**	**SO_2**	**Other[1]**
Nonattainment?								
PSD?	X							
Existing site PTE (tpy)?								
Proposed project emission increases (tpy from 2F[2])?								
Is the existing site a major source?								
If not, is the project a major source by itself?								
If site is major source, is project increase significant?								
If netting required, estimated start of construction:								
5 years prior to start of construction								contemporaneous
Estimated start of operation								period
Net contemporaneous change, including proposed project, from Table 3F. (tpy)								
Major NSR Applicable?								

Denise Rogers	Compliance Mgr.	10/26/2018
Signature	***Title***	***Date***

[1] Other pollutants. [Pb, H_2S, TRS, H_2SO_4, Fluoride excluding HF, etc.]

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

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

APPENDIX C: MEPC.185(59) – GUIDANCE FOR VOC MANAGEMENT PLANS

ANNEX 10

RESOLUTION MEPC.185(59)
Adopted on 17 July 2009

GUIDELINES FOR THE DEVELOPMENT OF A VOC MANAGEMENT PLAN

THE MARINE ENVIRONMENT PROTECTION COMMITTEE,

RECALLING Article 38(a) of the Convention on the International Maritime Organization concerning the functions of the Marine Environment Protection Committee conferred upon it by international conventions for the prevention and control of marine pollution,

NOTING that the revised MARPOL Annex VI was adopted by resolution MEPC.176(58) which is expected to enter into force on 1 July 2010,

NOTING ALSO that regulation 15.6 of the revised Annex VI requires a tanker carrying crude oil to have onboard and implement a VOC management plan approved by the Administration, and that such a plan shall be prepared taking into account the guidelines developed by the Organization,

HAVING CONSIDERED the draft Guidelines for the development of a VOC management plan prepared by the Sub-Committee on Bulk Liquids and Gases at its thirteenth session,

1. ADOPTS the Guidelines for the development of a VOC management plan, as set out in the Annex to this resolution; and

2. INVITES Governments to apply the Guidelines from 1 July 2010.

ANNEX

GUIDELINES FOR THE DEVELOPMENT OF A VOC MANAGEMENT PLAN

1 Objectives

.1 The purpose of the VOC management plan is to ensure that the operation of a tanker, to which regulation 15 of MARPOL Annex VI applies, prevents or minimizes VOC emissions to the extent possible.

.2 Emissions of VOCs can be prevented or minimized by:

.1 optimizing operational procedures to minimize the release of VOC emissions; and/or

.2 using devices, equipment, or design changes to prevent or minimize VOC emissions.

.3 To comply with this plan, the loading and carriage of cargoes which generate VOC emissions should be evaluated and procedures written to ensure that the operations of a ship follow best management practices for preventing or minimizing VOC emissions to the extent possible. If devices, equipment, or design changes are implemented to prevent or minimize VOC emissions, they shall also be incorporated and described in the VOC management plan as appropriate.

.4 While maintaining the safety of the ship, the VOC management plan should encourage and, as appropriate, set forth the following best management practices:

.1 the loading procedures should take into account potential gas releases due to low pressure and, where possible, the routing of oil from crude oil manifolds into the tanks should be done so as to avoid or minimize excessive throttling and high flow velocity in pipes;

.2 the ship should define a target operating pressure for the cargo tanks. This pressure should be as high as safely possible and the ship should aim to maintain tanks at this level during the loading and carriage of relevant cargo;

.3 when venting to reduce tank pressure is required, the decrease in the pressure in the tanks should be as small as possible to maintain the tank pressure as high as possible;

.4 the amount of inert gas added should be minimized. Increasing tank pressure by adding inert gas does not prevent VOC release but it may increase venting and therefore increased VOC emissions; and

.5 when crude oil washing is considered, its effect on VOC emissions should be taken into account. VOC emissions can be reduced by shortening the duration of the washing or by using a closed cycle crude oil washing programme.

2 Additional considerations

.1 A person in charge of carrying out the plan

.1 A person shall be designated in the VOC management plan to be responsible for implementing the plan and that person may assign appropriate personnel to carry out the relevant tasks;

.2 Procedures for preventing or minimizing VOC emissions

.1 Ship-specific procedures should be written or modified to address relevant VOC emissions, such as the following operations:

.1 Loading;

.2 Carriage of relevant cargo; and

.3 Crude oil washing;

.2 If the ship is equipped with VOC reduction devices or equipment, the use of these devices or equipment should be incorporated into the above procedures as appropriate.

.3 Training

.1 The plan should describe the training programmes to facilitate best management practices for the ship to prevent or minimize VOC emissions.

***

APPENDIX D: MEPC.1/CIRC.680

INTERNATIONAL MARITIME ORGANIZATION
4 ALBERT EMBANKMENT
LONDON SE1 7SR

Telephone: 020 7735 7611
Fax: 020 7587 3210

IMO

E

Ref. T5/1.01

MEPC.1/Circ.680
27 July 2009

TECHNICAL INFORMATION ON SYSTEMS AND OPERATION TO ASSIST DEVELOPMENT OF VOC MANAGEMENT PLANS

1 The Marine Environment Protection Committee, at its fifty-ninth session (13 to 17 July 2009), approved the Guidelines for the Development of a Volatile Organic Compound (VOC) Management Plan for tankers carrying crude oil (resolution MEPC.185(59)).

2 In conjunction with consideration of the guidelines, MEPC 59 agreed that additional technical information on vapour pressure control systems and their operation would assist the industry in development of VOC management plans. Therefore, MEPC 59 agreed to the technical information on systems and operation to assist development of VOC management plans for tankers carrying crude oil, as set out in the annex to this document.

3 The technical information addresses the general equipment and systems involved, their operation and conditions on board a crude oil tanker with respect to the formation and emission of Volatile Organic Compounds (VOC) as well as the ability to control VOC formation and emissions.

4 Member Governments are invited to bring this circular to the attention of their Administrations, relevant shipping organizations, recognized organizations, shipping companies and other stakeholders concerned and encourage them to take it into account when applying the Guidelines for the development of a VOC management plan for crude oil tankers.

***

ANNEX

TECHNICAL INFORMATION ON VAPOUR PRESSURE CONTROL SYSTEMS AND THEIR OPERATION TO ASSIST DEVELOPMENT OF VOC MANAGEMENT PLANS FOR TANKERS CARRYING CRUDE OIL

Introduction

This technical information is compiled pursuant to the requirements in MARPOL Annex VI Regulation 15.6, and describes the general equipment, operations and conditions onboard a crude oil tanker with respect to the emission and ability to control Volatile Organic Compound (VOC) emissions.

The Guidelines for the development of a VOC management plan state:

1 Objectives

.1 The purpose of the VOC management plan is to ensure that the operation of a tanker, to which regulation 15 of MARPOL Annex VI applies, prevents or minimizes VOC emissions to the extent possible.

.2 Emissions of VOCs can be prevented or minimized by:

.1 optimizing operational procedures to minimize the release of VOC emissions; and/or

.2 using devices, equipment, or design changes to prevent or minimize VOC emissions.

.3 To comply with this plan, the loading and carriage of cargoes which generate VOC emissions should be evaluated and procedures written to ensure that the operations of a ship follow best management practices for preventing or minimizing VOC emissions to the extent possible. If devices, equipment, or design changes are implemented to prevent or minimize VOC emissions, they shall also be incorporated and described in the VOC management plan as appropriate.

.4 While maintaining the safety of the ship, the VOC management plan should encourage and, as appropriate, set forth the following best management practices:

.1 the loading procedures should take into account potential gas releases due to low pressure and, where possible, the routing of oil from crude oil manifolds into the tanks should be done so as to avoid or minimize excessive throttling and high flow velocity in pipes;

.2 the ship should define a target operating pressure for the cargo tanks. This pressure should be as high as safely possible and the ship should aim to maintain tanks at this level during the loading and carriage of relevant cargo;

.3 when venting to reduce tank pressure is required, the decrease in the pressure in the tanks should be as small as possible to maintain the tank pressure as high as possible;

.4 the amount of inert gas added should be minimized. Increasing tank pressure by adding inert gas does not prevent VOC release but it may increase venting and therefore increased VOC emissions; and

.5 when crude oil washing is considered, its effect on VOC emissions should be taken into account. VOC emissions can be reduced by shortening the duration of the washing or by using a closed cycle crude oil washing programme.

2 Additional considerations

.1 A person in charge of carrying out the plan

.1 A person shall be designated in the VOC management plan to be responsible for implementing the plan and that person may assign appropriate personnel to carry out the relevant tasks;

.2 Procedures for preventing or minimizing VOC emissions

.1 Ship-specific procedures should be written or modified to address relevant VOC emissions, such as the following operations:

.1 Loading;

.2 Carriage of relevant cargo; and

.3 Crude oil washing;

.2 If the ship is equipped with VOC reduction devices or equipment, the use of these devices or equipment should be incorporated into the above procedures as appropriate.

.3 Training

.1 The plan should describe the training programmes to facilitate best management practices for the ship to prevent or minimize VOC emissions.

Section 1 – The hull and its pressure limitations

1.1 Allowable cargo tank ullage pressure

1.1.1 The cargo tank structure is designed to withstand a range of design loads and parts of the tank structure will also contribute to the global longitudinal strength of the ship. The classification societies' specified load conditions and loads are applied in verification of the structural design. One such load is the combined pressure from the liquid cargo and the tank ullage pressure. The tank ullage pressure is to be minimum 25 kN/m^2 or the opening pressure of the pressure relief device (P/V valve), whichever is greater. Accordingly, the maximum allowable ullage pressure in a standard tanker is typically interpreted as 25 kN/m^2 (i.e. approximately 2,550 mmWG). It should however be noted that global strength considerations and the impact of other design loads may imply that actual allowable pressure could be higher.

1.1.2 In terms of under pressure, SOLAS regulation II-2/11.6 indicates an allowable under pressure of -700 mmWG. From a structural point of view, the maximum allowable tank under pressure is presumably lower.

1.1.3 Exceeding the maximum allowable pressures could lead to structural failures. If such a structural failure results in opening of the tank structure to atmosphere, uncontrolled VOC emissions will occur together with the possibility of oil pollution to the seas. Further, it could result in loss of inert gas protection with subsequent hazards related to fire and explosion.

1.2 Typical cargo tank venting systems

1.2.1 The design of cargo tank venting and inert gas systems is governed by SOLAS regulation II-2/11.6 and 5. Most crude oil tankers have a common cargo tank venting and inert gas main pipeline which is also used for vapour emission control (ref. section 4). Branches to each cargo tank are provided with isolation valves and blanking arrangements. The isolation valves and blanks are typically only used in connection with tank entry. SOLAS chapter II-2 requires that the isolation valves are to be provided with locking arrangements to prevent inadvertent closing/opening of said tanks. The cargo tank venting/inert gas main is connected to a mast riser. The mast riser has a minimum height of 6 metres with an IMO approved flame arrestor at its outlet. An isolation valve is provided between the cargo tank venting/inert gas main and the mast riser. Some designs have a small capacity pressure/vacuum valve fitted in a bypass across the isolation valve. This latter enables thermal breathing from cargo tanks when the isolation valve is closed. A liquid-filled P/V breaker is typically connected to the cargo tank venting/inert gas main. The P/V breaker has a capacity to accommodate the gas flow from cargo tanks during loading (125% of the loading rate and discharge rate). The cargo tank venting/inert gas main is typically used during loading and discharging operations. During loading the mast riser valve is open (unless vapour emission control is performed) and VOC is expelled to air. During discharge the same valve is closed and inert gas used to replace the tank atmosphere. The cargo tank venting/inert gas main is also used during voyage but the mast riser valve will be operated only in the event of increasing ullage pressure.

1.2.2 In addition to the common cargo tank venting/inert gas main, each cargo tank is required to have a pressure/vacuum relief device for thermal breathing in the event the cargo tank is isolated from the common cargo tank venting/inert gas main. Although classification societies accept that these devices have the capacity to accommodate gas volumes resulting from variations in cargo temperature only (i.e. thermal breathing), latest industry practices have led to the installation of devices with the capacity to accommodate the full gas flow from loading of cargo tanks.

1.3 Typical settings of pressure/vacuum relief devices

1.3.1 Although the design pressure of cargo tanks is typically +2,500 mmWG and -700 mmWG, the typical setting of pressure/vacuum valves on crude tankers is +1,400 mmWG and -350 mmWG.

1.3.2 The typical settings of the P/V breakers are +1,800 mmWG and -500 mmWG. It should be noted that for liquid filled P/V breakers, the settings have to take into account ship movement (rolling and pitching) as specified by the classification societies.

Section 2 – Crude Oil Tanker Pressure control/release systems

2.1 Introduction

2.1.1 Traditionally, vapour release from crude oil tankers occurs on three discrete occasions, they being: during loading, during the loaded voyage to the discharge port, and during the ballasting of cargo tanks at the discharge port.

2.1.2 Since the introduction of the International Convention for the Prevention of Pollution from Ships together with its Protocol in 1978 (MARPOL), tankers built after 1 June 1982 (regulation 18), termed MARPOL tankers, are all designed with the required totally segregated (designated) ballast tanks. With these regulations in force, cargo tanks are never used for the loading of ballast, except on very rare occasions for bad weather purposes where one of the Crude Oil Washed cargo tanks is dedicated to take in ballast water. Therefore, the displacement of vapour from the relevant crude oil cargo tank at the discharge port has ceased to occur for the MARPOL compliant type tankers. Given this situation then, only two occasions remain where vapour emissions from crude oil tankers generally occur, namely on loading and during the transportation of the cargo.

2.2 Load Port Displacement of VOC

2.2.1 Displacement of crude oil cargo vapours at the loading port continues to occur. The reasons for the existence of these volumes of this displaced, but co-mingled[1], vapour must be subdivided and attributed to two discrete tanker operations; namely existing vapour in the cargo tank system before loading and, the evolved vapour created during the loading programme.

2.2.2 The first portion of the vapour displaced from the cargo tanks to be considered is that from the evolved vapour generated during the previous discharge programme and in particular that vapour generated as a result of the Crude Oil Washing of the cargo tanks. The concentration of this proportion of vapour within the co-mingled gas mixture within a cargo tank can be

[1] The vapour emissions on loading are a mixture of hydrocarbon vapours and the inert gas introduced into the cargo tank to achieve a positive pressure within the cargo tank system.

determined prior to commencement of the loading process. The second portion of vapour displaced is that that develops or evolves during the loading programme itself. This vapour evolves as a result of, both, the turbulence generated in the cargo tanks due to the volumetric rate of loading and the pressure differentials within the loading pipeline system creating a degree of "flashing" of the vapour from the incoming crude oil.

2.2.3 To illustrate the extent of these gases within a cargo tank system on a tanker during a loading process, Figure 2.1 below shows the measurements of hydrocarbon vapour concentrations as taken from a tanker during its loading programme. The "X" axis of the graph records the percent status of loading of the tanker whereas the "Y" axis records the percentage of hydrocarbon vapour (VOC) concentration. The graph primarily records the total hydrocarbon gas concentration at the differing percentages of loading of the cargo tanks. However, this total figure is then mathematically proportioned and subdivided, taking into consideration the diminishing size of the vapour volume in the cargo tanks, into the two concentrations of vapours, namely those present at the commencement of loading (in the event approximately 4% of the total tank vapour volume) and the concentration of vapours that evolve as a result of the loading process.

2.2.4 These vapours are displaced by the incoming cargo volumes, throughout the loading period, and released through the ship's vapour pipeline system (inert gas pipeline) to atmosphere via the ship's mast riser. In order to prevent excess pressures within the cargo tank system the isolation/control valve to the mast riser is fully opened at the commencement of loading and remains opened until completion of loading. Once the mast riser valve is shut and loading is completed, the necessary "in tank" positive pressure is achieved to prevent any form of air/oxygen entry into the cargo tank vapour system as is required by the SOLAS regulations.

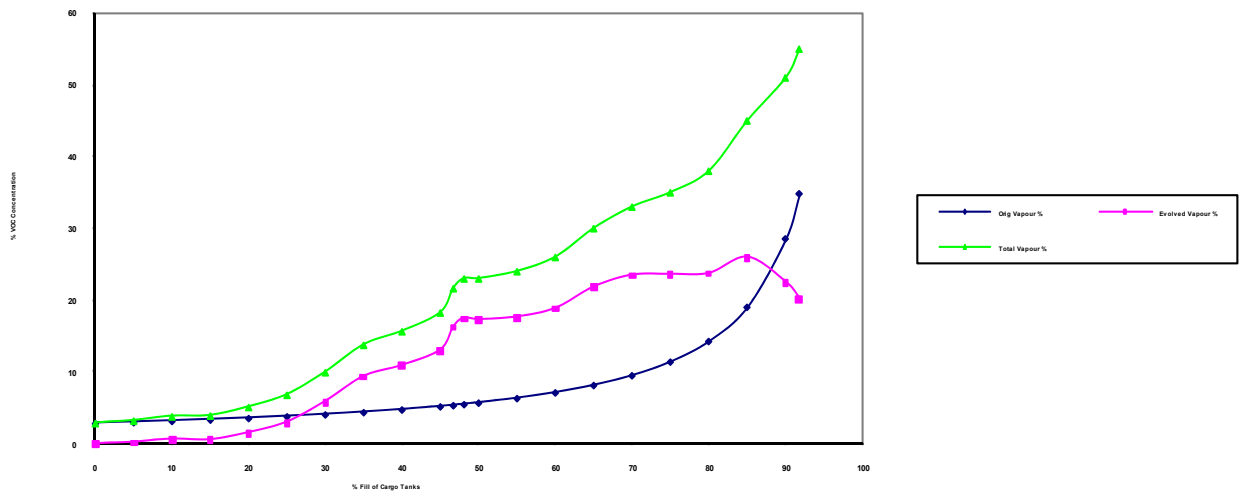


Figure 2.1 – Hydrocarbon vapour concentration in the vapour phase during a loading

2.2.5 In Figure 2.2 below, a photograph shows the deck of a tanker and highlights the relevant pressure control and release mechanisms, namely the vessel's mast riser, the individual tank Pressure/Vacuum (P/V) valves and the secondary safety mechanism of the P/V breaker. These mechanisms will be explained further in this section.

Figure 2.2 – Main Cargo Deck of a Crude Oil Tanker

2.2.6 Typically a normal loading programme will take about 24 hours for a VLCC with a volumetric rate of loading of up to 20,000 m^3/hour. The mast riser is normally used during loading for tank vapour pressure control. Its exit location, being at least 6 metres above the deck, allows for the free flow of the vapours displaced from the cargo tanks by the incoming liquid crude oil at the rate of loading of the cargo. The rate of displacement of VOC vapours from the cargo tank system will be the same as the loading rate but the concentration of VOC vapours in the displaced stream will be greater dependent upon the extent and rate of evolution of VOC vapours (vapour growth) from the incoming cargo that would add to the volume of gas/vapour mixture already existent in the cargo tank prior to loading, as shown in Figure 2.1 above.

2.3 VOC release during the voyage

2.3.1 During the voyage, the temperature of the gases/vapours in the ullage space of the cargo tanks and the liquid cargo varies. The gas phase consists of a mixture of unsaturated gases (Inert Gas – for tank safety and protection) and saturated vapours (evolved hydrocarbon vapours from the cargo). The temperature of the gas phase of the tank varies diurnally with its maximum temperature being achieved by mid afternoon and its coolest temperature in the early hours of the morning. The liquid phase temperature varies very much slower and is dependent upon both the hull design and the temperature of the surrounding seawater.

2.3.2 Figure 2.3 below records, as an example, the vapour pressure and cargo temperature data of a reported voyage for a single hulled (but segregated ballast) tanker. The graph records on the "X" axis the days of the voyage whereas the "Y" axis records both the cargo temperature (^oC) and the pressure (mmWG) within the vapour phase of the cargo tank system. Superimposed upon the graph is both the normal operational release pressure as well as the P/V valve opening

pressure levels. The vapour pressure readings were recorded every four hours whereas the cargo liquid temperature readings (blue) were recorded daily.

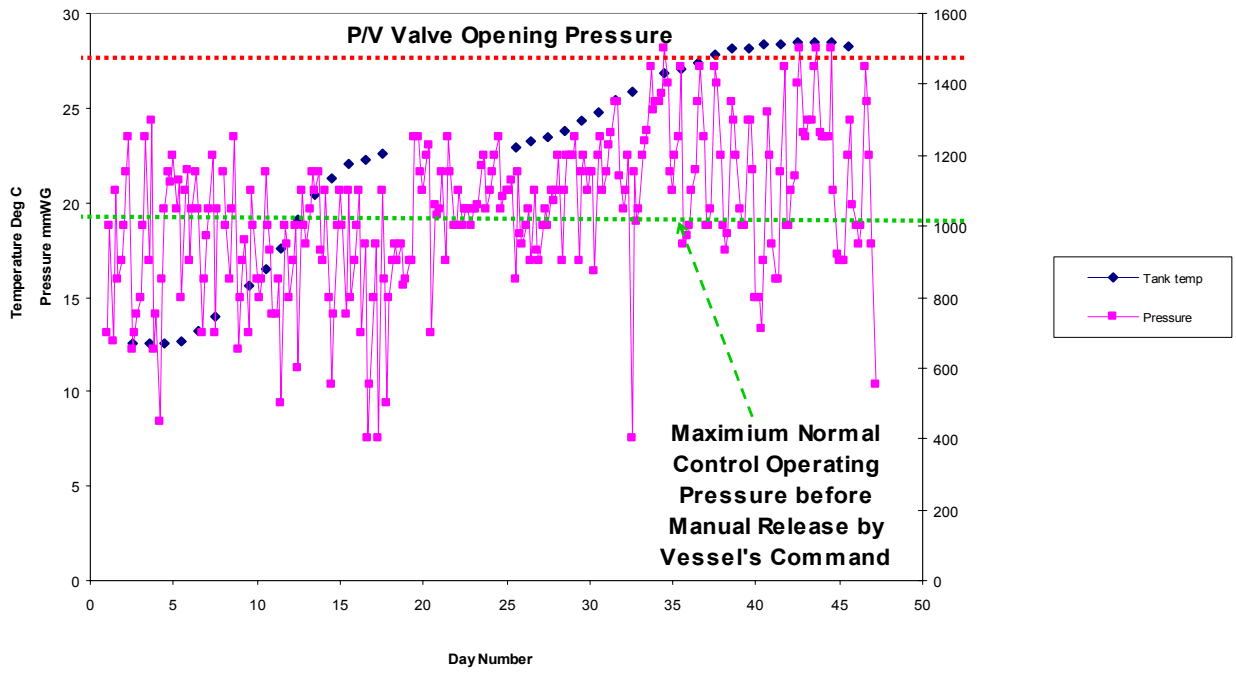


Figure 2.3 – Temperature and Pressure profile for a crude oil voyage

2.3.3 The double hulled construction of a crude oil tanker has a void/ballast space located between the cargo tank and the outer hull, this causes the temperature of the liquid cargo to remain closer to the temperature of the cargo upon loading for a longer period due to the so called "Thermos Effect" or heat loss insulation created by the void or empty ballast space. The cargo temperature profile, as shown in Figure 2.3, reflects the expected changes to temperature for a cargo carried on board a single hulled vessel where the impact of the seawater temperature upon the cargo is more apparent. This aspect can be more clearly seen in Figure 2.3 for the early/interim days of the 47-day voyage from North Sea to the Far East.

2.4 A Crude Oil Tanker's vapour pressure control mechanisms

2.4.1 A crude oil tanker is designed and constructed to withstand high vapour pressures up to a certain value. In order to protect the vessel's structure against excessive pressures, two differing levels of safety mechanisms are installed to control and limit the pressures exerted in the vapour phase of the cargo system. The installation of both these systems is a requirement within the International Convention for the Safety of Life at Sea (SOLAS). These mechanisms are:

.1 the individual tank Pressure/Vacuum (P/V) valve; and

.2 the common Pressure/Vacuum (P/V) breaker.

2.4.2 The P/V valve is the primary mechanism for the protection from cargo tank over pressure. The design and operational requirements of the P/V valves are set out in the ISO 5364:2000 standard but the opening and closing pressure setting of the individual valves is set in accordance with the designed tolerance of the relevant structure having applied the necessary safety margins.

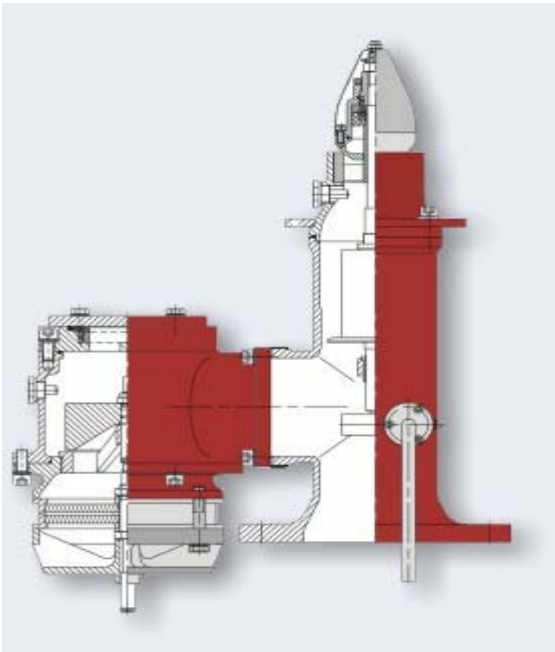


Figure 2.4 – A design and construction of a P/V valve[2]

2.4.3 A design of a P/V valve may be seen in Figure 2.4 above. The valve is fitted to a vertical pipeline connected directly to the vapour space of a cargo tank (see Figure 2.2 above). The valve consists of two sections, namely the vacuum protection section on the left hand side of the valve as shown and the pressure control mechanism of the right hand side. Both mechanisms rely upon a weighted diaphragm that will be lifted when the pre-designed pressures are met. On the pressure side of the valve the exit nozzle is designed such that the exit velocity of the vapours reach the required velocity so as to maintain the deck working area clear of hydrocarbon vapours.

2.4.4 Each cargo tank is normally equipped with its valve so that full protection is available, should the individual cargo tank be isolated from the main common vapour system on board the tanker. The typical pressure setting for a P/V valve is traditionally measured in millimetres of water gauge and would be in the range from 1,400 to 1,800 mmWG. These valves are supported on a connecting pipeline to the tank's atmosphere by a 100 to 150 mm diameter pipeline and located at least 2 metres above the deck. Due to the requirements to prevent mechanical damage to these valves the closing pressure is controlled by a damping mechanism (to prevent hammering of the valve). As a result of the damping mechanism the closing pressure of the valve will vary but will be in the range of 400-800 mmWG.

[2] Courtesy Pres-Vac Engineering A/S: www.pres-vac.com.

2.4.5 Supporting the over pressure safety system of the P/V valve is the secondary safety mechanism of the P/V breaker. In the event of a rapid pressure fluctuation within the common vapour system the P/V breaker is available to relieve such an over pressure. The single P/V breaker is located on the common vapour pipeline, serving all the cargo tank branch pipelines, which ends at the vessel's mast riser (see Figure 2.2).

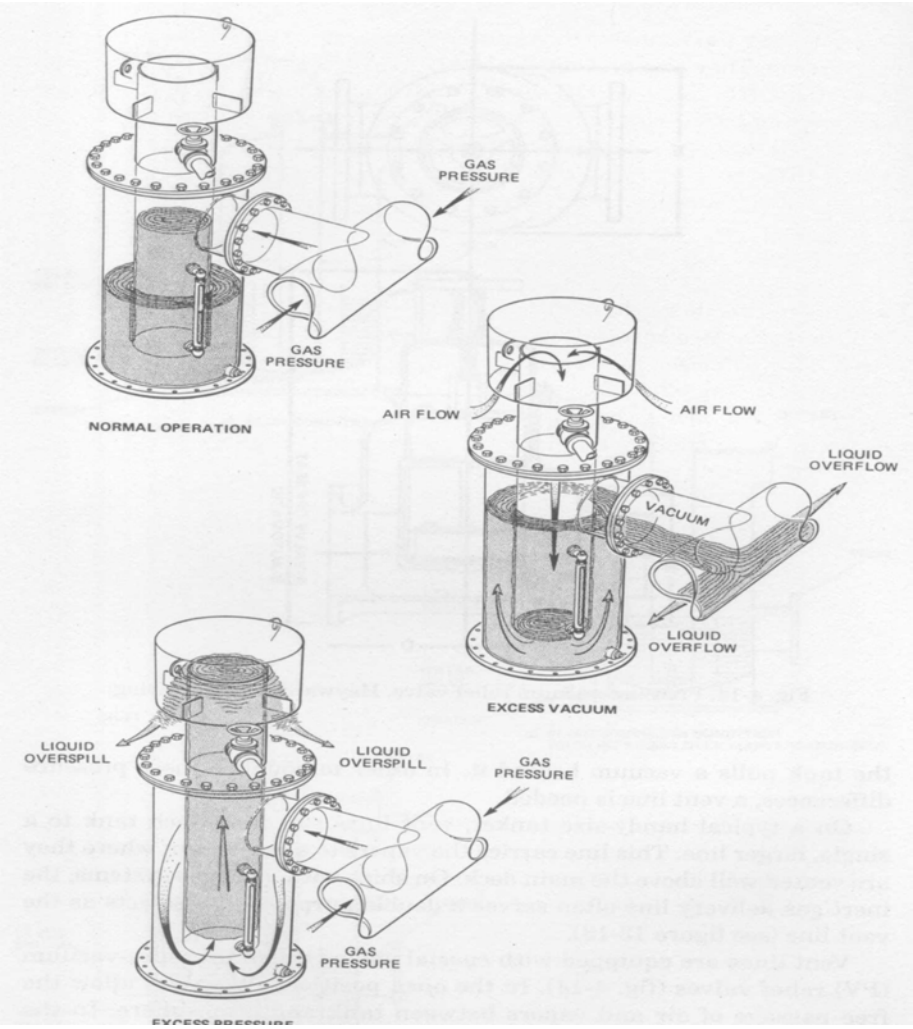


Figure 2.5 – The design and operation of a P/V breaker[3]

2.4.6 The construction and operation of the P/V breaker may be seen in Figure 2.5 above. The pressure setting in the P/V breaker is achieved by way of the internal water column with an equivalent pressure setting of approximately 2,000 mmWG. The water column also isolates the vapour phase from external air ingress into the system. In the event of an excessive pressure surge within the tank vapour system the water column would either be displaced out of the breaker onto the deck, in the event of excessive pressure, or drawn into the cargo tanks in the event of an under pressure. This will, therefore, open the total vapour system to the external environment and atmospheric pressure and, due to the equipment's dimensions, will relieve the pressure in the system very quickly. Thus, this safety mechanism, due to its pressure setting, will only operate if the vessel tank's P/V valves fail to operate or are not of sufficient capacity to relieve the pressure surge adequately.

[3] Reference – G.S. Marton, Tanker Operations – a Handbook for Ship's Officers, page 76.

2.4.7 It should, however, be noted that once the P/V breaker operates then, as stated above, it will reduce the pressure within the tank vapour system to atmospheric pressure, thereby exposing the tank system to ingress of oxygen. Therefore, this system is a "last resort" system to preserve the structure of the tanker from damage.

Section 3 – VOC generation systems in Crude Oil

3.1 Why limit VOC Emissions to the atmosphere? VOCs are a pollutant to the air and act as a precursor to the formation of Tropospheric Ozone – commonly termed Smog.

Thus, to control this emission, there are four criteria that impact on the extent and rate of evolution of gaseous VOC from crude oils and its subsequent release to atmosphere. These are:

.1 the volatility or vapour pressure of the crude oil;

.2 the temperature of the liquid and gas phases of the crude oil tank;

.3 the pressure setting or control of the vapour phase within the cargo tank; and

.4 the size or volume of the vapour phase within the cargo tank.

Each of these criteria are defined and briefly explained below together with any interaction between the criteria for general operational circumstances.

3.2 **The volatility or vapour pressure of the crude oil**

3.2.1 Reid Vapour Pressure (RVP) – this is an industrially developed standard test method to determine the Air Saturated absolute Vapour Pressure of volatile, non-viscous hydrocarbon liquids in compliance with the requirements specified in the Institute of Petroleum test procedure IP 69.

3.2.2 The RVP is the vapour pressure obtained within a standardized piece of test equipment for the evolved hydrocarbon vapour at a temperature of 100ºF or 37.8ºC. The standard test parameters for the determination of this pressure are important to identify and relate to the ratio of a fixed liquid volume to a fixed vapour volume. This ratio is one part liquid to four parts vapour. Thus, the pressure reported for this parameter reflects, in principle, the pressure that would be registered when the cargo tanks are about 20% loaded.

3.2.3 This leads to the importance of two other parameters, namely the Saturated Vapour Pressure and Unsaturated Vapour Pressure. These two parameters, and the physics behind them, give more clear indications and guidance with respect to a crude oil's volatility with respect to vessel operations and VOC control.

3.2.4 Saturated Vapour Pressure (SVP)[4] – is the equilibrium pressure generated by the liquid phase for the vapour volume within a defined system. The Saturated Vapour Pressure is developed only by the evolved hydrocarbon vapours from the crude oil liquid phase. For a Saturated Vapour to be present it must have contact with its own liquid phase. If the liquid phase temperature

[4] An empirical equation exists to correlate the Reid Vapour Pressure (psia) to the Saturated Vapour Pressure of a crude oil at the constant temperature of 37.8°C. This equation is: $\mathbf{P = (6.2106^{*} \ Ln \ P_R) + 4.9959}$; Where P is the Saturated Vapour Pressure (psia) at 37.8°C and P_R is the Reid Vapour Pressure (psia) at the same temperature.

increases or decreases so will the Saturated Vapour Pressure vary accordingly – an increase the liquid temperature will cause an increase in the Saturated Vapour Pressure.

3.2.5 However, if the vapour volume increases or decreases for a known liquid temperature, the pressure should, in theory, remain constant (for further understanding on this parameter see paragraph 3.5.2 below). These circumstances, respectively, will only cause the vapour to condensate and fall back to the liquid phase or more vapour to evolve from the liquid phase to maintain the Saturated Vapour Pressure. This physical characteristic is indicative of equilibrium pressure – between the liquid and vapour phases within the defined system.

3.2.6 From the foregoing it can be readily recognized that Saturated Vapour Pressure should not vary with the size of the vapour volume and will only vary with the temperature of the liquid phase – not the vapour phase temperature.

3.2.7 Unsaturated Vapour Pressure (UVP) – contrary to the concept of Saturated Vapour Pressure, an Unsaturated Vapour is not in contact with its liquid phase. In this case the vapour is obtained from other sources such as air or, more likely, Inert Gas. Thus, by reference to the standard laws of physics and what is termed the Ideal Gas Law[5], both variations in volume and/or temperature (this time it is the gas or vapour phase) will vary the pressure within a closed system.

3.2.8 From an operational perspective this type of behaviour is the primary cause of the variation of pressures within a cargo tank system over a 24-hour period and is to be associated with the Inert Gas phase within a cargo tank. However, the pressure generated from this type of gas/vapour is not the total vapour pressure in the cargo system.

3.2.9 Behind the pressure generated from the Unsaturated Vapours (Inert Gas) lies the pressure generated by the Saturated Vapours (the hydrocarbon vapours evolving from the crude oil cargo). As stated above, this pressure will remain as a constant for a given cargo/liquid temperature and, as is well recognized, a cargo temperature will not vary to the same extent as the vapour temperature due to heating or cooling from external sources (sunlight, sea temperature, air temperature, etc.). Thus, the variation for the tank observed Total Vapour Pressure is due to the presence of Inert Gas in the cargo tank.

3.2.10 Total Vapour Pressure – this pressure is the total pressure to be achieved within a defined closed system given the variable parameters of vapour volume and the differing control temperatures. In fact it is the combination or addition of the Saturated and Unsaturated Vapour Pressures (Dalton's Law of Partial Pressure[6]) within a closed and defined system.

3.2.11 Thus, on board a tanker, the pressure measured within Vapour System is the Total Vapour Pressure of the system which is the sum of the two individual pressures generated by the differing types of gases present in the system.

---

[5] The Ideal Gas Law equation is **PV = nRT** or **P = (nRT)/V** where: P = Pressure, T = Temperature, V = Volume and nR are gas constants.

[6] Dalton's Law of Partial Pressure states that "The pressure of a mixture of gases is the sum of the partial pressures of its constituents".

3.3 The temperature of the crude oil in a cargo tank

3.3.1 The measurement and determination of temperature upon the two differing phases in a crude oil cargo tank have differing impacts upon the size and extent of pressure exerted at any one time in the cargo tank. In this regard it is necessary to consider the two phases separately with regard to the impact of temperature.

3.3.2 The temperature of the liquid in a crude oil cargo tank – the temperature of the liquid phase in a crude oil cargo tank will vary little over the period of a voyage unless cargo heating is being undertaken. It is this temperature that determines the Saturated Vapour Pressure that will be exerted by the evolving VOCs from the cargo volume and contribute to the Total Vapour Pressure in the cargo tank at any one time. The cooler the liquid phase temperature the lower will be the Saturated Vapour Pressure of the crude oil but care should be taken not to allow cooling of waxy cargoes too much, such that it promotes wax precipitation.

3.3.3 The temperature of the vapour or gas in a crude oil cargo tank – the temperature of the gas phase in a cargo tank will change more rapidly and vary during the day/night cycle. As this phase in the cargo tank contains a mixture of Saturated (evolved hydrocarbon gases) and Unsaturated (Inert gas) gas species the pressure in this space will vary with temperature due to the reaction of the Unsaturated Gas component to temperature (Ideal Gas Law[5]). Thus, during the day when the gas phase warms, the pressure in the tank will increase so long as there is an Inert Gas component in the gas phase. The obverse will occur at night as the gas phase cools.

3.4 The pressure setting or control of the vapour phase within the cargo tank

3.4.1 The technologies available on board crude oil tankers for the control of pressure within the cargo tank vapour system are discussed in section 2. However, it is important to identify the significance of pressure with respect to the evolution of hydrocarbon vapours from a crude oil liquid phase.

3.4.2 Control of the extent of the pressure within a crude oil cargo tank vapour system will determine the extent of further vapour evolution from a crude oil cargo. If the pressure within the system is controlled at the Saturated Vapour Pressure of the cargo, then equilibrium pressure between the liquid and vapour phase is obtained and no further VOC will evolve from the cargo. However, if the vapour pressure in the crude oil tank vapour system is reduced to a pressure below the Saturated Vapour Pressure of the cargo, then VOC will evolve to restore the equilibrium balance in the system.

3.5 The size or volume of the vapour phase within the cargo tank system

3.5.1 The size or volume of the gas or vapour phase in the cargo tank system (usually a common system on a crude oil tanker due to the interconnection through the Inert Gas pipeline system) is an important criterion to establish the pressure within the system. Again separate consideration should be given to the two differing types of gases to be found in the vapour phase and how volume may impact these component gases.

3.5.2 Saturated vapours from the crude oil liquid phase, as described above in paragraph 3.2.2, under theoretical conditions the pressure generated by saturated vapours will not be affected by a change in the volume space occupied by the vapours. However, due to the numerous species of hydrocarbon types to be found in evolved vapour from a crude oil it has been found that a volumetric change of the vapour phase from a 2% volume (V:L ratio of 0.02) to a 20% volume

(V:L ratio 0.2) will impact the saturated vapour pressure of a crude oil at a constant temperature. For vapour volumes greater than 20% of the total volume the pressure behaves similar to that expected of a Saturated Vapour; namely nearly isobaric. These circumstances can be seen in Figure 3.1 below for a selection of crude oil types.

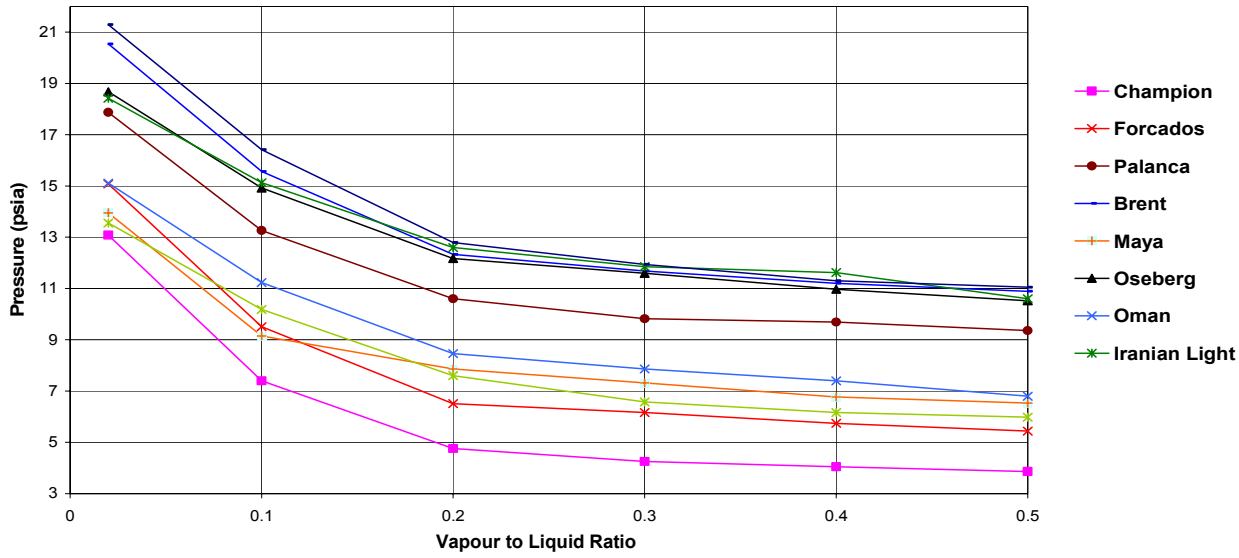


Figure 3.1

3.5.3 The change in pressure with respect to volume, for a vapour percent volume from 2% to 20%, for complexed vapour phases evolved from crude oils, is due to the influence of the individual volatile hydrocarbon types and their varying proportions in both the liquid and vapour phase that separately contribute to the final saturated vapour pressure under equilibrium conditions. The ratio of concentration of the individual hydrocarbon compounds in the vapour phase is due to the *Partition Coefficients* for each hydrocarbon type in relation to another type. This will cause a differing distribution of hydrocarbon species to that in the liquid phase when the vapour phase volume is smaller.

3.5.4 Unsaturated gases (Inert Gas) in the vapour phase system – this type of gas behaves in a manner simulated by the Ideal Gas Law equation[5]. Therefore any reduction in the volume occupied by this gas will cause an increase in the pressure exerted by the gas at a known temperature.

Section 4 – Methods and systems for the control VOC

In this section, examples of methods and systems for the control of VOC are provided.

4.1 Methods and systems for the control of VOC during Loading

4.1.1 Best Practices and design

.1 Manual pressure relief procedures (tank pressure control);

.2 P/V valve condition and maintenance;

.3 Condition of gaskets for hatches and piping;

.4 Inert gas topping up procedures;

.5 Partially filled tanks;

.6 Loading sequence and rate; and

.7 Use of vapour return manifold and pipelines when shore facilities are available.

4.1.2 **Vapour Emission Control Systems**

The principle behind VECS is that VOC generated in cargo tanks during loading is returned to the shore terminal for processing, as opposed to being emitted to atmosphere through the mast riser.

Vapour Emission Control Systems (VECS) were introduced in 1990 as a requirement for tankers loading oil and noxious liquid substances at terminals in the United States (USCG 46 CFR Part 39). IMO followed up with the introduction of IMO MSC/Circ.585 "Standards for vapour emission control systems" in 1992. International regulation requiring vapour emission control was introduced through regulation 15 of MARPOL Annex VI adopted in 1997, although it is only required for ships loading cargo at terminals where IMO has been informed that VECS is mandatory.

Since 1990, most crude tankers have installed a VECS system in compliance with USCG regulations. The regulations cover both the technical installation (vapour recovery piping and manifold, vapour pressure sensors and alarms, level gauging, high level and independent overflow alarms) as well as operational restrictions and training. The operational restrictions are found in a mandatory VECS manual which also includes maximum allowable loading rates. The maximum allowable loading rate is limited by one of the following:

.1 the pressure drop in the VECS system from cargo tank to vapour manifold (not to exceed 80% of the P/V valve setting);

.2 the maximum pressure relief flow capacity of the P/V valve for each cargo tank;

.3 the maximum vacuum relief flow capacity of the P/V valve for each cargo tank (assuming loading stopped while terminal vacuum fans are still running); and

.4 the time between activation of overfill alarm to relevant cargo tank being full (min. 1 minute).

The calculations are to be based on maximum cargo vapour/air densities as well as maximum cargo vapour growth rates, which again may limit the cargoes that can be loaded with VECS.

Further, the calculations are to be carried out both for single tank and multiple tank loading scenarios.

The USCG regulations also contain additional requirements to vapour balancing, i.e. for tankers involved in lightering operations. These include operational requirements as well as technical requirements for an in-line detonation arrestor, oxygen sensors with alarms and possibly means to prevent hazards from electrostatic charges.

For ships provided with a VECS system as per IMO or USCG regulations, the control of VOC emissions will be through returning VOC to the shore terminal in accordance with the procedures found in the onboard VECS manual.

The maximum allowable loading rates and corresponding maximum vapour/air densities and vapour growth rates should be specified in the VOC management plan.

4.1.3 Vapour Pressure Release Control Valve (VOCON valve)

The VOCON valve operates as a hydraulically controlled valve that controls the closing pressure for the valve and therefore undertakes a similar procedure to the manual VOCON procedure as described in 4.2.2 below. However, for the loading programme, the valve also allows a higher pressure to be maintained throughout the loading process in order to limit the extent of vapour evolution from the crude oil once saturated vapour pressure is achieved within the tank vapour system. This valve is normally a single valve facility and located at the bottom of the mast riser by way of a by-pass pipeline to the mast riser control valve. The relevant closing pressure setting for the valve may be done locally or remotely in the Cargo Control Room depending upon the sophistication of the installed system.

Figure 4.1 – Hydraulically controlled VOCON valve

Similar valves with fixed pressure arrangements are to be found and are currently installed on tankers and located at the same position; namely at the bottom of the mast riser by way of a by-pass pipeline to the mast riser control valve. These valves operate as a form of "tank breather" valve but release vapour through the mast riser.

4.1.4 Cargo Pipeline Partial Pressure control system (KVOC)

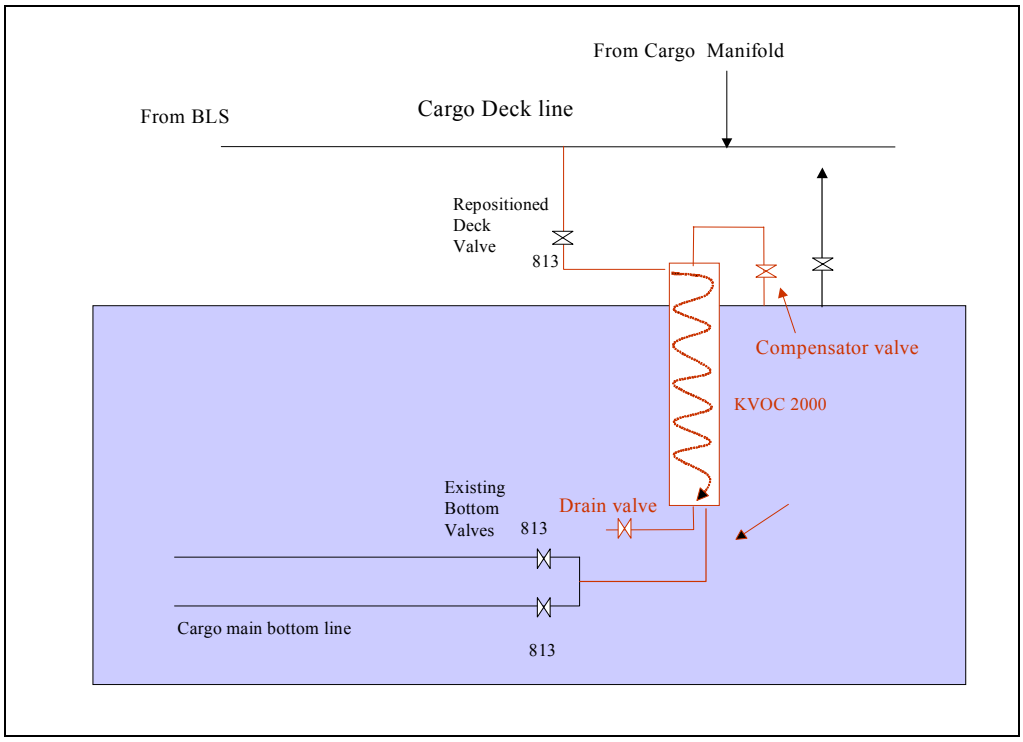
The purpose of the KVOC system installation is to minimize VOC release to the atmosphere by preventing the generation of VOC during loading and transit. The basic principle of KVOC is to install a new drop pipeline column specially designed for each tanker with respect to expected loading rate. The new drop pipeline column will normally have an increased

diameter compared to an ordinary drop line. The increased diameter will reduce the velocity of the oil inside the column and by that means ensure that the pressure adjusts itself to approximately the boiling point of the oil independent of the loading rate. In the initial phase of the loading process some VOC might be generated. The pressure inside the column will adjust itself to the SVP of the oil so that there is a balance between the pressure inside the column and the oil SVP. When this pressure has been obtained in the column the oil will be loaded without any additional VOC generation. This means that KVOC column prevents under pressure to occur in the loading system during loading.

The KVOC system is not designed to remove all VOC, but to minimize generation of VOC. VOC remaining in the tanks from the last cargo and COW operations has to be displaced from the cargo tanks when loading. Also, if the oil boiling point (SVP) is higher than the tank pressure, some crude oil will generate VOC in the tanks and additional VOC be released. Bad weather together with very volatile oil will also increase the VOC emissions due to its SVP also when KVOC is applied.

The KVOC column has an effect on the VOC release during transit, because gas bubbles have been prevented from forming. This means that the amount of gas bubbles in the oil available for release during transit will be minimized. To further reduce the release of VOC, the pressure in the cargo tanks should be held as high as possible. A high pressure, from about 800 to 1,000 mmWG, will reduce possible boiling and diffusion of VOC in the crude oil cargo tanks.

KVOC has also shown a similar effect on H_2S as on minimizing VOC generation. If the KVOC system has been installed, it should therefore always be used when loading sour crude to minimize H_2S concentration in the void spaces and release during loading and transit.



Pipeline Flow Plan for KVOC

4.1.5 **Increased pressure relief settings** ***(Applicable also for transit conditions)***

As described in sections 2 and 3, as long as the tank pressure is maintained above the Saturated Vapour Pressure of the cargo, then equilibrium is obtained between the liquid and vapour phase of the cargo and no further VOC will evolve from the cargo. This means that if the pressure/vacuum relief settings are increased to, e.g., 2,100 mmWG, VOC will not evolve from a cargo as long as the Saturated Vapour Pressure of said cargo is below the pressure relief setting.

As indicated earlier, the maximum design pressure of a cargo tank is at least 2,500 mmWG and, as such, increasing the settings of the pressure/vacuum devices up to, e.g., 2,100 mmWG, should not require additional strengthening. It will however require adjustment/replacement of P/V valves. Note that for some P/V valves designs, the pressure after initial opening increases, and this has to be taken into account if an owner intends to increase the setting of P/V valves.

Needless to say it will also require replacement/modifications to the P/V breaker, as well as water loops serving the inert gas deck water seal, as well as settings of pressure sensors and alarms in the inert gas and VECS system. It is of course also essential that onboard operational procedures in terms of manual pressure release have to be adjusted.

One additional benefit is that increasing the pressure/vacuum relief settings will increase the acceptable loading rate during VECS.

Although the primary benefit of increasing set pressure will occur during voyage. It will also have an effect related to loading, as the increased set pressure will limit the existing vapour in the cargo tanks, i.e. the vapour generated during the previous discharge and Crude Oil Washing.

For ships that have been provided with increased pressure relief settings, the VOC emissions will be controlled when the saturated vapour pressure of the crude oil is below that of the pressure relief valve settings.

It is important that terminals and cargo surveyors acknowledge that if ships with higher pressure settings are required to de-pressurize prior to cargo handling operations, this will limit the ships' ability to control VOC emissions.

4.1.6 **Vapour recovery systems – General**

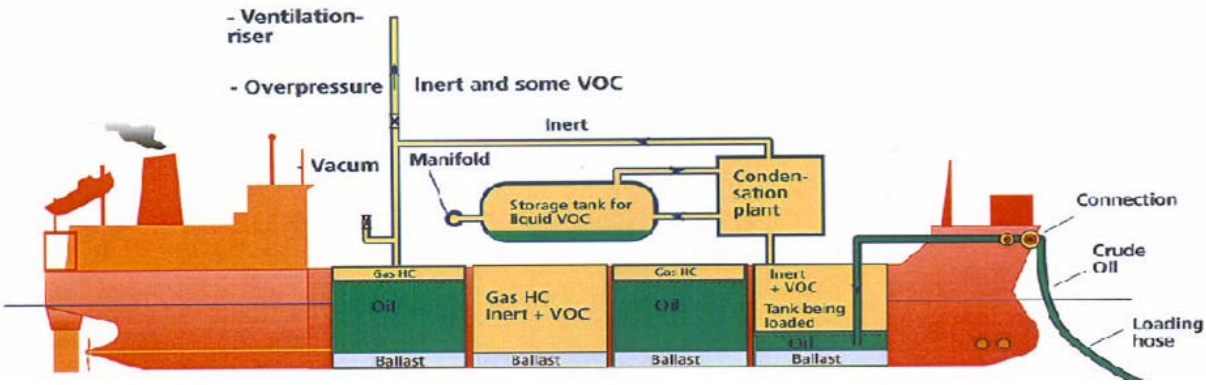
In the late 1990s certain Administrations required offshore installations to reduce their emissions of VOC and this led to the development and installation of vapour recovery systems on board shuttle tankers in the North Sea. Different concepts were developed for the purpose of reducing the emissions of VOC (VOC). The initial efficiency requirement was set to 78% (i.e. 78% less VOC emissions when using vapour recovery systems). The systems can recover VOC in all operational phases.

For ships that have been provided with vapour recovery systems, the VOC emissions will be controlled when the recovery plant is in operation.

The VOC recovery plant efficiency as well as any operational limitations related to, e.g., applicability for different cargo handling modes (loading, transit, COW), maximum allowable loading rates or crude vapour pressures, are to be specified in the VOC management plan.

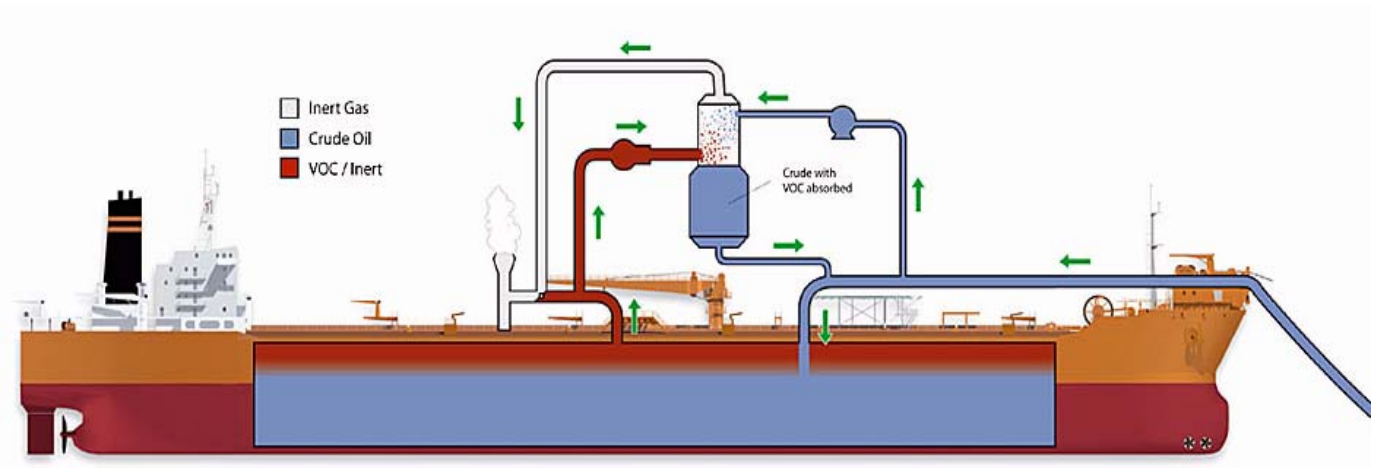
4.1.6.1 **Vapour Recovery Systems – Condensation Systems**

The principle is similar to that of re-liquefaction plants on LPG carriers, i.e. condensation of VOC emitted from cargo tanks. In the process, the VOC passes through a knock out drum before it is pressurized and liquefied in a two stage process. The resulting liquefied gas is stored in a deck tank under pressure and could either be discharged to shore, or be used as fuel (possibly including methane and ethane) for boilers or engines subject to strict safety requirements. It is also conceivable that the stored gas could be used as an alternative to inert gas subject to the Administration's acceptance.



4.1.6.2 **Vapour Recovery Systems – Absorption Systems**

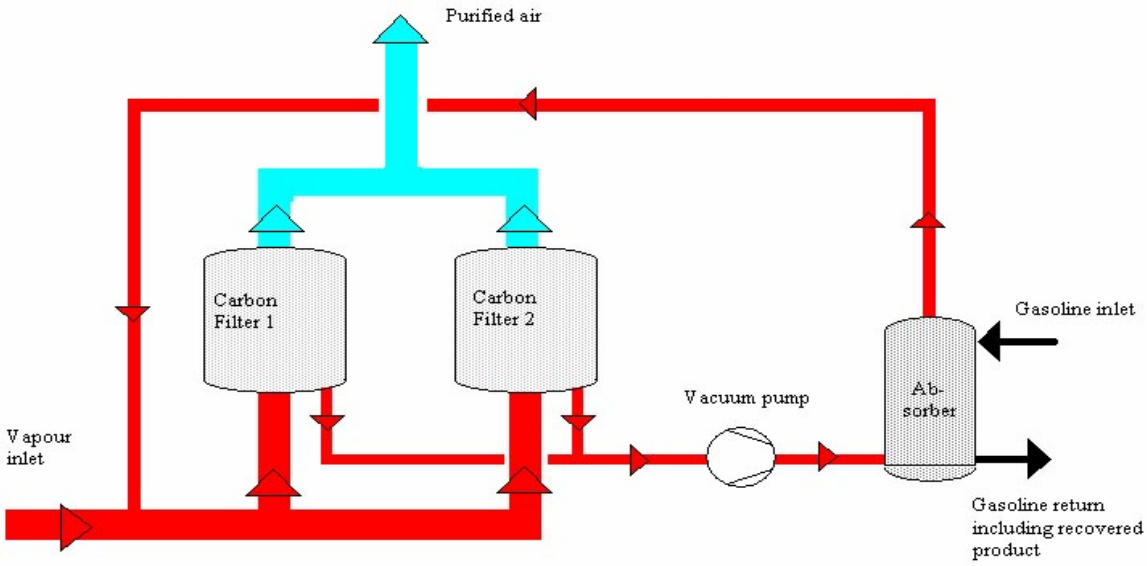
The technology is based on the absorption of VOCs in a counter-current flow of crude oil in an absorber column. The vapour is fed into the bottom of the column, with the side stream of crude oil acting as the absorption medium. The oil containing the absorbed VOC is then routed from the bottom of the column back to the loading line where it is mixed with the main crude oil loading stream. Oil pumps and compressors are used to pressurize the oil and gas. Unabsorbed gases are relieved to the riser to increase the recovery efficiency. Similar concepts have been developed using swirl absorbers instead of an absorption column.



4.1.6.3 Vapour Recovery Systems – Absorption Carbon Vacuum-Regenerated Adsorption

In the CVA process, the crude oil vapours are filtered through active carbon, which adsorbs the hydrocarbons. Then the carbon is regenerated in order to restore its adsorbing capacity and adsorb hydrocarbons in the next cycle. The pressure in the carbon bed is lowered by a vacuum pump until it reaches the level where the hydrocarbons are desorbed from the carbon. The extracted, very highly concentrated vapours then pass into the absorber, where the gas is absorbed in a stream of crude oil taken from and returned to the cargo tanks.

As carbon bed adsorption systems are normally sensitive to high concentrations of hydrocarbons in the VOC inlet stream, the VOC feed stream first passes through an inlet absorber where some hydrocarbons are removed by absorption. The recovered VOC stream may be reabsorbed in the originating crude oil in the same inlet absorber.



4.2 Methods and systems for the control of VOC during Transit

4.2.1 Best Practices/Design

.1 Manual pressure relief procedures (tank pressure control);

.2 P/V valve condition and maintenance;

.3 Condition of gaskets for hatches and piping;

.4 Inert gas topping up procedures;

.5 Partially filled tanks;

.6 Loading sequence and rate; and

.7 COW procedures (closed cycle[7]).

4.2.2 VOCON procedure

By reference to Figure 4.2 below, this procedure requires the monitoring and the recording of the pressure drop during a release of gas from the cargo tank vapour system. This can be undertaken with the use of the Inert Gas pressure gauge in the cargo control room or, as available, located on the Inert Gas pipeline on deck. Figure 4.2 shows a pressure drop profile using the mast riser and the inflection in the pressure drop where the mast riser valve should be shut.

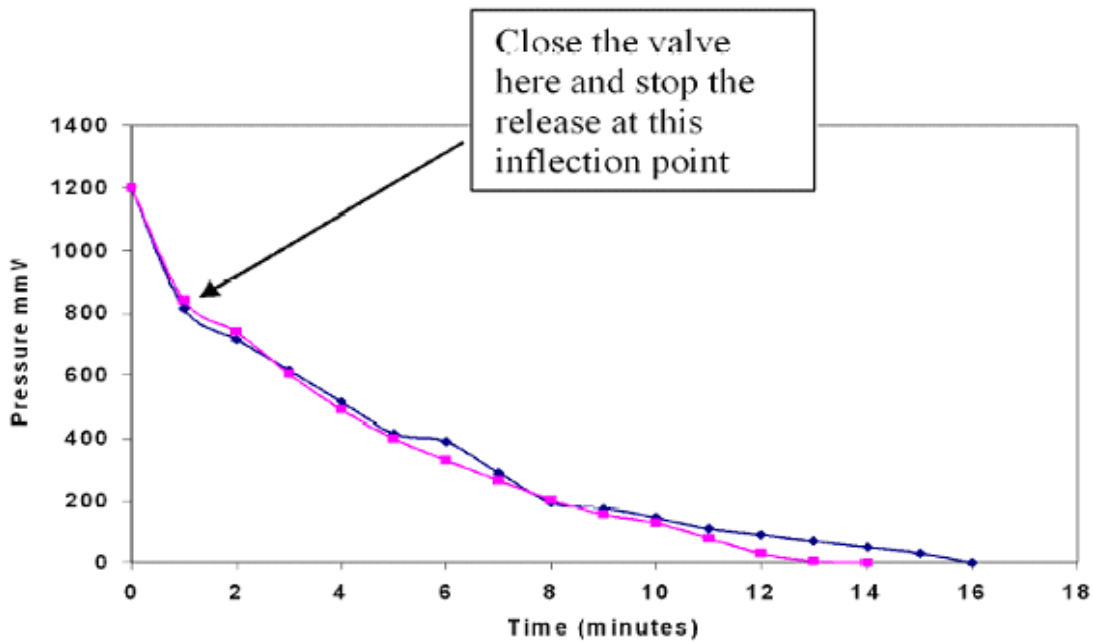


Figure 4.2 – A mast riser release

[7] "Closed Cycle" crude oil washing means that the tanker's slop tank is used as the reservoir for the crude oil wash stock and this wash stock is stripped or cycled back to the slop tank for reuse. Thus, using a defined volume of crude oil for washing of the specified cargo tanks will limit the amount of VOC associated with the wash stock volume as distinct from using fresh crude oil throughout the washing programme.

The VOCON operational procedure

(1) Before opening the mast riser, note the pressure in the Inert Gas pipeline system.

(2) Open the pressure release valve and record/monitor the pressure within the Inert Gas pipeline at regular short intervals (every 30 seconds for a mast riser release).

(3) Plot the pressure drop profile. This can be achieved either manually or by use of the Inert Gas Oxygen and Pressure Recorder in the Cargo Control Room but an increase in the Recorder paper feed rate will be required to achieve definition of the plot.

(4) When the rate of pressure drop becomes constant (after the initial rapid pressure drop) then the gas release should be stopped and the valve closed.

(5) Monitor the Tank Gas Pressure after completion of the controlled release in order to check the final pressure obtained within the Vapour/Inert Gas system.

Advice Notes

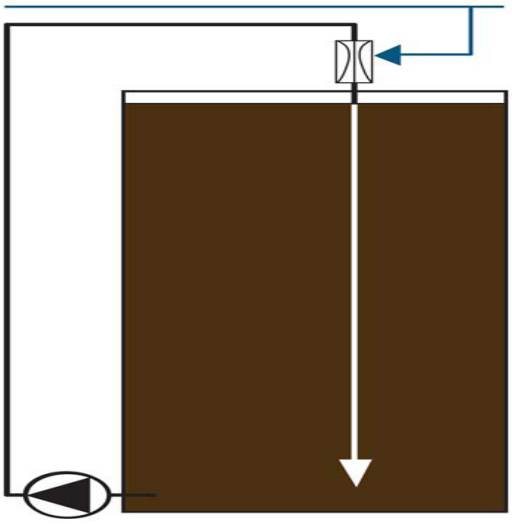
(A) A review of Figure 4.2 shows a clear change in the rate of pressure drop during the release period. If the gas release continues after this point then the pressure in the Inert Gas system will be quickly restored to the pressure associated with the point where the rate of pressure drop changes.

(B) If there is a straight line drop of pressure observed and no inflection observed by 800 mmWG, then close the release valve anyway.

(C) By reference to the ISGOTT Publication, all safety measures should be taken to minimize the hazards associated with vented gases from the vessel's cargo tank system.

4.2.3 **Recovery of excess VOC and tank absorption (Venturi system)**

The Venturi system involves a process where evolved VOC is reabsorbed back into the cargo. The system typically consists of a pressure controlled pump, feeding oil to a unit with Venturi(s). The Venturi draws VOC, H_2S and inert gases (IG) from the common cargo tank venting/inert gas main line. The Venturi unit is designed to generate a bubble size optimal for their collapse in the crude oil cargo and rapid absorption. Released near the tank bottom, the soluble compounds are kept dissolved by the pressure head there. Inert gas will eventually surface.



Oil is pumped from a cargo tank through the Venturi unit. Gas is sucked in from the main inert gas line and injected at the bottom of the tank.

For ships that have been provided with a Venturi type system, the VOC emissions will be controlled when the system is in operation.

The VOC control system efficiency as well as any operational limitations related to, e.g., applicability for different cargo handling modes (loading, transit, COW), maximum allowable loading rates or crude vapour pressures, are to be specified in the VOC management plan.

4.3 **Methods and systems for the control of VOC during Discharging/Ballasting**

Emissions of VOC during ballasting had relevance when tankers took ballast into cargo tanks for stability and longitudinal strength reasons and thus displaced VOC from cargo tanks being ballasted. After the implementation of requirements to segregated ballast tanks and, of course, double hull, VOC releases during discharge and ballasting are no longer an issue.

During discharging of cargo tanks, it is important that pressure monitoring is exercised in order to avoid excessive supply of inert gas to cargo tanks.

Section 5 – The Monitoring and Control of VOC Releases

5.1 Record keeping is necessary in order to document compliance with the requirements of the management plan and, potentially, the extent of release of gases from the crude oil cargo tanks. The form of record keeping is dependent upon the specific form of method used to minimize the emission of VOC from the crude oil cargo. It will also be dependent upon the operation being performed by the ship necessitating the release of VOC, namely loading during the carriage or as a result of a crude oil washing (COW) operation.

5.2 As a general example of the type and scope of record keeping to be undertaken on board the crude oil tanker, the methodology of the manual VOCON procedure is used. The appropriate record keeping is as follows:

.1 The target or minimum pressure within the tank gas/vapour system for the specific voyage

.1.1 A record of the time and pressure within the tank gas/vapour system before the release takes place.

.1.2 A record of the time and pressure within the gas/vapour system after the release has been completed.

5.3 The foregoing data and information may be compiled by the ship's management company or operators in order to assess or quantify the extent or degree of VOC release. As an outline to such assessment the following can be taken into consideration:

.1 For those ships operating with manual VOC control by the VOCON procedure, the released volume of gas/vapour can be estimated by use of the pressure change (opening to closing pressures) relationship to the total gas/vapour volume in the cargo tank vapour system (Ideal Gas Laws – reference to section 3).

Section 6 – Training Programme

6.1 A training programme is to be developed for the persons intended to assume overall charge of the VOC management on board each ship. The programme is to include the following:

.1 An introduction to the purpose of VOC emission control:

.1.1 Volatile organic compounds (VOCs) may be toxic, and when they evaporate into the air they can react with Nitrogen Oxides (NO_x) in sunlight and split apart oxygen molecules in air and thereby form ground-level ozone, commonly referred to as smog. The layer of brown haze it produces is not just an eyesore, but also is a source of serious illnesses. Ozone is extremely irritating to the airways and the lungs, causing serious damage to the delicate cells lining the airways. It contributes to decreased lung function, increased respiratory symptoms and illnesses.

.1.2 Regulation 15 of MARPOL Annex VI

.2 An introduction to the principles of VOC emission control:

.2.1 VOC generation systems in crude oil (ref. section 3)

.2.2 Crude oil tanker pressure control/release systems (ref. section 2)

.3 General VOC emission control options:

.3.1 Methods and systems for the control of VOC emissions (ref. section 4)

.4 Ship specific VOC emission control options:

.4.1 Ship specific methods and systems for the control of VOC emissions (ref. section 4)

.5 Monitoring and recording of VOC release:

.5.1 Methods for monitoring and recording of VOC emissions (ref. section 5)

.6 Hazards and Safety related to VOC emission control:

.6.1 The hull and its pressure limitations (ref. section 1)

.6.2 Personnel safety hazards related to exposure to crude oil vapour.

Section 7 – Designated Person

7.1 A person should be designated to assume overall charge of the VOC management on board the ship.

The designated person should preferably have:

.1 At least one year's experience on crude oil tankers where his or her duties have included all cargo handling operations relevant to VOC management. In the absence of experience with VOC management, he or she should have completed a training programme in VOC management as specified in the VOC management plan;

.2 participated at least twice in cargo loading operations, Crude Oil Washing Operations and transit where VOC management procedures have been applied, one of which should be on the particular ship or a similar ship in all relevant aspects, for which he or she is to undertake the responsibility of VOC management; and

.3 full knowledge of the contents of the VOC management plan.

Section 8 – List of drawings

8.1 The following drawings are recommended included as appendices to the management plan:

.1 General Arrangement drawing;

.2 Tank plan;

.3 Schematic drawing(s) of the Cargo tank venting system;

.4 Schematic drawing of the inert gas system;

.5 Schematic drawing of the vapour emission control systems (if applicable);

.6 Schematic drawing(s) Vapour Recovery System or other VOC control systems; and

.7 Details of pressure vacuum relief devices including settings and capacities.

References:

.1 Vapour Emission Control System manual (if applicable);

.2 Vapour Recovery System manual (if applicable);

.3 Other VOC control system manual (if applicable);

.4 Inert Gas manual; and

.5 COW manual.

AIR QUALITY ANALYSIS

Texas Gulf Terminals Inc.
Western Gulf of Mexico

Appendix C

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July 2018

Environmental solutions delivered uncommonly well

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1. INTRODUCTION

Texas Gulf Terminals Inc. (TGTI) proposes to construct a deep water port (DWP) crude loading terminal located in federal waters of the Gulf of Mexico (GOM) approximately 15 miles east of Corpus Christi, Texas. TGTI is filing this Deepwater Port License (DWPL) application to obtain a license to construct, own, and operate the Project pursuant to the Deepwater Port Act of 1974, as amended (DWPA), and in accordance with the U.S. Coast Guard's (USCG's) and the Maritime Administration's (MARAD) implementing regulations. The proposed DWP will consist of one (1) single point mooring (SPM) buoy system which would be the principle component used for the loading of crude carrier vessels at the DWP. The crude oil loaded onto moored vessels at the DWP will be supplied from the Onshore Storage Terminal Facility (OSTF), through the proposed pipeline infrastructure, and to the DWP. Vessels will be moored to the proposed SPM buoy system via mooring hawsers. Floating hoses will extend from the SPM buoy system to the moored vessel to allow for the loading of crude oil.

Consistent with past US EPA guidance for similar licensing applications, TGTI is including air quality dispersion modeling in support of the overall National Environmental Policy Act (NEPA) analysis to demonstrate that the proposed operations associated with this DWP will not result in a violation of the National Ambient Air Quality Standards (NAAQS). As part of NEPA guidance, TGTI is performing this air quality analysis to account for direct, indirect, and cumulative impacts from the Project to satisfy the requirements of the June 2011 *Memorandum of Understanding regarding Air Quality Analyses and Mitigation for Federal Oil and Gas Decisions through the NEPA Process*[1].

As mentioned above, the DWP consists of the SPM buoy system that is used for loading of crude carrier vessels. Per the 1974 DWPA, the revised 2012 DWPA, and the DWP regulations (40 CFR 148.5), a DWP new source for purposes of the Clean Air Act is defined as "*any fixed or floating manmade structure* ***other than a vessel,*** *or any group of such structures, that are located beyond State seaward boundaries and that are used or intended for use as a port or terminal for the transportation, storage, or further handling of oil or natural gas for transportation to or from any State…*"[2]. Therefore, vessels are not considered primary/direct sources of emissions from the Project for Clean Air Act new source review regulatory applicability.

TGTI has included emissions from sources with an indirect impact (such as emissions from the crude carrier itself, and other emissions sources on the crude carrier deck) as part of this air quality analysis to address the requirement of direct, indirect, and cumulative impacts from the Project. Refer to Section 3.1 for additional details on the modeled sources. This modeling report details the air dispersion modeling analysis performed for the DWP to demonstrate compliance of the air quality standards at the Class II shoreline receptors, in accordance with modeling procedures promulgated by the Bureau of Ocean Energy Management (BOEM), as discussed further in Section 1.2.

[1] See scope of MOU - https://www.epa.gov/sites/production/files/2014-08/documents/air-quality-analyses-mou-2011.pdf
[2] https://www.marad.dot.gov/ports/office-of-deepwater-ports-and-offshore-activities/deepwater-port-licensing-frequently-asked-questions/

1.1 POLLUTANTS TO BE MODELED

This report details the air dispersion modeling that has been conducted for PM_{10}, $PM_{2.5}$, NO_2, CO, and SO_2 to demonstrate compliance with the NAAQS. In addition, a State Health Effects evaluation for emissions of speciated VOCs to demonstrate compliance with the Texas Commission on Environmental Quality (TCEQ) toxicology division's Effects Screening Levels (ESL) guidelines has been conducted. Section 4.2 and Section 4.3 include a discussion on the special consideration for NO_2 modeling based on recent BOEM and TCEQ state modeling guidance.

A summary of the results is shown in Table 1-1 and Table 1-2. In addition, the nearest Class I area, Big Bend National Park (NP), Texas is located at more than 300 kilometers away from the proposed operations. Therefore, Class I air quality modeling analysis has not been included in this modeling analysis. As shown in the following summary tables, the direct, indirect, and cumulative impacts from the Project on the ambient air quality are in compliance with the NAAQS for the modeled criteria pollutants.

Table 1-1. Summary of Criteria Pollutants Modeling Results

Pollutant	Averaging Period	Modeled Concentration (µg/m³)	SIL (µg/m³)	Pass at SIL (Yes/No)	Background Monitor Concentration [3] (µg/m³)	Modeled Concentration + Background Value (µg/m³)	Primary and Secondary NAAQS (µg/m³)	Below NAAQS (Yes/No)
CO	1-hour	30.72	2000	Yes	N/A	N/A	40,000	N/A
	8-hour	10.76	500	Yes	N/A	N/A	10,000	N/A
SO_2	3-hour	4.09	25	Yes	N/A	N/A	1,300	N/A
	24-hour	1.31	5	Yes	N/A	N/A	--	N/A
	Annual	0.05	1	Yes	N/A	N/A	--	N/A
	1-hour	6.22	7.9	Yes	N/A	N/A	196	N/A
NO_2	Annual	1.04	1	No	18	1.04+18	100	Yes
	1-hour[4]	69.57*	7.5	No	87	69.57+87 = 156.57	188	Yes
$PM_{10}/PM_{2.5}$	24-hour	0.80	5/1.2	Yes	N/A	N/A	150/35	N/A
	Annual	0.03	1/0.3	Yes	N/A	N/A	50/15	N/A

*H5H modeled 1-hour concentration of NO_2 = 5 year Average of H5H Maximum Modeled NO_2 Concentration

= Average (53.71, 76.46, 71.87, 65.52, 80.27)

= 69.57 µg/m³

[3] The background monitor concentration has only been included for pollutants that exceed the significant impact level promulgated by EPA.

[4] The percentile approach allows the evaluation of the NAAQS based on the 98th percentile of the 3-year average of the daily maximum values (highest 8th high, H8H). The highest 1st high (H1H) value 114.69 µg/m³ but based on the percentile approach, the air quality impacts have been evaluated based on the H5H due to unavailability of H8H values.

1.1.1. State Health Effects Review

The modeled concentrations of crude/condensate from the Modeling and Effects Review Applicability (MERA) analysis are provided in Table 1-2 below. Since the model predicted maximum hourly and annual impacts for condensate/crude do not exceed the corresponding ESLs, no further analysis is required. Please refer to Section 5-1 for detailed analysis.

Table 1-2. Summary of Modeling Results for the Health Effects Review

Pollutant/ Product	CAS Number	Averaging Period	ESL (µg/m³)	Maximum Modeled Concentration (µg/m³)	ESL Exceedance (Yes/No)
Condensate /Crude	64741-47-5	Hourly	3500	655.53	No
		Annual	350	6.10	No

1.2 DESCRIPTION OF MODELING PROCEDURES

In order to perform a comprehensive NEPA air quality impacts analysis, and in the absence of detailed modeling procedures promulgated by MARAD, TGTI has incorporated several guidelines from modeling analyses performed in the Western Gulf of Mexico (GOM) in support of offshore operations authorized by BOEM, formerly known as U.S. Minerals Management Service (MMS). BOEM has developed air dispersion modeling exemption criteria for offshore operations based on the projected highest annual emissions and the distance of the facility to the closest onshore area [30 CFR Part 550.303(d)].

The Offshore and Coastal Dispersion (OCD) has been recommended as one of the dispersion models for use by the BOEM for emissions located on the Outer Continental Shelf (OCS). Although, the proposed project location is not in the outer OCS, the modeling analyses have been completed in a manner that conforms to the applicable rules and requirements for dispersion modeling as specified in 30 CFR Part 550 for consistency with modeling analyses in the Western GOM. Trinity has utilized the OCD model since it is on the US EPA's list of preferred dispersion models[5]. Note that other popular dispersion models such as AERMOD and CALPUFF were initially considered for this analysis. However, eventually TGTI chose the OCD dispersion model[6] because AERMOD is not yet considered suitable for predicting overwater model characteristics, and CALPUFF is not on the list of EPA's preferred dispersion models.

TGTI is utilizing recent BOEM guidance[7] on comparison of project modeled concentrations and the nearest representative background monitor concentrations to the corresponding NAAQS standard if the modeled concentrations are above the corresponding significant impact levels (SILs). On behalf of TGTI, Trinity Consultants (Trinity) has developed this NEPA air quality analysis in support of this DWP application. The following sections describe some of the analysis procedures incorporated by TGTI for this air quality analysis.

[5] https://www.epa.gov/scram/air-quality-dispersion-modeling-preferred-and-recommended-models
[6] The application of the OCD dispersion model was also discussed during a preliminary modeling discussion between Mr. Shreyas Erapalli (Trinity) and Ms. Ashley Mohr (EPA Region 6) on March 23, 2018.
[7] https://www.boem.gov/Dispersion-Modeling-Guidelines/

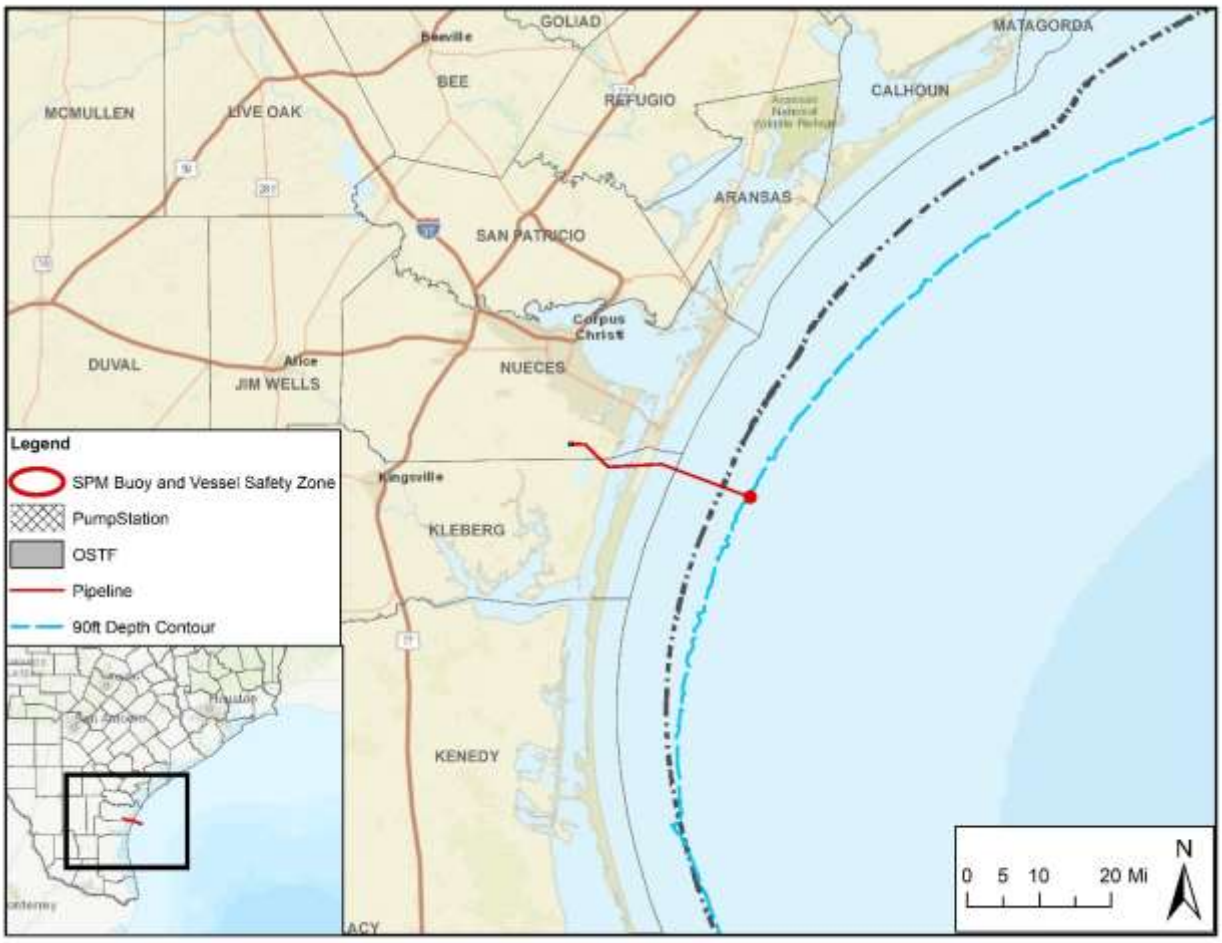
1.2.1 Significance Analysis

Although the proposed project will not trigger prevention of significant deterioration (PSD) permitting requirements for any modeled pollutants, TGTI has performed a Significance Analysis using the typical framework involved in PSD modeling scenarios for conservatism. The emissions of NO_X, CO, PM_{10}, $PM_{2.5}$, and SO_2 from the proposed project are being evaluated to determine whether they have the potential for a significant impact on the area surrounding the SPM buoy system.

The first step as part of this analysis is to conduct a preliminary impact determination. This step considers the emissions from the primary SPM buoy system (direct impact) and support vessel/carrier emissions (indirect/cumulative impact). The modeled ground-level concentrations at the shoreline are compared to the corresponding SIL, also referred to as NAAQS *de minimis* levels, to determine whether any modeled ground-level concentrations at any receptor locations are greater than the SIL (i.e., "significant" receptors). For pollutants that do not make a significant impact, meaning predicted high concentrations do not exceed the SIL, the compliance demonstration is complete. If there is a significant impact, further analysis typically deemed necessary.

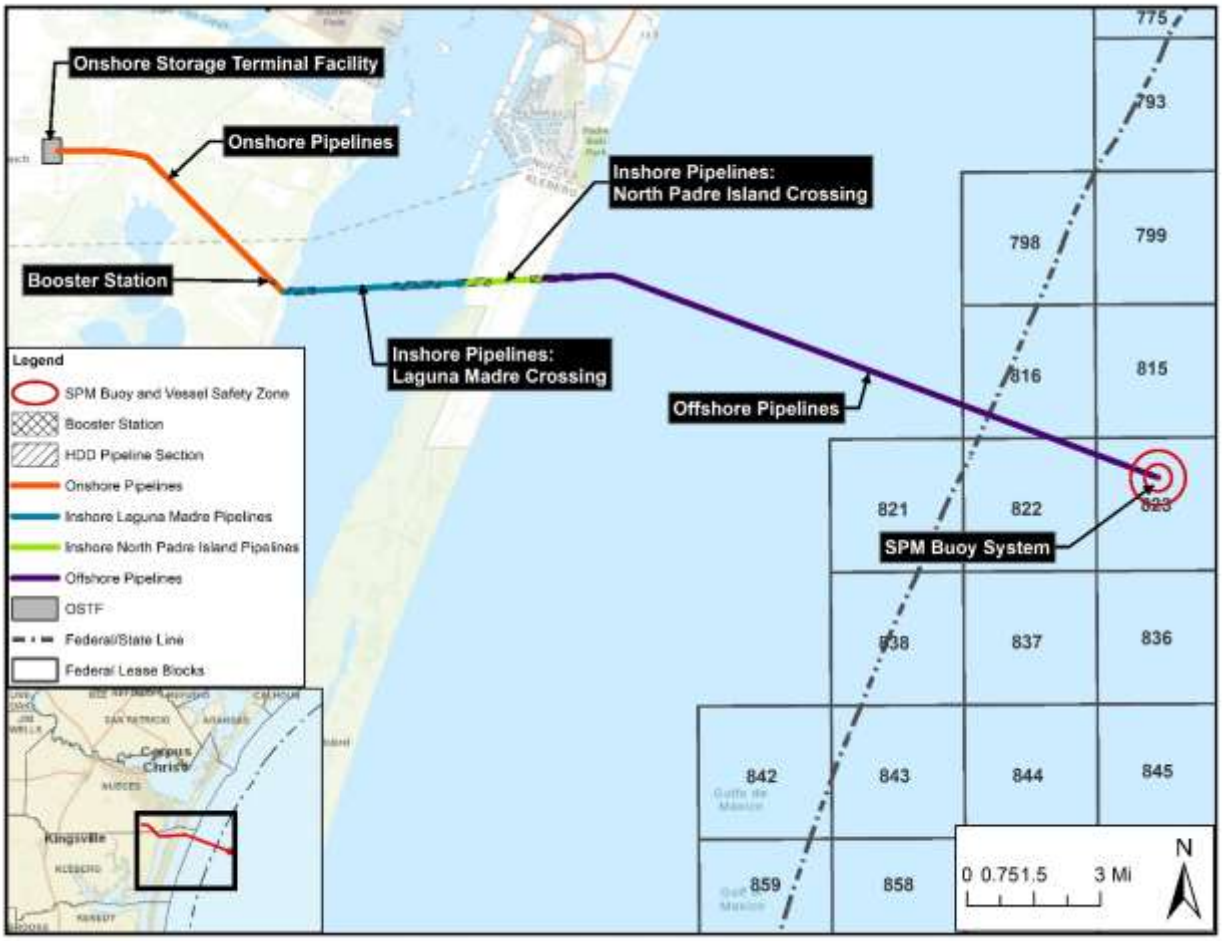
The SILs and their corresponding averaging periods are summarized for each of the evaluated pollutants in Table 1-1. Note that the $PM_{2.5}$ SIL justification is addressed in Section 1.2.2. For this project, it is anticipated that SO_2, CO, PM_{10}, and $PM_{2.5}$ emissions will not require full impacts modeling. Further analysis for NO_2 is included to incorporate the combined impact from the project emissions and the regional background concentration to compare to the NAAQS, as discussed further in Section 4.2.

Figure 2-1: Vicinity Map



Crude oil/condensate will be loaded onto Very Large Crude Carriers (VLCC)/Ultra Large Crude Carriers (VLCC) moored near the SPM buoy system. The crude oil/condensate to be loaded will be supplied from the Onshore Storage Terminal Facility (OSTF), through the proposed pipeline infrastructure, and to the DWP. Each of the two (2) 30- inch-diameter pipelines will be capable of 30,000 bph flow rate allowing an overall system crude oil delivery capacity of 60,000 bph to vessels moored at the proposed DWP. Vessels will be moored to the proposed SPM buoy system via mooring hawsers. Crude oil will be routed from subsea PLEM via two 24-inch ID flexible hoses to SPM buoy. Floating hoses will extend from the SPM buoy system to the moored vessel to allow for the loading of crude oil. The project will have a crude oil/condensate loading capacity of 60,000 bph and 216 million barrels per year. The project will be able to load up to 96 large vessels per year. The overview map (Figure 2-2) shows the SPM buoy system location and the pipeline network for the Project.

Figure 2-2: Overview Map



3. MODEL INPUT PARAMETERS

3.1 DESCRIPTION OF PROPOSED SOURCES

Currently, the exact configuration of the SPM buoy system, the type of support vessel and crude tanker specifications have not yet been finalized. Therefore, Trinity has performed the air dispersion modeling analysis using representative emissions and stack parameters information for similar equipment and combustion sources used on other ocean tankers, platforms, or drill ships. For evaluating the indirect or cumulative impacts from the Project (when engaged by TGTI in the safety zone), this dispersion modeling analysis assumes that the support vessel sources are stationary sources for the purpose of this analysis.

The sources of emissions on the support vessels and crude tanker will primarily consist of diesel-fired internal combustion engines and boilers. The air dispersion model includes following sources in service:

- Two pilot boats;
- One tug boat with a main engine and an auxiliary engine;
- One helicopter;
- Marine loading emissions; and
- A crude oil tanker which will contain several additional equipment
  - primary drive engine(s), or main engine(s);
  - auxiliary engine(s)
  - carrier boiler(s),
  - crane engine(s),
  - cargo pump(s),
  - ballast pump(s),
  - stripping pump(s), etc.)

3.2 POTENTIAL EMISSIONS

TGTI estimated the potential annual emissions from emission sources associated with the SPM buoy system operations (including indirect impacts from the carrier itself and other emissions sources on the carrier) at the proposed worst-case location. The estimated potential hourly emissions from these sources have been utilized for the short-term averaging period models in this dispersion modeling analysis. Please note that this modeling approach results in conservative estimates of modeling impacts, especially for averaging periods other than the 1-hour averaging period (i.e. 8 hour, and 24 hour averaging period models). The annual emissions from the Project have been utilized to model the annual averaging periods.

As discussed in the following sections of this report, the dispersion modeling for this project was conducted in a manner that utilizes the worst-case ambient and operating conditions in an effort to predict the highest impact for each averaging period. For instance, if the predicted maximum impacts due to the hourly emissions are below the air quality standards, no additional analyses are deemed necessary for that pollutant's averaging period.

Please note that PM_{10} emissions rates have been utilized to model all particulate matter ($PM_{10/2.5}$) concentrations. The $PM_{2.5}$ 24-hr SIL is 1.2 μg/m^3, and the PM_{10} 24-hr SIL is 5.0 μg/m^3. Since the same set of emissions sources emit $PM_{2.5}$ and PM_{10} in this analysis, PM_{10} modeling impacts are also considered to be insignificant, if the $PM_{2.5}$ impacts are insignificant (i.e., if $PM_{2.5}$ modeled impacts < 1.2 μg/m^3, then the

same magnitude of emissions as PM_{10} should be < 5.0 μg/m^3). Modeled input emission rates (in grams/second) have been calculated based on the potential maximum hourly emission rate of each source for the short-term averaging periods, and the annualized emissions of each source for the annual averaging period. The air quality support application in Appendix A presents a summary of the potential-to-emit emissions from the proposed operations for any given year. Tables 3-1 and 3-2 show the model input emission rates for the proposed sources of air pollution.

Sample calculation for Crude Tanker (Model ID – CTME) maximum hourly emissions (g/s):

NO_X emissions (g/s) = Maximum Hourly NO_X emissions (lb/hr)* 453.592 gms/1 lb *1 hr/3,600 seconds

= 315.98 lb/hr*453.592 gms/1 lb * 1 hr/3,600 seconds

= 39.8129 grams/second

Table 3-1. Hourly Modeled Emission Rates

Model ID	Source Description	CO (lb/hr)	SO_2 (lb/hr)	NO_2 (lb/hr)	$PM_{10}/PM_{2.5}$ (lb/hr)[9]	VOC (lb/hr)
CTME	Crude Tanker[10]	110.37	32.85	642.65	21.05	15.49
TBME	Tug Boats – Main Engine	79.20	10.77	185.78	5.78	9.24
TBAE	Tug Boats – Auxiliary Engine	1.97	0.18	2.60	0.12	0.60
PBME	Pilot Boat – Main Engine	8.25	1.12	4.96	0.60	0.96
HME	Helicopter - Main Engine	2.67	0.15	0.98	0.03	2.01
LML	Marine Loading	-	-	-	-	7,773.68
Total		**202.46**	**45.07**	**836.97**	**27.58**	**7,801.98**

Table 3-2. Annualized Modeled Emission Rates

Model ID	Source Description	CO (tpy)	SO_2 (tpy)	NO_2 (tpy)	$PM_{10}/PM_{2.5}$ (tpy)	VOC (tpy)
CTME	Crude Tanker	254.30	75.69	1,480.68	48.50	35.79
TBME	Tug Boats – Main Engine	78.14	10.62	183.29	5.70	9.11
TBAE	Tug Boats – Auxiliary Engine	3.55	0.32	4.69	0.21	1.09
PBME	Pilot Boat – Main Engine	7.13	0.97	4.28	0.52	0.83
HME	Helicopter - Main Engine	0.14	0.01	0.05	0.002	0.10
LML	Marine Loading	-	-	-	-	10,808
Total		**343.3**	**87.6**	**1673.0**	**54.9**	**10,855**

[9] Note that for the purpose of this modeling analysis $PM_{2.5}$ hourly and annual emissions have conservatively been assumed to be equal to the corresponding PM_{10} emissions. However, the detailed emissions calculations include emissions estimates for both pollutants.

[10] Crude Tanker emissions also include emissions from the main and auxiliary engines, crane engines, cargo pumps, ballast pumps, stripping pumps, and carrier boiler.

3.3 MODELED PARAMETERS

The SPM location coordinates have been estimated to be the worst-case modeling location based on the distance of the SPM buoy system to the shoreline. To represent the worst-case scenario, the NEPA modeling analysis was performed assuming the SPM buoy system and associated supply vessels will be located at 27.482596 latitude degrees, -97.015256 degrees longitude.

For dispersion modeling purposes, emissions from the support vessels were modeled using representative support vessel stack parameters for similar modeling projects in the Gulf of Mexico. Consistent with previously approved modeling analyses for OCS sources by EPA Region 4 and/or BOEM, the proposed emissions from the main engines and auxiliary equipment on the crude tanker are modeled assuming that the total emissions are released from the main engine stack. Given the relative proximity of emission sources to one another when compared to the distances to the nearest onshore areas, and considering that the stack parameters for the largest emissions sources will be used as model inputs, the modeled impacts predicted using this approach are expected to be more conservative. It is assumed that there are no buildings or structures influencing downwash for the SPM buoy system. This is consistent with recent offshore modeling analyses submitted to other EPA Regions and BOEM since the ratio of the distance between stacks/structures to the distance of the SPM buoy system to the shoreline receptors is much less than 1. The modeled source stack parameters are presented in Table 3-3.

Table 3-3. Modeled Source Stack Parameters

Model ID	X (km)	Y (km)	Stack Height* (m)	Stack Gas Temp. (K)	Stack Dia. (m)	Stack Exit Vel. (m/s)	Stack Angle (°)
CTME	86.474	109.925	27.62	613	1.00	12.74	0
TBME			15.54	450	0.48	1.41	0
TBAE			15.54	450	0.48	1.41	0
PBME			3.05	642.04	0.15	0.001	0
HME			6.67	533	0.001	0.001	0
LML			36.58	508.15	1.42	15.24	0

* The stack height represents the height above the sea level (water line).

Additionally, Figure 3-1 shows the source and receptor locations for this modeling analysis. The receptors have been placed across the Texas shoreline closest to the SPM buoy system, as discussed in Section 4.

Figure 3-1. Receptor and Source Locations

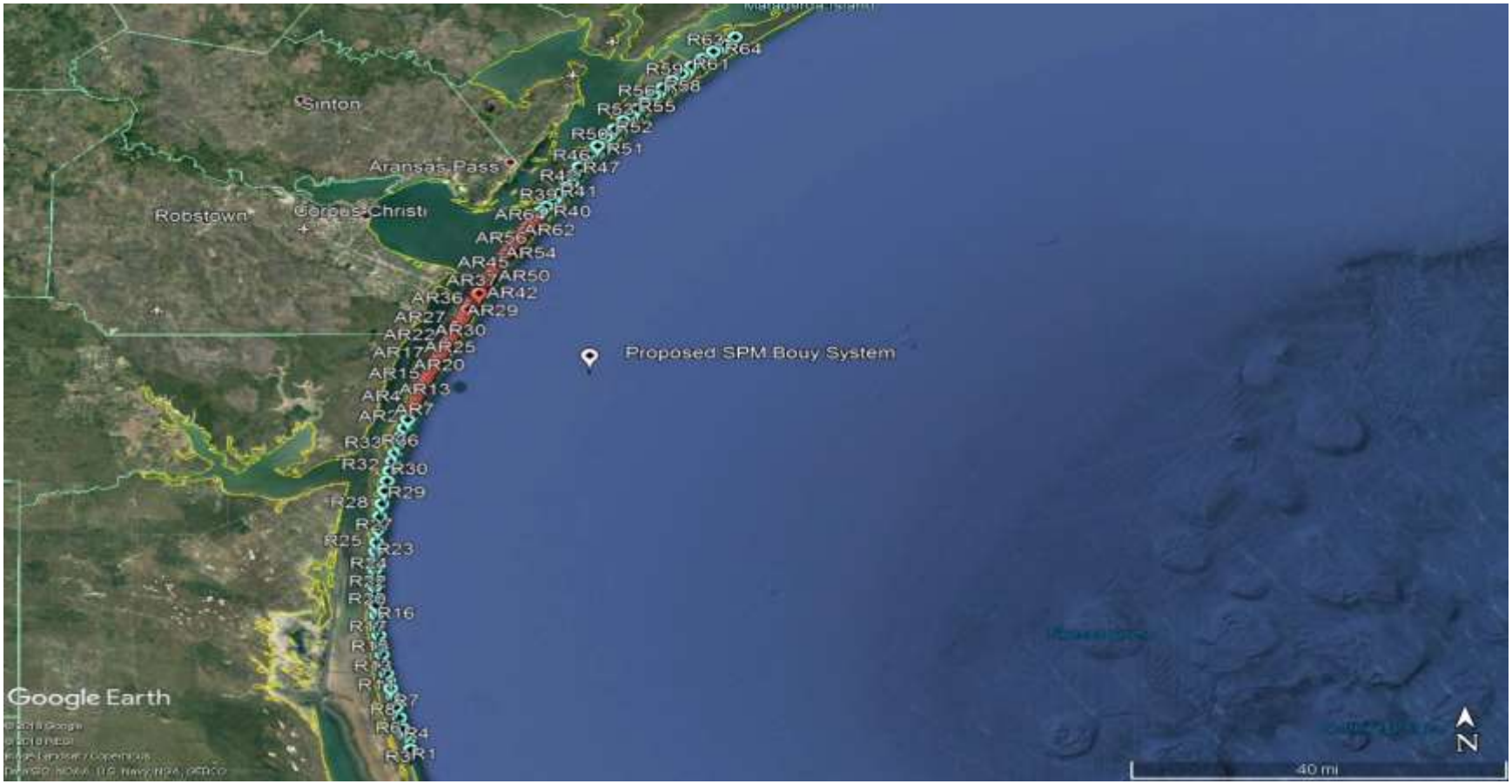


Figure 2-1. Receptor and Source Locations	Trinity Consultants	**Texas Gulf Terminals Inc.**
Fine Grid Receptors	**Discrete Receptors**	**Modeled Sources**

4.1 METEOROLOGICAL DATA

The OCD model requires both over-land and over-water meteorological data. The following meteorological datasets have been used for the air quality modeling analyses to determine the proposed project impacts on the onshore receptors:

- Water temperature, over-water air temperature, over-water dew point temperature, over-water wind speed, and over-water wind direction from Station 42020 – Foam Buoy, SCOOP Payload, an off-shore buoy operated by the National Data Buoy Center (NDBC).
- Over-land surface observations of key meteorological variables from the Corpus Christi National Weather Service (NWS) station since it is the closest surface meteorological station.
- Upper air observations of key meteorological variables also from the Corpus Christi NWS station, since it is the closest upper air meteorological station.

The datasets presented above have been selected in accordance with Section 4.1 of the MMS guidance titled *"Five-Year Meteorological Datasets for CALMET/CALPUFF and OCD5 Modeling of the Gulf of Mexico Region (July 2008)"*.

TGTI has utilized five consecutive years of meteorological data from 2000-2004 in this air quality modeling analysis. The over-water and over-land meteorological datasets for the stations proposed above for these five years have been found to be most complete sets of meteorological data when compared to other stations. Model runs have been performed using over-water mixing heights of 500m meters for five years.[11] Over-land meteorological data was processed using the U.S. EPA's Meteorological Preprocessor for Regulatory Models (MPRM).

4.2 AIR QUALITY MODEL

The latest version of the OCD Model (Version 5.0, dated 5/16/2005) was used to assess the impacts of the SPM operation emissions along the Texas shoreline. Although OCD is on the list of preferred EPA models, it is not used as commonly as AERMOD or CALPUFF, therefore TGTI has included the following figures to illustrate the various options in OCD's graphical user interface (GUI).

[11] Based on the raw meteorological files obtained by Trinity from BOEM.

Figure 4-1. OCD Home Menu

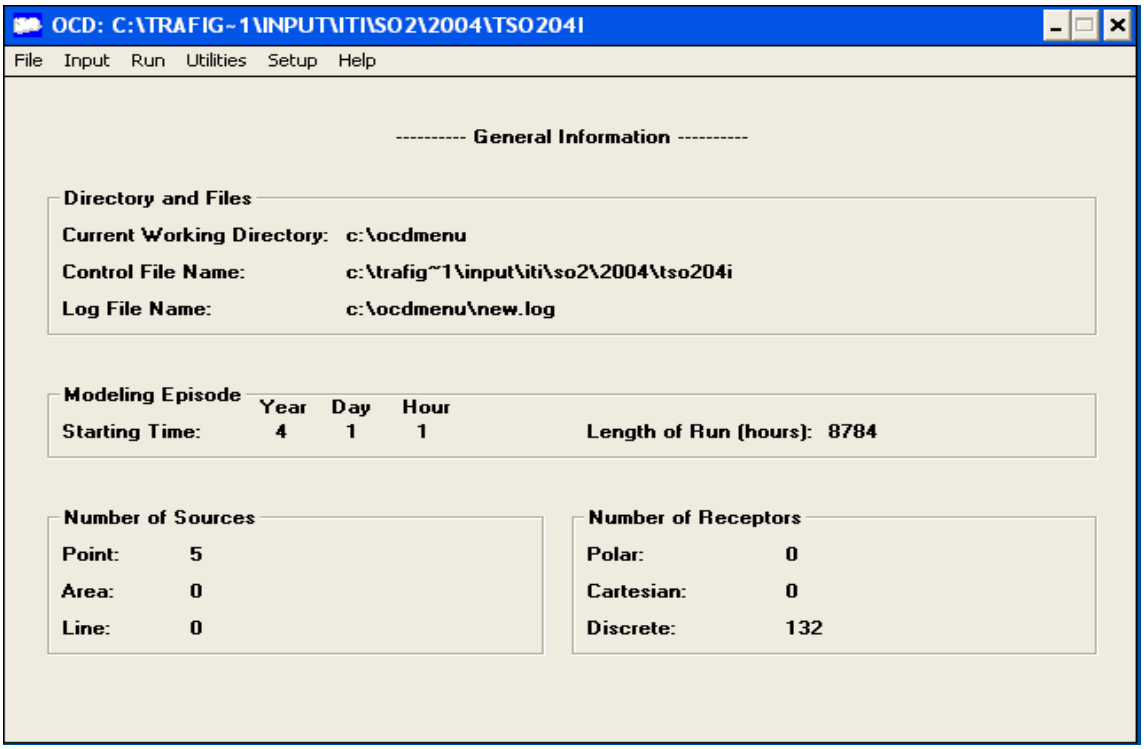


Figure 4-2. OCD Input and Run Information

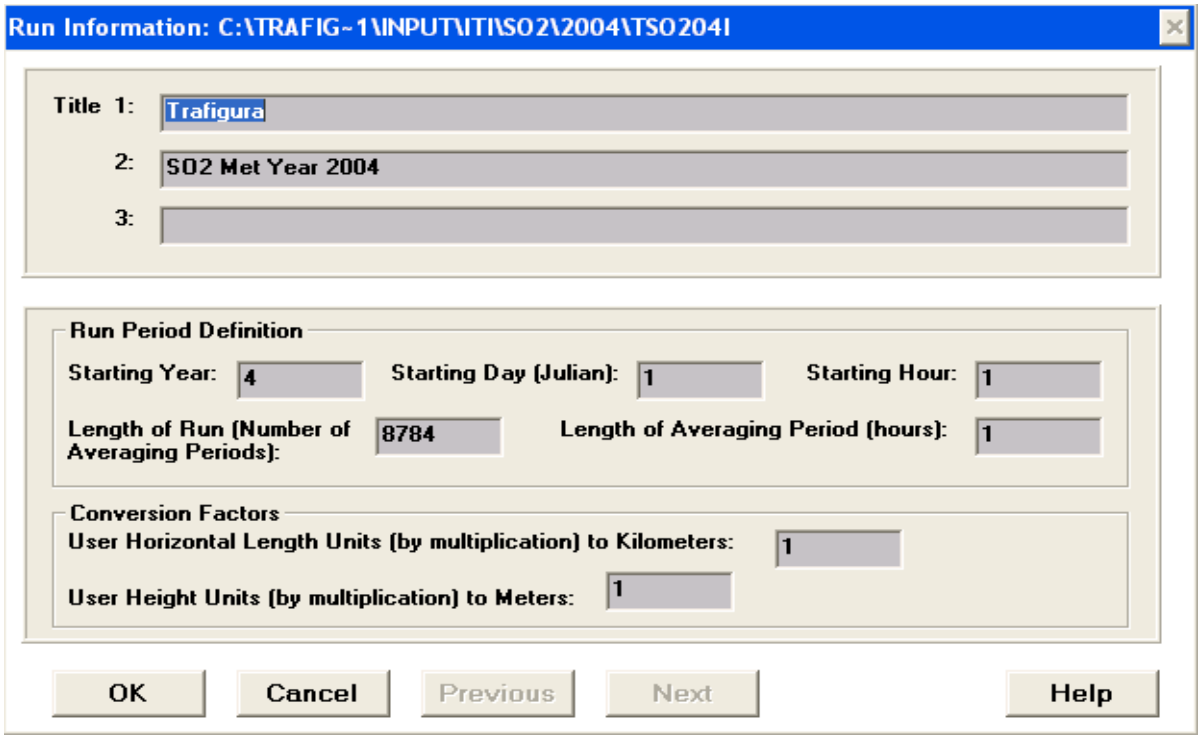


Figure 4-3. OCD Model Domain Limits for Different Regions

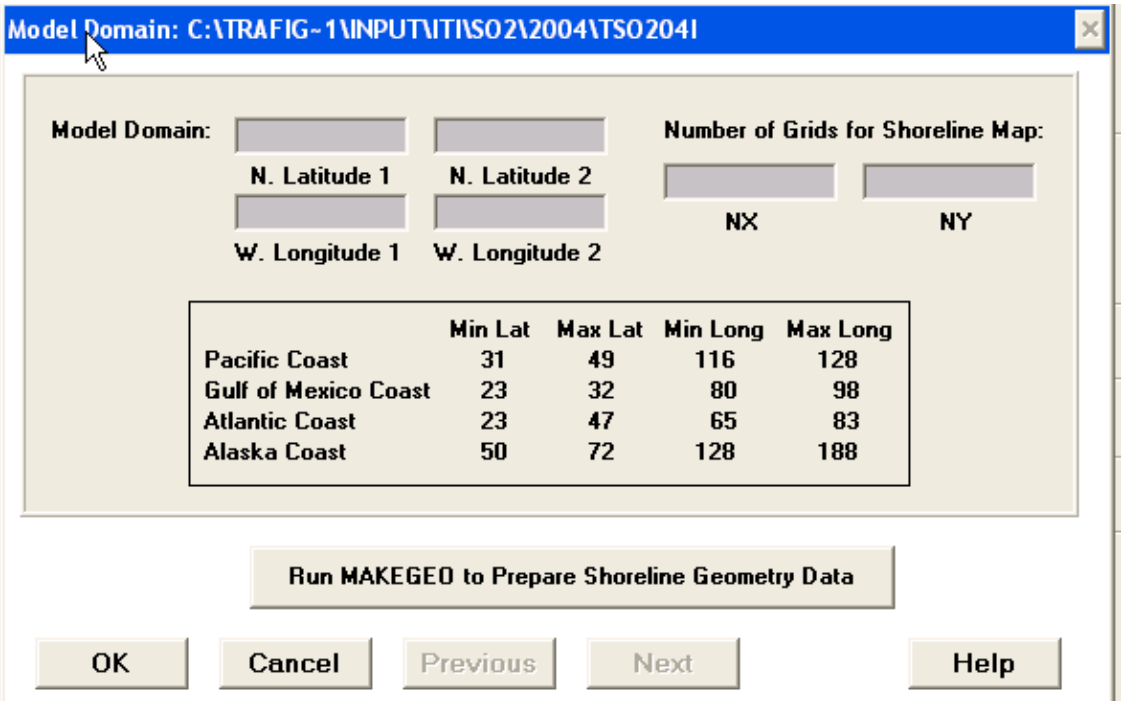


Figure 4-4. OCD Source Types and Pollutant Information

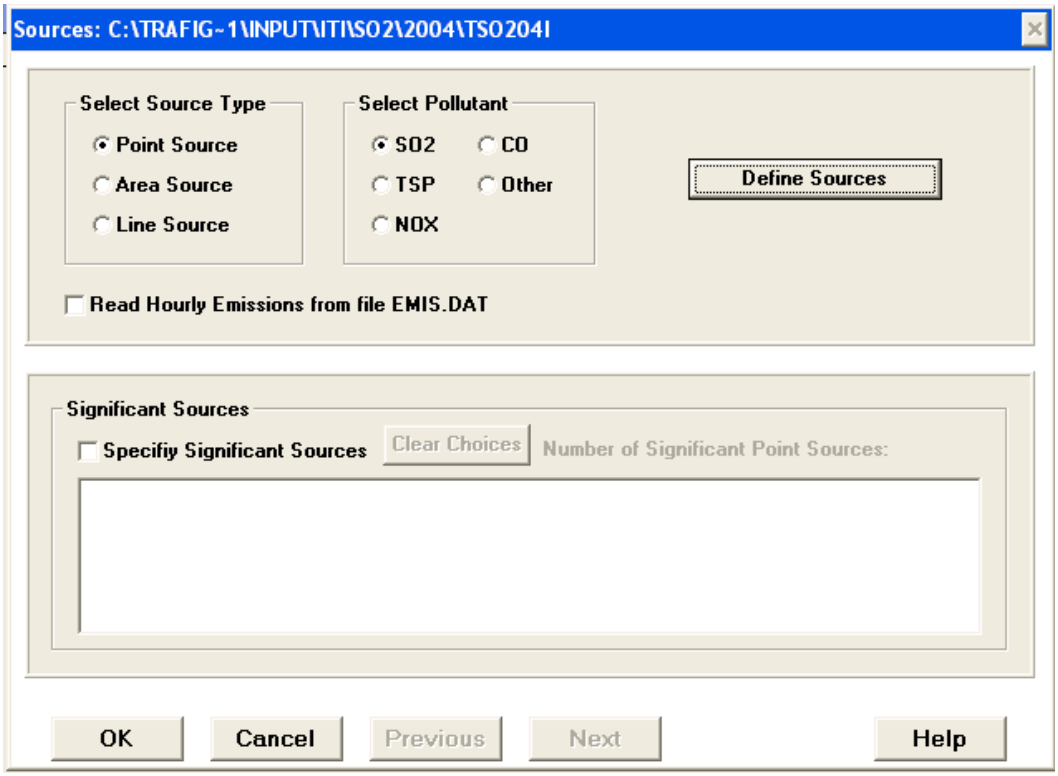


Figure 4-5. OCD Emissions Source and Stack Information

Point Sources: C:\TRAFIG~1\INPUT\ITI\SO2\2004\TSO204I

Total Number of Sources: 5

Source Name	X Coordinate (user units)	Y Coordinate (user units)	Pollutant Emission Rate (g/s)	Ht of Building (m)	Ht of St (r
CTME	86.474	109.925	0.2722	0	27.
TBME	86.474	109.925	0.3128	0	15.
TBAE	86.474	109.925	0.0093	0	15.
PBME	86.474	109.925	0.0279	0	3.
HME	86.474	109.925	0.0002	0	6.

Point Sources: C:\TRAFIG~1\INPUT\ITI\SO2\2004\TSO204I

Total Number of Sources: 5

Ht of Stack-Top (m)	Stack Gas Temp (deg K)	Stack-Top Inside Diameter (m)	Stack Gas Exit Velocity (m/s)	Deviation of Stack Angle (deg)	Eleva (m
27.62	613	1	12.74	0	0
15.54	450	0.48	1.41	0	0
15.54	450	0.48	1.41	0	0
3.05	642.04	0.15	0.001	0	0
6.67	533	0.001	0.001	0	0

Figure 4-6. OCD Discrete Receptor Information

Discrete Receptors: C:\TRAFIG~1\INPUT\ITI\SO2\2004\TSO204I

Discrete Receptor Definition:

Total Number of Discrete Receptors: 132

Receptor Name	X Coordinate (user units)	Y Coordinate (user units)	Height Above Ground (m)	Ground Elevation (m)	Terrain Elevatio (m)
R1	57.684	21.396	0	0	0
R2	57.226	22.952	0	0	0
R3	56.766	24.494	0	0	0
R4	56.325	26.04	0	0	0
R5	55.69	28.478	0	0	0
R6	55.093	30.923	0	0	0
R7	54.531	33.374	0	0	0
R8	54.149	35.05	0	0	0
R9	53.788	36.727	0	0	0
R10	53.435	38.409	0	0	0
R11	53.02	40.549	0	0	0
R12	52.631	42.687	0	0	0

Figure 4-7. OCD Meteorological Data Options

Meteorological Data Options: C:\TRAFIG~1\INPUT\ITI\SO2\2004\TSO204I

Meteorological Data Options

- [ ] Do Not Modify Wind Speed for Land Source
- [x] Overwater Wind Direction Provided
- [x] Overwater Wind Speed Provided
- [ ] Overwater Vertical Potential Temp Data (deg K/m) Provided
- [ ] Overland Horizontal and Vertical Turbulence Intensity Data Provided
- [ ] Overwater Wind Direction Shear (deg/m) Provided

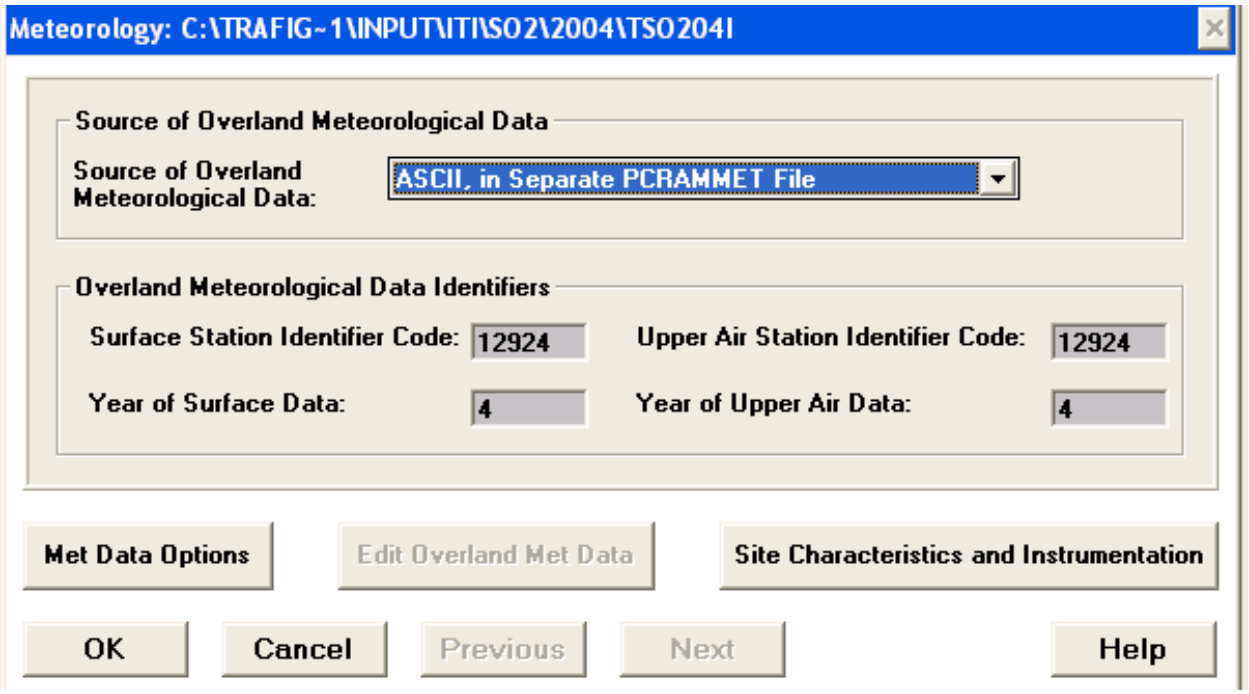
Overwater Humidity Specified As: Relative Humidity (%)

Water Surface Temperature Specified As: Air Minus Water Temperature (deg K)

- [ ] Overwater Horizonal Turbulence Intensity Data Provided
- [ ] Overwater Vertical Turbulence Intensity Data Provided

OK Cancel Help

Figure 4-8. OCD Meteorological Station Characteristics



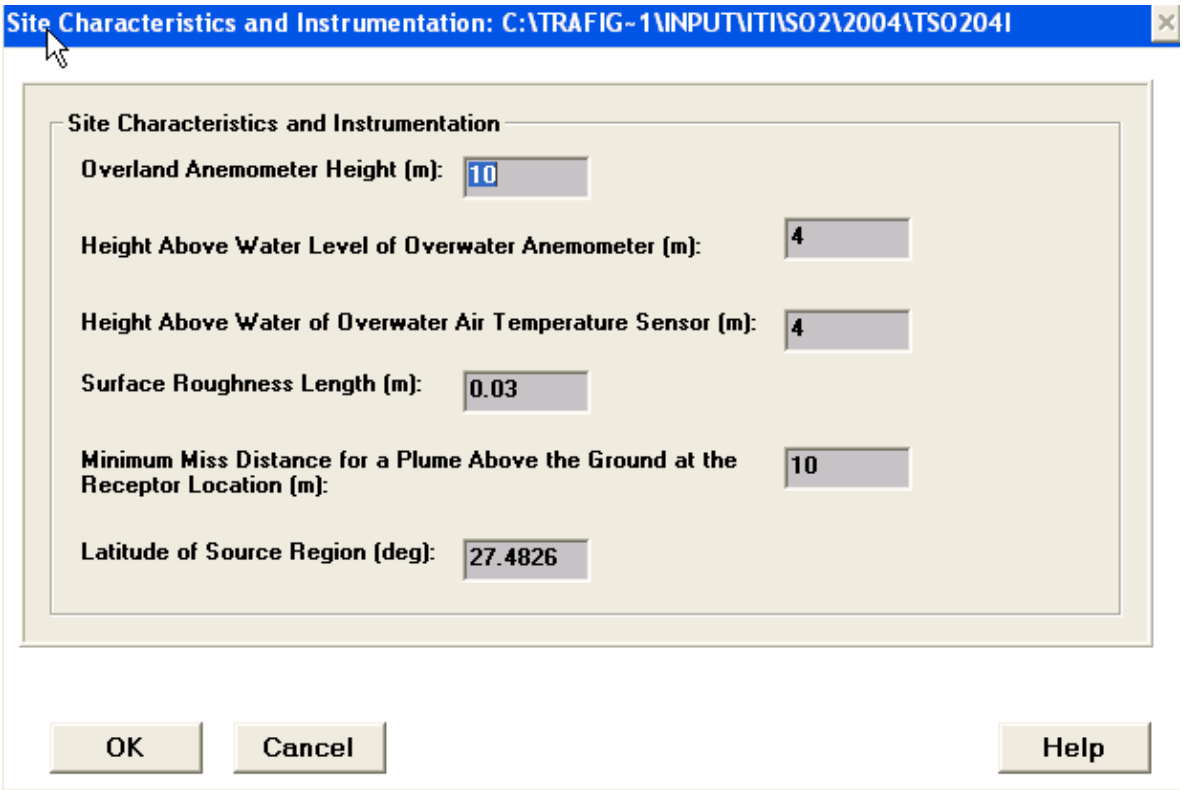
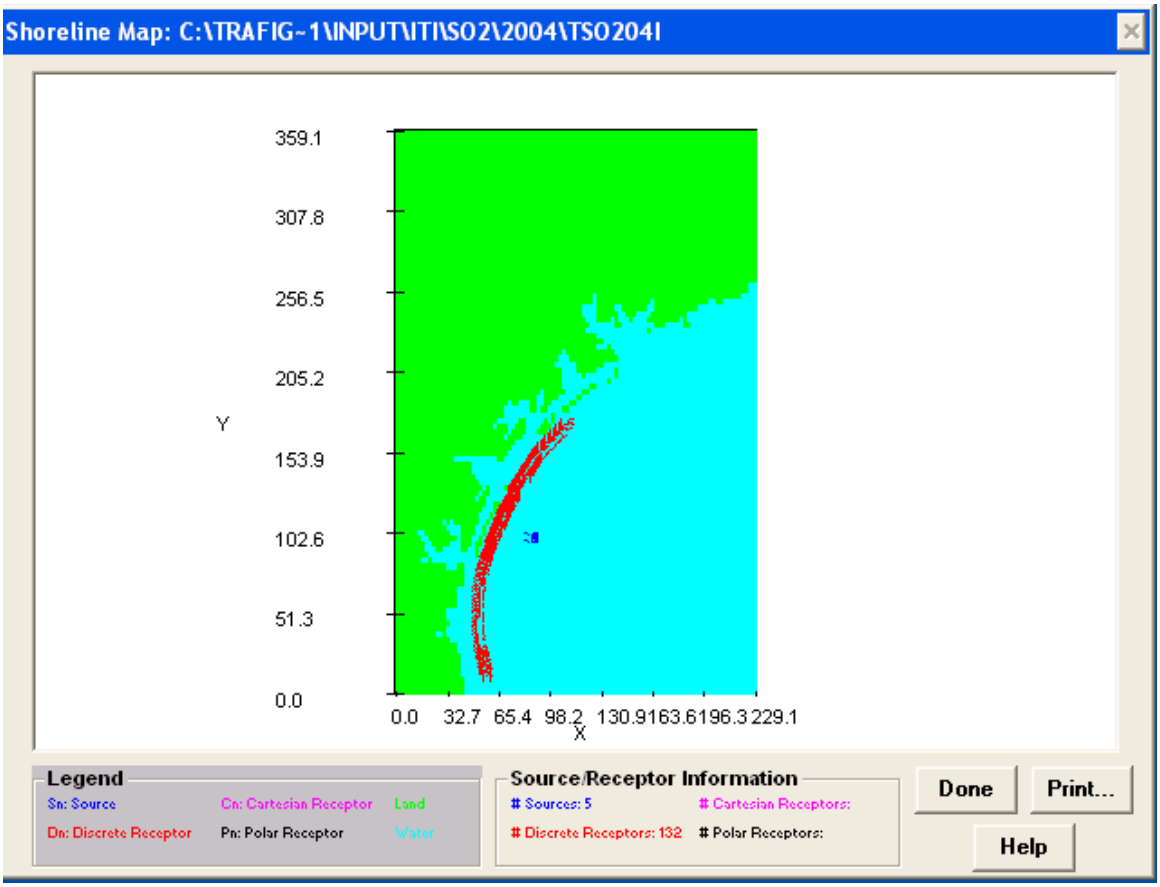


Figure 4-9. OCD Map Overview



4.3 SPECIAL CONSIDERATION FOR NO_2

The objective of the modeling analysis was to determine if the impacts from the proposed SPM operations exceed the NAAQS outlined in Table 1-1.

In the "Models for Nitrogen Dioxide" section of the Guideline (Section 5.2.4),[12] the U.S. EPA recommends a tiered screening approach for estimating annual NO_2 impacts from point sources. On December 20, 2016, the Administrator signed a final rule that revises the Guideline on Air Quality Models. Since the revised Guideline did not specifically address recommended modeling methodologies for the 1-hour NO_2 NAAQS analysis, the approaches identified for the annual standard were also applied to the new 1-hour standard.

Consistent with prior dispersion modeling analyses, under the initial and most conservative Tier 1 screening level, all NO_X emitted is modeled as NO_2, i.e., total conversion of NO (the primary chemical form of NO_X) to NO_2 is assumed. If the impacts predicted using this approach result in exceedances of the NAAQS, a more refined technique could be used. In the current modeling analysis, Trinity assumes that all NO_X emitted is modeled as NO_2.

TGTI took the 2 step approach in comparing the model results to the NAAQS. In Step 1, the model results were compared to the SILs set by the EPA for each criteria pollutant. If the modeled concentrations exceeded the respective SILs, TGTI compared the modeled concentrations to the NAAQS with the addition of a representative background monitoring concentration. This procedure was based on similar recent submittals to BOEM for authorization to operate in the western GOM. BOEM has approved this modeling methodology based on the interim nature of some of the SILs as discussed below.

On February 9, 2010, the U.S. Environmental Protection Agency (EPA) established a new 1-hour NAAQS for NO_2.[13] In that rulemaking, EPA established the 1-hour NO_2 standard at a level of 100 ppb, based on the 3-year average of the 98th percentile of the yearly distribution of 1-hour daily maximum concentrations. However, the final rules promulgating the 1-hour NO_2 NAAQS did not include significance levels for the 1-hour averaging period. Therefore, on June 29, 2010, EPA proposed an interim 1-hour SIL of 4 ppb for NO_2, for facilities to use as a screening tool for completing the required air quality analyses for the new 1-hour NO_2 NAAQS.[14] This interim SIL is currently not included in 30 CFR 550.303(e).

If the modeling analysis indicates that the interim NO_2 1-hour SIL is exceeded, TGTI will determine whether the emissions from the proposed activities combined with the nearest representative onshore NO_2 monitor concentrations exceed the NO_2 1-hour NAAQS.[15] If the modeling analysis indicates that the emissions from the proposed activities combined with the nearest representative onshore NO_2 monitor concentrations do not exceed the NAAQS, the emissions will not be deemed to significantly affect the air quality of an onshore area or a State, per 30 CFR 550.303(f). As mentioned previously, this methodology has also been utilized for other criteria pollutants evaluated in this PSD analysis. Applicable SIL and NAAQS are listed in Table 3-1.

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[12] U.S. EPA: Guideline on Air Quality Models, 40 CFR Part 51 – Appendix W (Revised July 29, 2015), referred here as "Guideline".
and Incorporation of Approaches to Address Ozone and Fine Particulate Matter, 40 CFR Part 51 - Appendix W (Revised, January 17, 2017), referred here as "Guideline".
[13] See 75 Red. Reg. 6474 and 75 Fed. Reg. 35520.
[14] Based on U.S. EPA Memorandum from Stephen D. Page to Regional Air Division Directors titled, "Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program," June 29, 2010.
[15] Based on the BOEM's current guidelines titled "BOEM's GOMR Dispersion Modeling Guidelines July 2015".

Typically, an exceedance of the annual NO_X SIL, which is defined in 30 CFR § 550.303(e) as 1 μg/m^3, requires the application of Best Available Control Technology (BACT), pursuant to 30 CFR § 550.303(h). BOEM's regulations do not allow for the annual NO_x SIL to be exceeded without the application of BACT, regardless of the impact on the NAAQS annual NO_x standard. However, Trinity believes that due to the conservatism built into the modeled emissions, as well as the "indirect" nature of the emissions from support vessels and crude tanker, the NO_2 annual impacts are over predicted. Also, please note that the model assumes full conversion of NO_X to NO_2 (i.e. NOx = NO_2), which adds to the conservatism built into this model. As per US EPA's latest Appendix W guidelines, the maximum NOx to NO_2 conversion that can occur (i.e. in worst-case scenario) is 0.9 (i.e. 90%) with the typical range being in between 0.2-0.9. However, as mentioned earlier, in order to maintain a conservative approach, Trinity assumes that all NO_X emitted is modeled as NO_2.

4.4 RECEPTOR LOCATIONS AND LAND-MASS CONFIGURATION

Consistent with the BOEM Guidelines, 132 discrete receptors spaced three miles apart have been placed along the Texas (Gulf Coast) shoreline closest to the location of the SPM operations as shown in Figure 2.1.[17] In order to be consistent with prior submittals for similar modeling analysis, TGTI added a few fine grid receptors at approximate 1 to 2 km spacing between the discrete receptors as shown in Figure 3-1, to add to the conservatism built into the dispersion modeling analysis. This methodology has been approved for modeling in the western GOM during prior submittals by BOEM. Therefore, the modeling analysis was performed using this receptor grid placement technique.

4.5 MODEL OPTIONS

All sources modeled in this analysis are considered to be point sources as shown in Figure 3-1. Because the Gulf Coast area of concern is situated at sea level, terrain features have not been considered (i.e., simple terrain only).

4.6 TERRAIN PROCESSING FOR CLASS II ANALYSIS

As the proposed OCS source is located in the GOM and corresponding Class II receptors will be along the state shoreline, the entire modeling domain will be located completely over water in the Gulf of Mexico. Therefore, all modeled sources and Class II receptors are assumed to be situated at sea level and the elevations for off-property sources and receptors will be set to zero for the Class II modeling analysis.

4.7 BUILDING DOWNWASH

Building downwash accounts for the effects of nearby structures on the flow of emissions from their respective release structures. For this modeling analysis, it is assumed there will be no building structures within the modeling domain, therefore, the building downwash will not be enabled.[18]

4.8 NO_2 BACKGROUND CONCENTRATIONS

TGTI selected the Channelview Monitor, EPA Site Number 48-201-0026, located in Harris County near Houston, Texas as the conservative/representative monitor for the SPM buoy system for NO_2 background concentrations due to the following:

- This monitor samples for NO_2 and is located in the gulf coast area like the proposed SPM buoy system and model receptor locations.
- As illustrated in Figure 4-10, the area directly surrounding the Channelview Monitor is primarily urban and includes industrial, commercial, and residential areas. Figure 4-10 also shows that the nearby area contains a large number of NO_X emitting industrial sources. Additionally, the monitor is in the Houston metropolitan area, a dense residential, commercial, and industrial urban area. Conversely, the SPM buoy system is located near Corpus Christi, Texas which is a much smaller urban area compared to Houston, Texas. Figure 4-10 presents a visual comparison of the areas surrounding the Corpus Christi Waterfront Terminal and Channelview Monitor location. The yellow circles on these aerial images indicate the 10-km radius surrounding a representative area of Corpus Christi and the chosen monitor, and the red points indicate nearby industrial sources according to TCEQ 2015 Emission Inventory (EI) database.
- Table 4-1 provides a summary of the emissions from industrial sources reporting NO_X emissions located within 10 km of the Channelview Monitor and the representative Corpus Christi on-

[17] Based on the BOEM's current guidelines titled "BOEM's GOMR Dispersion Modeling Guidelines January 2018".

[18] Per guidance provided on Pg. 45 of the VISTAS, *Protocol for the Application of the CALPUFF Model for Analyses of Best Available Retrofit Technology (BART)*, December 22, 2005, revised August 31, 2006.

shore area based on TCEQ 2015 EI data. Table 4-2 and Table 4-3 provide the emission rates for each of the sources shown in Figure 4-10 within 10 km of the Channelview Monitor and the Corpus Christi on-shore area based on TCEQ 2015 EI data. The NO_X emissions surrounding the Channelview Monitor are about 1.2 times greater than those around the Corpus Christi on-shore area. In addition, there are more residential and commercial sources within 10 km of the Channelview Monitor. Therefore, the NO_2 concentrations from this monitor conservatively represent more residential, commercial, and industrial activity than the on-shore area of Corpus Christi.

- Table 4-4 presents the total population of each county (i.e., Harris County and Nueces County) alongside total NO_X emissions from each county obtained from the TCEQ 2015 EI data. The population in Harris County is more than 12 times greater than the population in Nueces County, and the NO_X emissions from emission sources in Harris County are 2.2 times greater than those in Nueces County. This population and emissions data, along with Figure 4-10, clearly indicate that the area surrounding the Channelview Monitor is more densely populated and more developed than the area surrounding the on-shore Corpus Christi area. Therefore, the NO_2 concentrations from the monitor in Harris County conservatively represent more commercial, industrial, and residential activity than the area of the chosen representative area of Corpus Christi in Nueces County.
- As shown in Table 4-5, a complete year (i.e., at least 75% of the sampling days for each quarter are valid) of NO_2 concentration data for the Channelview Monitor site are available for each of the following years: 2014, 2015, and 2016.

Based on the information above, TGTI believes the use of NO_2 concentrations from the Channelview Monitor are conservative and can adequately represent both off-property sources and background for the NAAQS demonstration.

Figure 4-20. NO_X Sources Reported in the TCEQ 2015 Emission Inventory within 10 km of the Channelview Monitor and the representative Corpus Christi Waterfront area

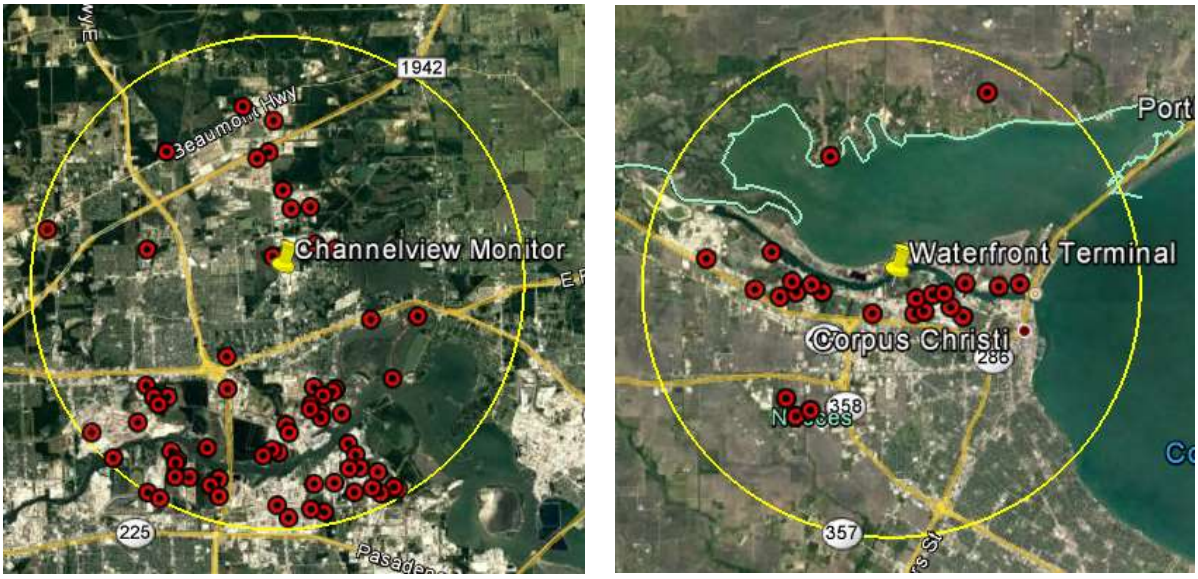

Table 4-1. Summary of Emissions for NO_X within 10 km of Monitor and Site Location

Location	Description	NO_X Annual Emission Rate [1] (tpy)
Channelview Monitor (EPA ID: 48-201-0026)	NO_2 Monitor	5,544.54
Corpus Christi Waterfront Area	On-shore Location in the vicinity of the SPM buoy system	4,461.08

[1] 2015 Emission Inventory Data, including coordinates used to determine distances, were provided via email by Mr. Adam Bullock, TCEQ, to Mr. Xu Liu, Trinity Consultants, on February 10, 2017.

Table 4-2. TCEQ 2015 Emission Inventory Data for NO_X Sources within 10 km of the Channelview Monitor

Facility Name	Distance from Monitor (km)	NO_X (tpy)
GALENA PARK TERMINAL	9.59	9.90
CHANNELVIEW COMPLEX	3.41	1173.64
LA PORTE PLANT	9.45	33.42
RAILCAR SERVICES CHANNELVIEW	3.54	0.74
DEER PARK PVC CAUSTIC PLANT HOUSTON	8.20	17.82
OXY VINYLS LAPORTE PLANT	9.63	83.50
BATTLEGROUND SITE	8.62	202.23
GREENS BAYOU PLANT	6.33	130.37
VOPAK DEER PARK FACILITY	7.60	0.00
ALBEMARLE CORP	8.29	27.34
PASADENA PLANT	8.54	10.42
JACINTOPORT PLANT	5.85	32.04
HOUSTON FUEL OIL TERMINAL	5.68	15.56
GREENS BAYOU ELECTRIC GENERATING STATION	9.55	66.38
DEER PARK TERMINAL	8.01	24.43
PRECOAT METALS HOUSTON	5.51	11.74
DEER PARK PLANT	9.19	48.51
MERISOL GREENS BAYOU PLANT	6.74	30.64
HOUSTON TERMINAL	6.68	13.91
PCI NITROGEN PASADENA FACILITY	9.65	17.56
ARKEMA	6.81	10.39
PASADENA PLASTICS COMPLEX	9.90	59.08
REICHHOLD REACTIVE POLYMERS DIVISION HOUSTON PLANT	6.68	2.27
DEER PARK TERMINAL	7.06	9.70
DEER PARK PLANT	8.35	359.37
CLEAN HARBORS DEER PARK	8.98	74.78
DEER PARK PLANT	8.92	1599.40
BARGE CLEANING AND REPAIR	5.89	10.29
SHELDON FACILITY	7.29	12.09
TUBOSCOPE HWY 90 COATING FACILITY	6.96	0.02
FAUNA STATION	5.42	0.00
CHANNELVIEW TERMINAL	4.91	1.77
BULK LIQUIDS STORAGE & DISTRIBUTION TERMINAL	6.80	3.53
ALTURA COGEN	2.27	324.56
PASADENA PLANT	8.20	22.85
TEX TRUDE LP	1.12	0.00

Table 4-2. TCEQ 2015 Emission Inventory Data for NO_X Sources within 10 km of the Channelview Monitor (Continued)

Facility Name	Distance from Monitor (km)	NO_X (tpy)
SHELDON NORTH YARD	6.59	0.00
TUBOSCOPE SHELDON SOUTH INSPECTION FACILITY	5.33	8.70
PASADENA PVC PLANT	8.87	30.96
GE AERO ENERGY HOUSTON FACILITY	5.23	45.95
T REX ENGINERRING & CONSTRUCTION LC	5.06	0.00
CHANNELVIEW PLANT	2.79	201.44
CHANNELVIEW ASPHALT FACILITY	4.09	1.37
DEER PARK VCM PLANT	9.44	34.81
CHANNELVIEW FACILITY	4.88	0.00
BATTLEGROUND RD FACILITY	8.16	1.49
HIGHLANDS FACILITY	6.07	4.14
STOLTBARGE SERVICES TANK CLEANING FACILITY & DEPOT	4.43	2.22
LUBE ADDITIVES PLANT	8.79	2.85
BARGE CLEANING FACILITY	4.87	3.71
ABRASIVE BLAST UNIT	6.01	0.00
TUBULAR PROCESSING HOUSTON OPERATIONS	5.13	1.06
PASADENA COGENERATION	9.86	405.42
HOUSTON SHIP CHANNEL FACILITY	7.18	3.32
CHN1 METER 1	3.10	0.00
APPELT TERMINAL	4.67	2.10
DIAMOND FIBERGLASS HOUSTON PLANT	7.92	0.00
ITC PASADENA TERMINAL	8.56	11.19
ETHYLENE PIPELINE EQUIPMENT	9.48	0.00
PETROMAX SHELDON RD	5.70	6.90
PROPYLENE PIPELINE EQUIPMENT	9.40	0.27
POLYSILICON FACILITY	7.98	5.41
PASADENA PLANT	8.15	2.21
EPOLP HOUSTON SHIP CHANNEL MARINE LOADING FACILITY	6.94	9.75
CHANNELVIEW COGENERATION FACILITY	3.81	308.01
POLYPROPYLENE PLANT	9.10	11.03
Total NO_X Emissions Reported (tpy)		**5,544.54**

Source: 2015 Emission Inventory Data, including coordinates used to determine distances, were provided via email by Mr. Adam Bullock, TCEQ, to Mr. Xu Liu, Trinity Consultants, on February 10, 2017.

Table 4-3. TCEQ 2015 Emission Inventory Data for NO_X Sources within 10 km of the Corpus Christi Waterfront Area

Facility Name	Distance from Site (km)	NO_X (tpy)
CORPUS CHRISTI TERMINAL	1.63	14.60
NUECES BAY POWER STATION	3.03	113.99
EAST PLANT REFINERY	2.54	514.13
VALERO CORPUS CHRISTI REFINING EAST	1.11	365.56
ELEMENTIS CHROMIUM CORPUS CHRIST TX FACILITY	1.72	136.23
CORPUS CHRISTI WEST PLANT	3.15	727.50
CORPUS CHRISTI EAST PLANT	3.13	111.06
WEST REFINERY	7.48	1321.81
DEEP SEA TERMINAL	1.39	0.00
WEST PLANT FACILITY	4.44	407.48
GRAVITY MIDSTREAM CORPUS CHRISTI	3.95	0.76
GAS PROCESSING FACILITY	1.21	19.98
CORPUS CHRISTI CRUDE TERMINAL	4.37	12.20
BUCKEYE TEXAS HUB	4.98	52.00
HYDROGEN PLANT INDUST GAS	2.73	56.59
COGENERATION FACILITY	2.19	478.18
CORPUS CHRISTI LP TANK FARM	3.77	3.60E-03
TALBERT FACILITY	6.33	32.87
GT & T FACILITY	6.04	0.00
WILSON 1 FACILITY	5.79	5.48
CORPUS CRUDE OIL TERMINAL	5.21	9.53
CORPUS CHRISTI FACILITY	5.43	10.20
EAST WHITE POINT PRODUCTION FACILITY	8.76	59.01
NUECES BAY STATE TRACT PRODUCTION FACILITY	5.81	11.92
Total NO_X Emissions Reported (tpy)		**4,461.08**

Source: 2015 Emission Inventory Data, including coordinates used to determine distances, were provided via email by Mr. Adam Bullock, TCEQ, to Mr. Xu Liu, Trinity Consultants, on February 10, 2017.

Table 4-4. County Population and NO_X Emissions

Location	Description	County	2016 Population [1]	NO_X EI Annual Emission Rate [2] (tpy)
Channelview Monitor (EPA ID: 48-201-0026)	NO_X Monitor	Harris	4,589,928	15,943
Corpus Christi Waterfront Area	On-shore Location in the vicinity of the SPM buoy system	Nueces	361,350	7,137

[1] 2016 population estimate data from: https://www.census.gov/quickfacts/fact/table/harriscountytexas,nuecescountytexas/PST045216 (accessed in August 2017).
[2] 2015 Emission Inventory Data, including coordinates used to determine distances, were provided via email by Mr. Adam Bullock, TCEQ, to Mr. Xu Liu, Trinity Consultants, on February 10, 2017.

Table 4-5. NO_2 Monitor Summary for Channelview Monitor (EPA ID: 48-201-0026)

	Percent Complete					98th Percentile 1-hr Concentration	Annual Average
	1-hour Average Period [1]						
Year	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual Averaging Period [2]	(µg/m³)	(µg/m³)
2014	100.00%	93.41%	100.00%	96.74%	95.98%	80.49	--
2015	100.00%	100.00%	100.00%	90.22%	96.11%	94.22	--
2016	100.00%	87.91%	100.00%	98.91%	95.33%	85.19	17.58
Three-Year Concentrations [3]:						**87**	**18**

Source: Monitor data are obtained from the TCEQ Air Monitoring website (http://www.tceq.us/cgi-bin/compliance/monops/yearly_summary.pl?cams=15).
[1] Completeness for 1-hour averaging period is shown by 75% of days in a quarter recording at least 75% of hourly samples.
[2] Completeness for annual averaging period is shown with recorded samples for at least 75% of total hours in a year.
[3] The 3-year concentration for the 1-hour averaging period is the mean of the three annual 98th percentile values for the most recent consecutive 3 years of complete data, and for the annual averaging period it is the mean of all reported 1-hour values from the most recent complete year, per 40 CFR Part 50, Appendix S, and TCEQ Modeling Guidance (APDG 6232v2, April 2015), Appendix D.

As mentioned previously, for conservatism, the NO_2 concentrations from the Channelview Monitor in Harris County have been utilized and TGTI believes this adequately represent both off-property sources and background for the NAAQS demonstration.

5. SUMMARY OF NEPA AIR QUALITY ANALYSIS RESULTS

The following section details the results of the air quality modeling. The results indicate the maximum modeled concentrations for CO, SO_2, PM_{10}, and $PM_{2.5}$ do not exceed the corresponding SIL values. In addition, NO_2 combined with the nearest representative onshore NO_2 monitor concentrations do not exceed the NO_2 1-hour as well as annual NAAQS. Table 5-1 shows the results from the modeling analysis. Since the NO_2 1-hour concentration exceeds the SIL, the 98th percentile (i.e., eight highest high) of 1-hour daily maximum concentration, averaged over 3 years is to be added to NO_2 1-hour background concentration, and then compared the total against the NO_2 1-hour NAAQS. Since the OCD model output provides results only up to the fifth highest high (H5H), for conservatism the H5H modeled NO_2 1-hour concentration averaged over 5 years is added to the NO_2 1-hour background concentration, and then compared against the respective NAAQS. Therefore, the proposed Project is not expected to result in direct, indirect, or cumulative impacts that will result in a violation of the NAAQS.

Table 5-1. Modeled Concentrations

Pollutant	Averaging Period	Modeled Concentration (µg/m³)	SIL (µg/m³)	Pass at SIL (Yes/No)	Background Monitor Concentration [19] (µg/m³)	Modeled Concentration + Background Value (µg/m³)	Primary and Secondary NAAQS (µg/m³)	Below NAAQS (Yes/No)
CO	1-hour	30.72	2000	Yes	N/A	N/A	40,000	N/A
	8-hour	10.76	500	Yes	N/A	N/A	10,000	N/A
SO_2	3-hour	4.09	25	Yes	N/A	N/A	1,300	N/A
	24-hour	1.31	5	Yes	N/A	N/A	--	N/A
	Annual	0.05	1	Yes	N/A	N/A	--	N/A
	1-hour	6.22	7.9	Yes	N/A	N/A	196	N/A
NO_2	Annual	1.04	1	No	18	1.04+18	100	Yes
	1-hour[20]	69.57*	7.5	No	87	69.57+87 = 156.57	188	Yes
$PM_{10}/PM_{2.5}$	24-hour	0.80	5/1.2	Yes	N/A	N/A	150/35	N/A
	Annual	0.03	1/0.3	Yes	N/A	N/A	50/15	N/A

*H5H modeled 1-hour concentration of NO_2 = 5 year Average of H5H Maximum Modeled NO_2 Concentration

= Average (53.71, 76.46, 71.87, 65.52, 80.27)

= 69.57 µg/m³

[19] The background monitor concentration has only been included for pollutants that exceed the significant impact level promulgated by EPA.

[20] The percentile approach allows the evaluation of the NAAQS based on the 98th percentile of the 3-year average of the daily maximum values (highest 8th high, H8H). The highest 1st high (H1H) value 114.69 µg/m³ but based on the percentile approach, the air quality impacts have been evaluated based on the H5H due to unavailability of H8H values.

6.1 HEALTH EFFECTS EVALUATION

This section discusses the modeling results for the State Health Effects Evaluation. The non-criteria pollutant emissions (crude/condensate) were evaluated according to the MERA analysis approach, as described below.

The crude/condensate emissions emitted from the proposed SPM operation's emission sources are evaluated using the ESL for crude/condensate. Speciation of crude/condensate is not required as ESLs have been published for crude/condensate. For this Health Effects Evaluation, all ESLs are obtained from the TCEQ's Toxicity Factor Database.[23]

Both crude and condensate have short-term ESL of 3,500 μg/m^3 and a long-term ESL of 350 μg/m^3. Therefore, the worst-case emissions between crude and condensate on an hourly basis, and annual basis have been evaluated. Health Effects Evaluation at the proposed project location is performed according to the March 2018 MERA guidance. Since the only source of emissions at the proposed project will be crude/condensate loading, TGTI skipped the MERA steps and directly performed Step 7(site-wide modeling).[24] A refined air dispersion modeling analysis is performed for the sources emitting the worst-case representative products (i.e., condensate/crude and diesel). The refined OCD model runs are performed such that marine loading at the proposed SPM location is modeled at the worst-case hourly emission rate. The modeled concentration obtained through the refined modeling analysis is compared with the corresponding ESL. If the modeled concentration for this product is less than the corresponding ESL, compliance with the health effects review is demonstrated. If the modeled concentration is greater than the ESL, a Tier II or Tier III analysis is performed to evaluate the health effect.

The modeled concentrations of crude/condensate from the MERA analysis are provided in Table 6-1 below. Since the model predicted maximum hourly and annual impacts for condensate/crude do not exceed the corresponding ESLs, no further analysis is required.

Table 6-1. Summary of Modeling Results for the Health Effect Review

Pollutant/ Product	CAS Number	Averaging Period	ESL (μg/m^3)	ESL Basis	Maximum Modeled Concentration (Modeled concentration) (μg/m^3)	Modeled Concentration < ESL?
Condensate/ Crude	64741-47-5	Hourly	3500	Health	655.53	Yes
		Annual	350	Health	6.10	Yes

[23] URL: http://www17.tceq.texas.gov/tamis/index.cfm?fuseaction=home.welcome

[24] TCEQ Guidance Document: *Modeling and Effects Review Applicability*, APDG 5874v5, Revised 03/18.

7. OZONE IMPACT ANALYSIS

Ozone is formed from precursor VOC and NO_X emissions. Any site with a net emissions increase of 100 tpy or more of VOC or NO_X that is subject to PSD is required to perform an ozone impact analysis.[25,26] As indicated in this modeling report, the total emissions of VOC are anticipated to be greater than 100 tpy.

Representative ozone monitoring data were obtained and are used to demonstrate that the location of the project is currently in compliance with the 8-hour ozone standard. The Corpus Christi West Monitor is proposed as the representative/conservative ozone monitor for the proposed project. The 3-year average of the annual 4th highest daily maximum 8-hour concentrations at this monitor is 64 ppb, which is less than the 8-hour ozone standard of 70 ppb. Because this monitor is representative of the proposed SPM operations, TGTI used this monitor in lieu of obtaining preconstruction monitoring data.
Kleberg County where the onshore TGTI terminal will be located is designated as attainment or unclassifiable for all NAAQS. For offshore locations beyond the seaward state territorial boundary, no status has been designated with respect to the NAAQS. Therefore, the NAAQS attainment status of the nearest adjacent onshore location should be considered. Kleberg County and Nueces County are the nearest onshore locations to the proposed Port are designated as attainment or undesignated for all NAAQS.

Formation of ozone is either limited by NO_x emissions (NO_X-limited) or by VOC emissions (VOC-limited). Based on regional photochemical modeling using Comprehensive Air Quality Model with extensions (CAM_X), the Corpus Christi area is NO_X-limited for ozone formation.[27] The authors publishing these results undertook the study in order to evaluate the impact of anthropogenic emissions sources on ozone concentrations. To this end, the photochemical modeling study simulated a high ozone episode in several urban Texas areas. Through a source apportionment analysis of emissions influencing the 8-hour ozone concentrations, NO_X and VOC limited areas were identified. According to the results, the Corpus Christi area was determined to be NO_X-limited for ozone formation. The results also showed that ozone concentrations in the Corpus Christi area are primarily impacted by long-range transport, with lesser amounts of ozone formed from local emissions.

Since TGTI's VOC emission increase from the project is greater than 100 tpy, Trinity performed a qualitative assessment of the potential ozone impacts from the post-project total VOC emissions, using CAMx modeling results from NuStar Logistics, LP's (NuStar) PSD permit application for the Corpus Christi Terminal approved by the TCEQ on April 10, 2012.[28] The potential ozone impacts from NO_X emissions from the proposed SPM operations are not assessed since NO_X emission increases are less than 100 tpy[29]. In addition, the NO_X emission increases are less than the NO_X SER; therefore, formation of ozone from project NO_X emissions is expected to be insignificant. The VOC ozone impacts analysis is described below.

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[25] 40 CFR §52.21 (i)(5)(i)(f)

[26] 40 CFR §52.21 (i)(5)(i)

[27] "Modeling analysis of the impact of anthropogenic emission sources on ozone concentration over selected urban areas in Texas," Farooqui, Zuber M., Kuruvilla John, Jhumoor Biswas, and Neelesh Sule. Atmospheric Pollution Research, 2013, 33-42. http://www.atmospolres.com/articles/Volume4/issue1/APR-13-004.pdf (last accessed August 2015).

[28] Air Quality Analysis (Ozone), Permit No. 32769, Nustar Logistics, L.P. – Corpus Christi Terminal, December 22. 2011.

[29] The NO_x emissions discussed here do not include secondary NO_x emissions from support vessel and crude tanker operation.

The NuStar Corpus Christi Terminal is located in close proximity to TGTI's inland terminal. The VOC emission sources from both facilities include ship loading fugitives. NuStar performed CAMx modeling to assess the impacts of VOC emissions increases on the 8-hour ozone concentrations in the Corpus Christi area. Based on the similarities in location and emission sources, it is reasonable to use the CAMx ozone modeling results conducted for NuStar to evaluate ozone impacts from VOC emissions from the SPM operations.

The maximum hourly VOC emission rate increase from the sources evaluated at the NuStar Corpus Christi Terminal resulted in an annualized emission increase of 1,104 tpy of VOC. Based on the 2011 photochemical CAMx modeling of the NuStar project, the increase in VOC emissions resulted in a model-predicted impact of 0.10 to 0.18 ppb in the 8-hour ozone concentration. Thus, NuStar concluded that the proposed increase in VOC emissions from the SPM operations would have minimal impacts on the ozone concentrations in the Corpus Christi urban air shed and surrounding areas.

For the SPM operations, Trinity compared the annualized VOC emission rate to the NuStar annualized VOC emission rate in order to calculate a reasonable estimate of impact of the SPM operations on the 8-hour ozone. For the SPM operations, Trinity conservatively calculated an annualized VOC emission rate using the preliminary maximum allowable hourly VOC emission rate from marine loading, times 8,760 hours per year. The annualized hourly VOC emissions from these sources is 10,855 tpy. The quantity of these VOC emissions are approximately 10 times greater than the annualized hourly VOC emissions evaluated for the NuStar project that were determined to have a minimal impact on the 8-hour ozone concentration in the Corpus Christi urban air shed. Thus, it is reasoned that the VOC emissions from the proposed SPM operations would also have a minimal impact of less than 2 ppb in 8-hour ozone concentration. Applying the ratio of SPM operations' annualized hourly emissions (to be conservative) and the NuStar emissions (10,855 tpy/1,104 tpy) to the maximum ozone impact of 0.18 ppb predicted for the NuStar project would result in a maximum impact for the SPM operations of 1.77 ppb ozone. The three-year average (2014-2016) of the 4th highest 8-hour ozone concentrations from the representative background monitor (Corpus Christi West Monitor) is 64 ppb. The estimated increase of less than 2 ppb from the SPM operations using this conservative qualitative assessment based on representative CAMx modeling results would not result in exceeding the 8-hour ozone NAAQS of 70 ppb.

CASE-BY-CASE MACT PERMIT APPLICATION

Texas Gulf Terminals Inc.
Texas Gulf Terminals Project

Appendix D

Prepared By:

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(361)-883-1668

July 2018

Trinity Consultants

Environmental solutions delivered uncommonly well

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1.1. PROJECT BACKGROUND

Texas Gulf Terminals Inc. (TGTI) is proposing to construct, own, and operate a deepwater port (DWP) as part of the Texas Gulf Terminal Project, in Federal waters of the U.S. Gulf of Mexico located approximately 14 miles off the coast of North Padre Island in Kleberg County, Texas.

The purpose of the proposed project is to provide a safe, efficient and cost effective logistical solution for the export of crude oil from the United States of America (U.S.) to support the continued economic growth of the U.S.

The DWP terminal will include a Single Point Mooring (SPM) buoy system to moor a Very Large Crude Carrier (VLCC). The size of these VLCCs and inland port draft limitations prevent them from using the traditional docks at onshore terminals. Therefore, VLCCs have to be engaged offshore. The proposed SPM buoy system will be located in water with over 90 feet of depth, allowing a VLCC to be fully and directly loaded without the use of lightering (i.e., using smaller ships to transport crude oil from on-shore terminals out to VLCCs located in deeper waters).

The project will serve as a crude oil export facility with a capacity of 60,000 barrels per hour (bph) and 192 million barrels per year. The project will be able to load approximately 96 VLCCs per year. The proposed project is comprised of two major offshore components: the SPM Buoy system and the offshore pipelines. A detailed description of the SPM Buoy system components and the offshore pipeline system is provided in Section 3.

1.2. PURPOSE OF APPLICATION

The proposed SPM buoy system will represent a major source of HAP emissions that is not specifically regulated or exempted from regulation under a standard issued pursuant to section 112(d), section 112(h) or section 112(j) and incorporated in another subpart of part 63. Accordingly, the requirements of 40 CFR 63.40 through 63.44 apply. The regulations contained in 40 CFR 63.40 through 63.44 carry out section 112(g)(2)(B) of the Clean Air Act (CAA) as it relates to a Case-by-Case MACT determination. As such, TGTI has prepared a Case-by-Case MACT determination application in accordance with 40 CFR 63.40 through 63.44 and Section 112(g) of the CAA.

To reach this conclusion, TGTI conducted an extensive review of each of the National Emissions Standards for Hazardous Air Pollutants (NESHAP) regulation to identify any potentially applicable NESHAP regulations that might apply to the proposed SPM buoy system. Only one type of NESHAP regulations was identified that could be potentially applicable to the proposed SPM buoy system: NESHAP Subpart Y – National Emissions Standards for Marine Tank Vessel Loading Operations. The following section details why TGTI concluded NESHAP Subpart Y does not apply to the proposed SPM buoy system.

1.2.1. NESHAP Subpart Y – Marine Tank Vessel Loading Operations Inapplicability

NESHAP Subpart Y applies to affected sources of Marine Tank Vessel Loading Operations. The following definitions from NESHAP Subpart Y (40 CFR 63.561) are important provisions used to determine what qualifies as an affected source regulated under NESHAP Subpart Y.

Affected source *means a source with emissions of 10 or 25 tons, a new major source with emissions less than 10 and 25 tons, a new major source offshore loading terminal, a source with throughput of 10 M barrels or 200 M barrels, or the VMT source, that is subject to the emission standards in §63.562.*

Source(s) *means any location where at least* ***one dock or loading berth*** *is bulk loading onto marine tank vessels, except offshore drilling platforms and lightering operations.*

Offshore Loading Terminal *means a location that has at least* ***one loading berth*** *that is 0.81 km (0.5 miles) or more from the shore that is used for mooring a marine tank vessel and loading liquids from shore."*

Loading berth *means the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill marine tank vessels. The loading berth includes those items necessary for an offshore loading terminal.*

The proposed SPM buoy system does not fit the definition of a "loading berth" per the definition set forth in 40 CFR 63.561 since the proposed SPM buoy system will not have loading arms, pumps, meters, shutoff valves, nor relief valves. Additionally, the proposed SPM buoy system does not have a "dock" or any fixed structure resembling a dock structure. Per the Cambridge Dictionary, a dock is defined as "a structure built out over the water in a port along which ships can land to load and unload, or the enclosed area of water between two such structures."

Therefore the proposed SPM buoy system does not fit the definition of an "affected source" because it does not meet the definition of a "source" as stated in 40 CFR 63.561.

The definitions of "offshore loading terminal" and "loading berth" are essentially circular. Therefore, TGTI also reviewed the NESHAP Subpart Y preamble and technological support documents to determine if there were any sources similar to the proposed SPM buoy system that were considered in the rulemaking. Based on this review, TGTI concluded that there were no similar sources to the proposed SPM buoy system (i.e., SPM buoy systems for directly and completely loading a VLCC for crude oil export) considered in the development of the NESHAP Subpart Y regulations. The proposed SPM buoy system will be a first of its kind for the United States. Export of crude oil was banned in the United States from 1975, following the 1973 OPEC oil embargo, until 2015 to all countries except Canada. Therefore, because of this legal restriction, there could not have been similar sources in operation when NESHAP Subpart Y was developed in 1995 nor when it was reconsidered in 2011.

The proposed SPM buoy system also presents unique technical, environmental, and operational concerns compared to the sources that were considered in the establishment of MACT Subpart Y standards. EPA acknowledged in responses to comments on the 1995 NESHAP Subpart Y rule that the subcategory established for "offshore terminals" could be expanded to include additional subcategories based on throughputs, products handled, etc. It did not, however, consider doing so in 1995 because the public comments did not justify additional subcategories. This reinforces TGTI's conclusion that the proposed SPM buoy system is not an affected source under NESHAP Subpart Y.

1.2.2. Case-by-Case MACT Submittal

Since there are no applicable standards in either 40 CFR Part 61 or Part 63 that apply to the proposed SPM buoy system, this Case-by-Case MACT application has been prepared to present a Case-by-Case MACT determination for the proposed SPM buoy system in accordance with Section 112(g) of the Clean Air Act (CAA) and the implementing regulations in 40 CFR Part 63, Subpart B (40 CFR 63.40 – 63.56). Since Texas is the most adjacent

seaward state, TCEQ regulations are also potentially applicable. Therefore, this application is also being submitted in accordance with 30 TAC Chapter 116, Subchapter E which implements Section 112(g) and 40 CFR Part 63, Subchapter B.

2. APPLICANT INFORMATION: TCEQ FORMS

CORE DATA FORM

PI-1 FORM

TABLE 1(a)

TCEQ Core Data Form

TCEQ Use Only

For detailed instructions regarding completion of this form, please read the Core Data Form Instructions or call 512-239-5175.

SECTION I: General Information

1. Reason for Submission (If other is checked please describe in space provided.)

☒ New Permit, Registration or Authorization (Core Data Form should be submitted with the program application.)

☐ Renewal (Core Data Form should be submitted with the renewal form) ☐ Other

2. Customer Reference Number (if issued)		3. Regulated Entity Reference Number (if issued)
CN 605490085	Follow this link to search for CN or RN numbers in Central Registry**	RN

SECTION II: Customer Information

4. General Customer Information 5. Effective Date for Customer Information Updates (mm/dd/yyyy)

☐ New Customer ☐ Update to Customer Information ☐ Change in Regulated Entity Ownership
☐ Change in Legal Name (Verifiable with the Texas Secretary of State or Texas Comptroller of Public Accounts)

The Customer Name submitted here may be updated automatically based on what is current and active with the Texas Secretary of State (SOS) or Texas Comptroller of Public Accounts (CPA).

6. Customer Legal Name (If an individual, print last name first: e.g.: Doe, John) If new Customer, enter previous Customer below:

Texas Gulf Terminals Inc.

7. TX SOS/CPA Filing Number	8. TX State Tax ID (11 digits)	9. Federal Tax ID (9 digits)	10. DUNS Number (if applicable)
0802978324	32066715692		

11. Type of Customer: ☒ Corporation ☐ Individual Partnership: ☐ General ☐ Limited
Government: ☐ City ☐ County ☐ Federal ☐ State ☐ Other ☐ Sole Proprietorship ☐ Other:

12. Number of Employees
☒ 0-20 ☐ 21-100 ☐ 101-250 ☐ 251-500 ☐ 501 and higher

13. Independently Owned and Operated?
☒ Yes ☐ No

14. Customer Role (Proposed or Actual) - as it relates to the Regulated Entity listed on this form. Please check one of the following:

☐ Owner ☐ Operator ☒ Owner & Operator
☐ Occupational Licensee ☐ Responsible Party ☐ Voluntary Cleanup Applicant ☐ Other:

15. Mailing Address:

1401 McKinney							
Suite 1500							
City	Houston	State	TX	ZIP	77010	ZIP + 4	

16. Country Mailing Information (if outside USA)	17. E-Mail Address (if applicable)

18. Telephone Number	19. Extension or Code	20. Fax Number (if applicable)
(832) 203 - 6400		( ) -

SECTION III: Regulated Entity Information

21. General Regulated Entity Information (If `New Regulated Entity" is selected below this form should be accompanied by a permit application)

☒ New Regulated Entity ☐ Update to Regulated Entity Name ☐ Update to Regulated Entity Information

The Regulated Entity Name submitted may be updated in order to meet TCEQ Agency Data Standards (removal of organizational endings such as Inc, LP, or LLC).

22. Regulated Entity Name (Enter name of the site where the regulated action is taking place.)

Texas Gulf Terminals Project

23. Street Address of the Regulated Entity: (No PO Boxes)								
	City		State		ZIP		ZIP + 4	
24. County								

Enter Physical Location Description if no street address is provided.

25. Description to Physical Location:	Site is approximately 14 miles offshore the coast of Texas, Southeast of Corpus Christi.		
26. Nearest City		State	Nearest ZIP Code
N/A		TX	N/A

27. Latitude (N) In Decimal:	27.4785		28. Longitude (W) In Decimal:	97.013453	
Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
27	28	42.6	97	00	48.43

29. Primary SIC Code (4 digits)	30. Secondary SIC Code (4 digits)	31. Primary NAICS Code (5 or 6 digits)	32. Secondary NAICS Code (5 or 6 digits)
4612		486910	

33. What is the Primary Business of this entity? (Do not repeat the SIC or NAICS description.)

Offshore Marine Terminal

34. Mailing Address:	1401 McKinney							
	Suite 1500							
	City	Houston	State	TX	ZIP	77010	ZIP + 4	

35. E-Mail Address:		
36. Telephone Number	37. Extension or Code	38. Fax Number (if applicable)
(832) 203 - 6400		( ) -

39. TCEQ Programs and ID Numbers Check all Programs and write in the permits/registration numbers that will be affected by the updates submitted on this form. See the Core Data Form instructions for additional guidance.

☐ Dam Safety	☐ Districts	☐ Edwards Aquifer	☐ Emissions Inventory Air	☐ Industrial Hazardous Waste
☐ Municipal Solid Waste	☐ New Source Review Air	☐ OSSF	☐ Petroleum Storage Tank	☐ PWS
☐ Sludge	☐ Storm Water	☐ Title V Air	☐ Tires	☐ Used Oil
☐ Voluntary Cleanup	☐ Waste Water	☐ Wastewater Agriculture	☐ Water Rights	☒ Other: Section 112(g) Case-by-Case MACT

SECTION IV: Preparer Information

40. Name:	Denise Rogers		41. Title: Compliance Manager
42. Telephone Number	43. Ext./Code	44. Fax Number	45. E-Mail Address
(832) 203 - 6493		( ) -	denise.rogers@texasgulfterminals.com

SECTION V: Authorized Signature

46. By my signature below, I certify, to the best of my knowledge, that the information provided in this form is true and complete, and that I have signature authority to submit this form on behalf of the entity specified in Section II, Field 6 and/or as required for the updates to the ID numbers identified in field 39.

Company:	Texas Gulf Terminals Inc	Job Title:	Compliance Manager
Name(*In Print*):	Denise Rogers	Phone:	(832) 203-6493
Signature:	Denise Rogers	Date:	6/27/2018

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

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

I. Applicant Information		
A. Company or Other Legal Name: Texas Gulf Terminals Inc.		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Information: (☐ Mr. ☐ Mrs. ☒ Ms. ☐ Other:) _____		
Name: Denise Rogers		
Title: Compliance Manager		
Mailing Address: 1401 McKinney, Suite 1500		
City: Houston	State: TX	ZIP Code: 77010
Telephone No.: 832-203-6493	Fax No.: 832-203-6401	
E-mail Address: denise.rogers@texasgulfterminals.com		
All permit correspondence will be sent via electronic copies unless hard copies are specifically requested through regular mail. The company official must initial here if hard copy correspondence is requested. _____		
C. Technical Contact Name Information: (☐ Mr. ☐ Mrs. ☒ Ms. ☐ Other:) _____		
Name: Denise Rogers		
Title: Compliance Manager		
Company Name: Texas Gulf Terminals Inc.		
Mailing Address: 1401 McKinney, Suite 1500		
City: Houston	State: TX	ZIP Code: 77010
Telephone No.: 832-203-6493	Fax No.: 832-203-6401	
E-mail Address: denise.rogers@texasgulfterminals.com		
D. Site Name: Texas Gulf Terminals Project		
E. Area Name/Type of Facility:		☒ Permanent ☐ Portable
For portable units, please provide the serial number of the equipment being authorized below.		
Serial No:	Serial No:	
F. Principal Company Product or Business: Offshore Marine Terminal		
Principal Standard Industrial Classification Code (SIC): 4612		
Principal North American Industry Classification System (NAICS): 486910		
G. Projected Start of Construction Date: TBD		
Projected Start of Operation Date: TBD		

I. Applicant Information (continued)		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: Site is approximately 14 miles offshore the coast of Texas, Southeast of Corpus Christi.		
City/Town: N/A	County: N/A	ZIP Code: N/A
Latitude (nearest second): 27˚ 28' 42.6"	Longitude (nearest second): 97˚ 00' 48.43"	
I. Account Identification Number (leave blank if new site or facility):		
J. Core Data Form		
Is the Core Data Form (Form 10400) attached? If No, provide customer reference number and regulated entity number (complete K and L).		☒ YES ☐ NO
K. Customer Reference Number (CN):		
L. Regulated Entity Number (RN):		
II. General Information		
A. Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.		☐ YES ☒ NO
B. Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.		☐ YES ☒ NO
C. Number of New Jobs: N/A		
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:		
State Senator: N/A	District No.: N/A	
State Representative: N/A	District No.: N/A	
III. Type of Permit Action Requested		
A. Mark the appropriate box indicating what type of action is requested.		
☒ Initial	☐ Amendment	☐ Revision (30 TAC § 116.116(e)
☐ Change of Location		☐ Relocation
B. Permit Number (if existing):		
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)*		
☐ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit		
☐ Prevention of Significant Deterioration (PSD)	☒ Hazardous Air Pollutant Major Source	
☐ PSD for greenhouse gases (GHGs)	☐ Other:_____	

III. Type of Permit Action Requested *(continued)*		
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC § 116.315(c).		☐ YES ☒ NO
E. Is this application for a change of location of previously permitted facilities?		☐ YES ☒ NO
If Yes, complete all parts of III.E.		
Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO," attach detailed information.		☐ YES ☐ NO
Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?		☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.		
List: N/A		
G. Are you permitting planned maintenance, startup, and shutdown emissions?		☐ YES ☒ NO
If Yes, attach information on any changes to emissions under this application as specified in VII and VIII.		
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability)		
Is this facility located at a site required to obtain a federal operating permit?		☒ YES ☐ NO ☐ To be determined
If Yes, list all associated permit number(s), attach pages as needed).		
Associated Permit No (s.):		
Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.		
☐ FOP Significant Revision	☐ FOP Minor	☐ Application for an FOP Revision
☐ Operational Flexibility/Off-Permit Notification		☐ Streamlined Revision for GOP
☒ To be Determined		☐ None

III. Type of Permit Action Requested *(continued)*	
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)***	
☐ GOP Issued ☐ GOP application/revision application submitted or under APD review	
☐ SOP Issued ☐ SOP application/revision application submitted or under APD review	
IV. Public Notice Applicability	
A. Is this a new permit application or a change of location application?	☒ YES ☐ NO
B. Is this application for a concrete batch plant? If Yes, complete all parts of V.D.	☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA § 112(g) permit, or exceedance of a PAL permit?	☐ YES ☒ NO
D. If this is an application for emissions of GHGs, select one of the following:	
☐ separate public notice (requires a separate application) ☒ consolidated public notice	
E. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☐ YES ☒ NO
If Yes, list the affected state(s) and/or Class I Area(s).	
List:	
F. Is this a state permit amendment application? If Yes, complete all parts of IV.F.	
Is there any change in character of emissions in this application?	☐ YES ☐ NO
Is there a new air contaminant in this application?	☐ YES ☐ NO
Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
List the total annual emission increases associated with the application ***(List all that apply and attach additional sheets as needed):***	
Volatile Organic Compounds (VOC):	
Sulfur Dioxide (SO_2):	
Carbon Monoxide (CO):	
Nitrogen Oxides (NO_x):	
Particulate Matter (PM):	
PM 10 microns or less (PM_{10}):	
PM 2.5 microns or less ($PM_{2.5}$):	
Lead (Pb):	
Hazardous Air Pollutants (HAPs):	
Other speciated air contaminants not listed above:	

V. Public Notice Information *(complete if applicable)*		
A. Responsible Person: (☐ Mr. ☐ Mrs. ☐ Ms. ☐ Other:) _____		
Name:		
Title:		
Company Name:		
Mailing Address:		
City:	State:	ZIP Code:
Telephone No.:	Fax No.:	
E-mail Address:		
B. Technical Contact: (☐ Mr. ☐ Mrs. ☐ Ms. ☐ Other:) ___		
Name:		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
Telephone No.:	Fax No.:	
E-mail Address:		
C. Name of the Public Place:		
Physical Address *(No P.O. Boxes)*:		
City:	County:	ZIP Code:
The public place has granted authorization to place the application for public viewing and copying.		☐ YES ☐ NO
The public place has internet access available for the public.		☐ YES ☐ NO
D. Concrete Batch Plants, PSD, and Nonattainment Permits		
County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable:		
Mailing Address:		
City:	State:	ZIP Code:

V. Public Notice Information *(complete if applicable)*		
D. Concrete Batch Plants, PSD, and Nonattainment Permits *(continued)*		
Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
Provide the name, mailing address of the chief executive for the location where the facility is or will be located.		
Chief Executive:		
Mailing Address:		
City:	State:	ZIP Code:
Provide the name, mailing address of the Indian Governing Body for the location where the facility is or will be located.		
Indian Governing Body:		
Mailing Address:		
City:	State:	ZIP Code:
Identify the Federal Land Manager(s) for the location where the facility is or will be located.		
Federal Land Manager(s):		
E. Bilingual Notice		
Is a bilingual program required by the Texas Education Code in the School District?		☐ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?		☐ YES ☐ NO
If Yes, list which languages are required by the bilingual program?		
VI. Small Business Classification *(Required)*		
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?		☐ YES ☒ NO
B. Is the site a major stationary source for federal air quality permitting?		☒ YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?		☒ YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?		☒ YES ☐ NO

VII. Technical Information	
A. The following information must be submitted with your Form PI-1 ***(this is just a checklist to make sure you have included everything)***	
☒ Current Area Map ☒ Plot Plan ☒ Existing Authorizations ☒ Process Flow Diagram ☒ Process Description ☒ Maximum Emissions Data and Calculations ☒ Air Permit Application Tables ☒ Table 1(a) (Form 10153) entitled, Emission Point Summary ☐ Table 2 (Form 10155) entitled, Material Balance ☒ Other equipment, process or control device tables	
B. Are any schools located within 3,000 feet of this facility?	☐ YES ☒ NO
C. Maximum Operating Schedule:	
Hour(s): 24	Day(s): 365
Week(s): 52	Year(s):
Seasonal Operation? If Yes, please describe in the space provide below.	☐ YES ☒ NO
Hour(s):	Day(s):
Week(s):	Year(s):
D. Have the planned MSS emissions been previously submitted as part of an emissions inventory?	☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.	
MSS Facility(s) or Activity	**Year(s)**
E. Does this application involve any air contaminants for which a disaster review is required?	☐ YES ☒ NO
If Yes, list which air contaminants require a disaster review.	

VII.	**Technical Information *(continued)***	
F.	Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)?	☐ YES ☒ NO
G.	Are emissions of GHGs associated with this project subject to PSD?	☐ YES ☒ NO
If "yes," provide a list of all associated applications for this project:		
See attachments		
VIII.	**State Regulatory Requirements** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non-applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*	
A.	Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?	☒ YES ☐ NO
B.	Will emissions of significant air contaminants from the facility be measured?	☐ YES ☒ NO
C.	Is the Best Available Control Technology (BACT) demonstration attached?	☒ YES ☐ NO
D.	Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?	☒ YES ☐ NO
IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non-applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
A.	Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?	☐ YES ☒ NO
B.	Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?	☐ YES ☒ NO
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☐ YES ☒ NO
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA § 112(g)] requirements apply to this application?	☒ YES ☐ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	
Is the estimated capital cost of the project greater than $2 million dollars?		☒ YES ☐ NO
If Yes, submit the application under the seal of a Texas licensed P.E.		

XI. Permit Fee Information	
Check, Money Order, Transaction Number, ePay Voucher Number: N/A	
Fee Amount: $ N/A	
Paid online? N/A	☐ YES ☐ NO
Company name on check:	
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☐ YES ☐ NO ☒ N/A

XII. Delinquent Fees and Penalties

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

XIII. Signature

The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7; the Texas Health and Safety Code, Chapter 382, the Texas Clean Air Act (TCAA) the air quality rules of the Texas Commission on Environmental Quality; or any local governmental ordinance or resolution enacted pursuant to the TCAA. I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.

Name: Denise Rogers

Signature: Denise Rogers
Original Signature Required

Date: 6/27/2018

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	July 2018	**Permit No.:**	TBD	**Regulated Entity No.:**	
Area Name:	Texas Gulf Terminals Project			**Customer Reference No.:**	CN605490085

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

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) POUND**	**(B) TPY**
LOADFUG	LOADFUG	Marine Loading	HAPs	125	200

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	July 2018	**Permit No.:**	TBD	**Regulated Entity No.:**	
Area Name:	Texas Gulf Terminals Project			**Customer Reference No.:**	CN605490085

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

AIR CONTAMINANT DATA			**EMISSION POINT DISCHARGE PARAMETERS**										
1. Emission Point			**4. UTM Coordinates of Emission Point**			**Source**							
						5. Building	**6. Height Above**	**7. Stack Exit Data**			**8. Fugitives**		
EPN (A)	**FIN (B)**	**Name (C)**	**Zone**	**East (Meters)**	**North (Meters)**	**Height (Ft.)**	**Ground (Ft.)**	**Diameter (Ft.) (A)**	**Velocity (FPS) (B)**	**Temperature (°F) (C)**	**Length (Ft.) (A)**	**Width (Ft.) (B)**	**Axis Degrees (C)**
LOADFUG	LOADFUG	Marine Loading	14	696278	3041006	120.0	0.0	4.7	50.0	455	360646	283707	0

EPN = Emission Point Number
FIN = Facility Identification Number

3. AFFECTED SOURCE DESCRIPTION AND PROJECT TIMELINE

The following section provides information required for a case-by-case MACT determination as detailed in 40 CFR Part 63. In each case, the requirement is quoted from 40 CFR Part 63 and followed by the relevant information.

3.1.1. Section 63.43(e)(2)(i)

In each instance where a constructed or reconstructed major source would require additional control technology or a change in control technology, the application for a MACT determination shall contain the following information:

The name and address (physical location) of the major source to be constructed or reconstructed;

The unit to be constructed is an SPM buoy system for export of crude oil loaded onto VLCCs. The proposed SPM buoy system will be located within territorial seas of the OCS Mustang Island Area TX3 (Gulf of Mexico), within the Bureau of Ocean Energy Management (BOEM) block number 823. The proposed SPM buoy system is positioned at Latitude N27° 28' 42.60" and Longitude W97° 00' 48.43", approximately 12.7 nautical miles (14.62 statute miles) off the coast of North Padre Island in Kleberg County, Texas. An aerial shot of the location of the proposed SPM buoy system is provided at the end of this section.

3.1.2. Section 63.43(e)(2)(ii)

A brief description of the major source to be constructed or reconstructed and identification of any listed source category or categories in which it is included;

The proposed SPM buoy system will load crude oil/condensate onto VLCCs connected to the SPM buoy system's loading hose. The crude oil/condensate will be supplied from the Onshore Storage Terminal Facility (OSTF) through subsea pipelines to the SPM buoy and onto the vessel being loaded. The overall handling capacity of the proposed SPM buoy system will be 60,000 barrels per hour (bph) and up to 192 million barrels per year (bpy). A process flow diagram is provided at the end of this section.

3.1.3. Section 63.43(e)(2)(iii)

The expected commencement date for the construction or reconstruction of the major source;

Construction of the proposed SPM buoy system is expected to begin in the 1st quarter of 2020, pending the issuance of all necessary permits and licenses.

3.1.4. Section 63.43(e)(2)(iv)

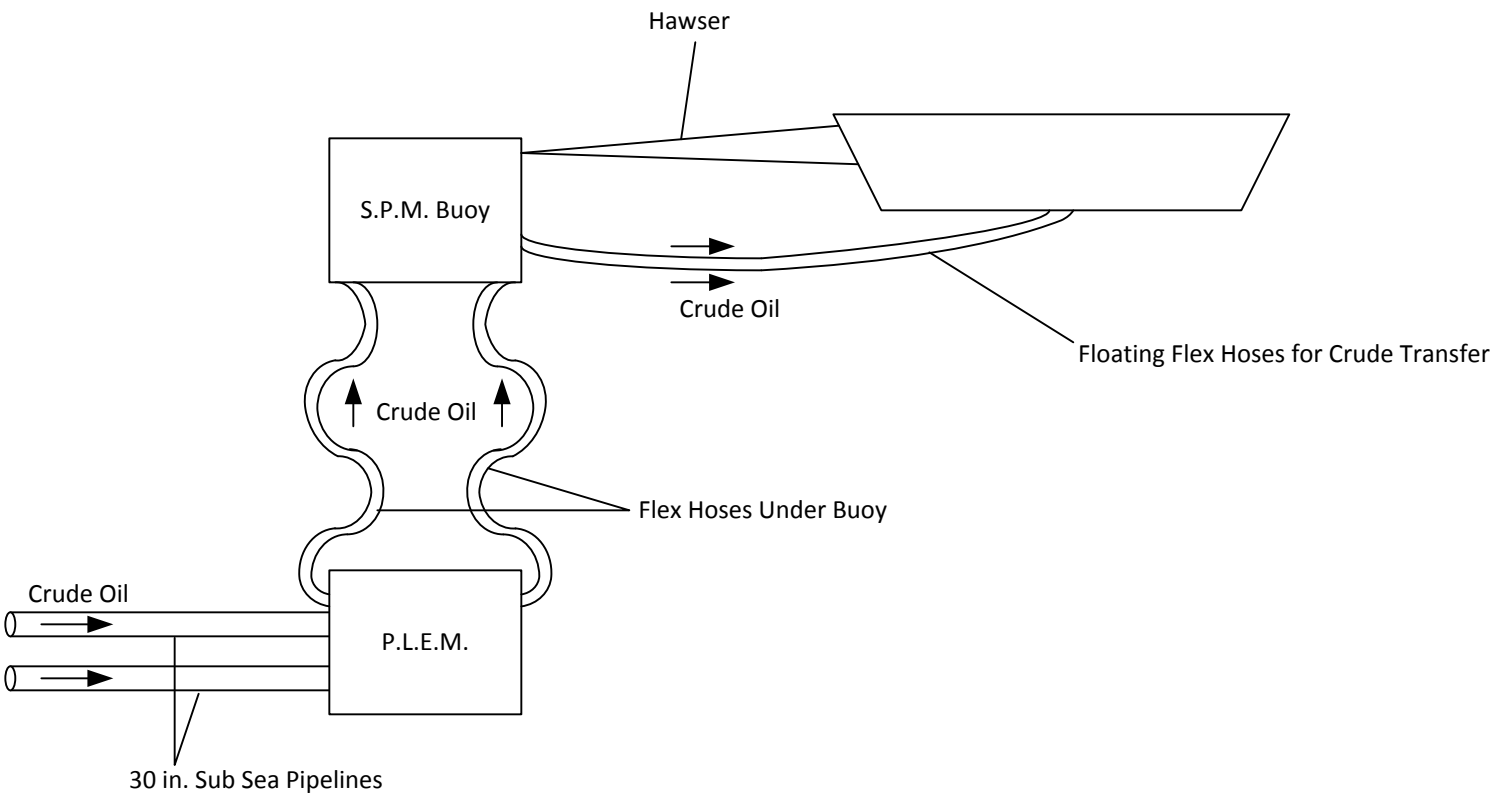
The expected completion date for construction or reconstruction of the major source;

Construction of the SPM buoy system is expected to take approximately 22 weeks. Construction is expected to be completed on the proposed SPM buoy system in the 3rd quarter of 2020.

3.1.5. Section 63.43(e)(2)(v)

The anticipated date of start-up for the constructed or reconstructed major source;

The initial startup of the proposed SPM buoy system is expected to occur shortly after construction is complete in the 3rd quarter of 2020.

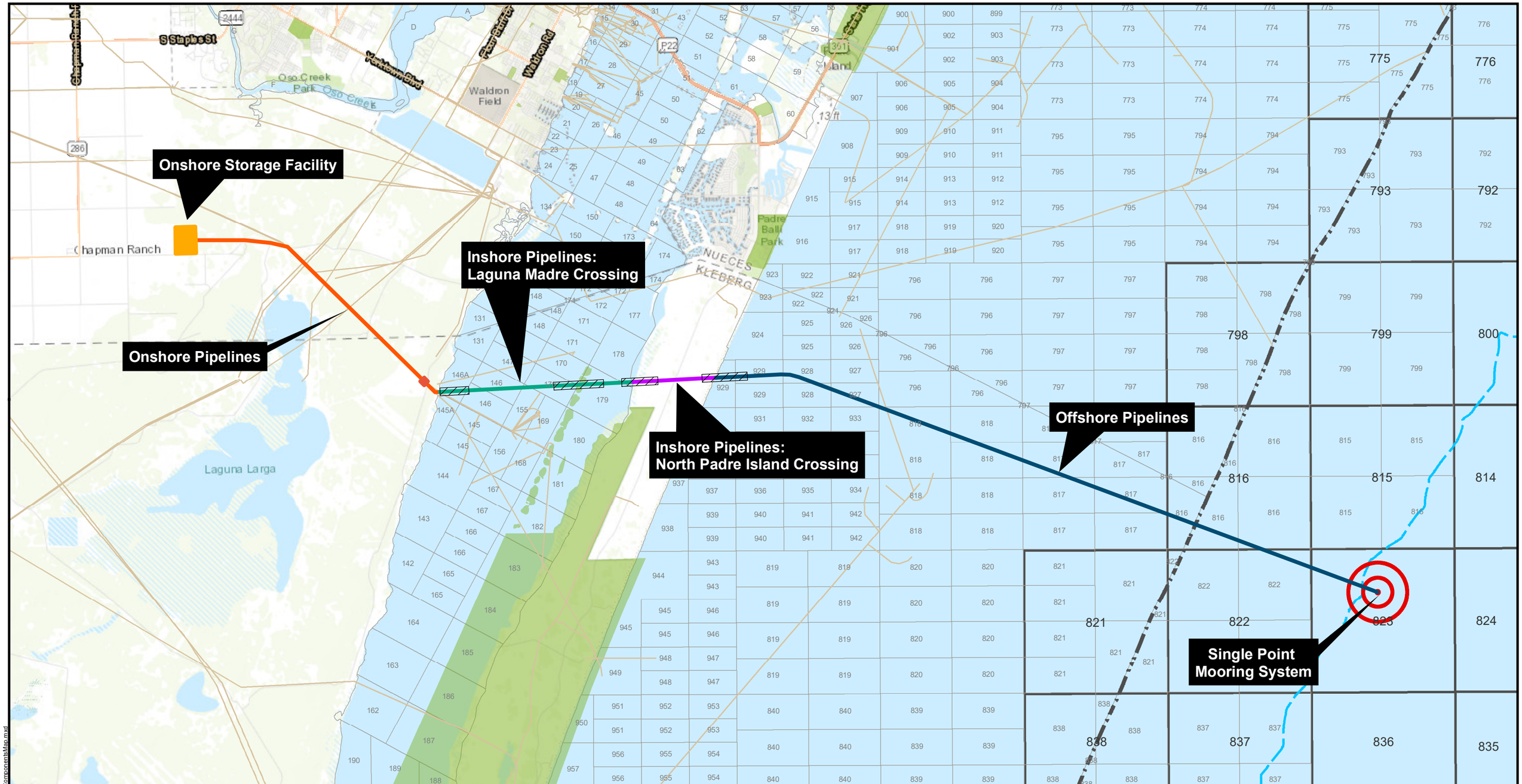


Texas Gulf Terminals Inc.

Process Flow Diagram

Trinity Consultants

Project 184403.0005
April 2018



Legend

- Onshore Storage Facility Property
- Pump Station
- HDD Pipeline Section
- Onshore Segment
- Inshore Laguna Madre Segment
- Inshore North Padre Island Segment
- Offshore Segment
- SPM System and Safety Zone
- Existing Pipelines (RRC)
- Parks, NWRs, WMAs
- 90ft Depth Contour
- Federal/State Line
- GLO Lease Tracts
- Federal Lease Blocks

N

Coordinate System: NAD 1983 StatePlane Texas South Central FIPS 4204 Feet
Projection: Lambert Conformal Conic
Datum: North American 1983
Units: Foot US

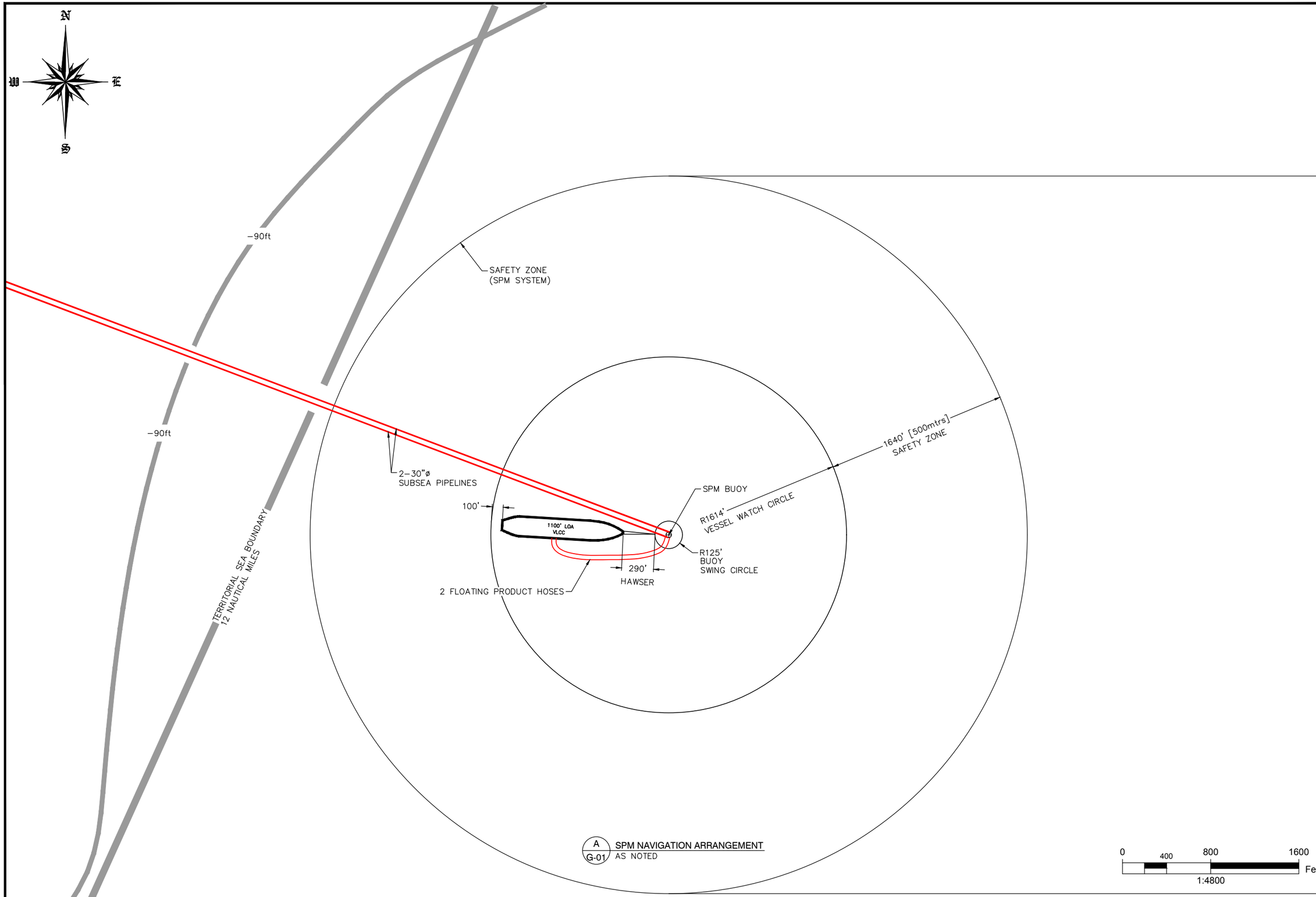
0 5,000 10,000 20,000 Feet

Project Component Overview Map
Texas Gulf Terminals Inc
Texas Gulf Terminals Project

Date: May 21, 2018
Prepared By: CG
Project: TGTI
1 inch = 10,000 feet

LLOYD ENGINEERING, INC.

Document Path: G:\Traffigura SPM Project\Overview Map\ProjectComponentsMap.mxd



A
G-01
SPM NAVIGATION ARRANGEMENT
AS NOTED

NO.	DESCRIPTION	DATE	APPR
A	ISSUED FOR REVIEW	MM/DD/YY	-

ISSUED FOR REVIEW

SEAL

TEXAS GULF TERMINALS INC.

CLIENT

TEXAS GULF TERMINALS PROJECT

SPM ARRANGEMENT DETAIL

LLOYD ENGINEERING, INC
HOUSTON TEXAS, USA
LICENSE NO. F-002846

DESIGN BY:	SL
DRAWN BY:	–
DATE:	MARCH 2018
SCALE:	AS NOTED @ 22"X34"
SHEET:	2 OF 2

DRAWING NO:
REV. A
2

4.1. CRITERIA POLLUTANTS EMISSIONS SUMMARY

4.1.1. Section 63.43(e)(2)(vi)

The HAP emitted by the constructed or reconstructed major source, and the estimated emission rate for each such HAP, to the extent this information is needed by the permitting authority to determine MACT;

HAPs emitted from the proposed SPM buoy system will be those that volatilize from crude oil/condensate as it is loaded onto the VLCC. Detailed emission calculations are provided in Attachment 3.

4.1.2. Section 63.43(e)(2)(vii)

Any federally enforceable emission limitations applicable to the constructed or reconstructed major source;

The PSD/Title V permits issued based on the PSD and Title V permit applications will establish federally enforceable limitations for the proposed SPM system.

4.1.3. Section 63.43(e)(2)(viii)

The maximum and expected utilization of capacity of the constructed or reconstructed major source, and the associated uncontrolled emission rate for that source, to the extent this information is needed by the permitting authority to determine MACT;

As discussed in Section 5 of the NSR application for the proposed SPM buoy system, criteria pollutant emissions from the proposed SPM buoy system will result from loading losses associated with the displacement of air inside the vessel as the vessel is loaded. TGTI estimated the emissions of VOC associated with loading losses of the vessels using TCEQ's Air Permit Technical Guidance for Chemical Sources: Loading Operations (October 2000) and the following equation from US EPA's AP-42, Section 5.2:

$$L = 12.46 \times S \times P \times M/T$$

Where:

L = Loading Loss (lb/10^3 gal of liquid loaded)

S = Saturation factor

P = True vapor pressure of liquid loaded (psia)

M = Molecular weight of vapors (lb/lbmole)

T = Temperature of bulk liquid loaded (R)

A saturation factor of 0.2 is used for submerged loading of ships. A maximum true vapor pressure of 11 psia is used for crude oil/condensate loading.

The maximum loading capacity of the SPM buoy system is 60,000 bph and 192 million bpy. The proposed SPM buoy system is expected to have an expected utilization near 100%. HAP emissions from the proposed SPM buoy system will consist of those HAPs which make up crude oil/condensate. HAP emissions are calculated by assuming the speciation in the vapors lost are the same makeup as the speciation of the crude oil/condensate in the liquid.

4.1.4. Section 63.43(e)(2)(ix)

The controlled emissions for the constructed or reconstructed major source in tons/yr at expected and maximum utilization of capacity, to the extent this information is needed by the permitting authority to determine MACT;

Maximum controlled potential emissions for the proposed SPM system are provided in the table below.

Table 4-1 - Potential HAP Emissions from Proposed SPM Buoy System

Source	HAPs (tpy)
Vessel Loading	200
Fugitives	0.004
Total	**200**

4.2. ALTERNATIVES ANALYSIS

As mentioned in the project background, the purpose of the proposed SPM buoy system will be to fully and directly load VLCCs with crude oil/condensate for export. The proposed SPM buoy system is unique and different from current crude oil/condensate export operations that are currently conducted in the United States. Because of their size (2 MMbbls fully loaded), VLCCs are used for long haul trips to transport cargos long distances across the globe economically. However, their immense size and draft limitations prevents VLCCs from navigating to onshore terminals to be loaded fully. Therefore, VLCCs are currently loaded by lightering, which is the process of using smaller ships to shuttle crude oil/condensate from onshore terminals out to the VLCC. As part of the lightering, crude oil/condensate is loaded onto the VLCC via ship-to-ship (STS) transfer in off-shore waters with a depth that VLCCs can navigate while fully loaded. Emissions from STS transfer during lightering operations are not regulated by CAA regulations and therefore result in uncontrolled emissions of VOC.

Lightering is the current practice for loading VLCCs with crude oil/condensate for export. The STS transfers that occur during the lightering operations generate similar emissions as will occur during when the proposed SPM buoy system conducts its marine tank vessel loading transfer process. However, lightering generates many other emissions during ship movements that do not occur with the SPM buoy system. When comparing wholistic emissions from the entire lightering process to the entire process associated with use of the proposed SPM buoy system, the benefit of the proposed SPM buoy system is clear. Not only does the proposed SPM buoy system reduce the total amount of air emissions, but the proposed SPM buoy system also reduces ship channel traffic and results in a safer and more efficient process to fully load a VLCC with crude oil/condensate for export.

The additional air emissions impacts of lightering compared to the proposed SPM buoy system are generated from the additional combustion emissions required to shuttle the crude oil/condensate on smaller oil tankers from onshore terminals out to the VLCC. With the proposed SPM buoy system, the only tanker involved is the VLCC and it does not have to come any closer to shore than the location of the proposed SPM buoy system, saving on propulsion fuel use. Furthermore, any emissions from the VLCC will be produced further away from the public than those generated by lightering vessels. The table below shows a comparison of the wholistic potential emissions from lightering and the proposed SPM buoy system.

Table 4-2 – Lightering HAP Emissions Comparison

Method	HAPs (tpy)
Lightering[1]	248
SPM Buoy System[2]	201
Savings from Proposed SPM Design	**47**

1. Accounts for full and partial lightering of VLCC based on a representation of historical lightering operations. HAP emissions represent the emissions from STS loading and any *additional* emissions generated in the lightering process (i.e., Loading of the lightering vessel onshore, propulsion of the lightering vessel, etc.).
2. Represents HAP emissions from SPM buoy system operations only (including product loading, propulsion, and various support vessel emissions).
3. Detailed emission calculations are provided under separate cover in the *Air Quality Information for Environmental Impact Statement, Appendix A*.

5. CASE-BY-CASE MACT ANALYSIS

This section discusses the case-by-case MACT determination for the proposed SPM system. TGTI developed a case-by-case MACT under section 112(g) of the CAA and 40 CFR 63, as referenced in 30 TAC Chapter 116, Subchapter E. This case-by-case application was developed because the SPM buoy system will be a major source of HAP emissions that is not regulated by an existing MACT standard. The rationale for and support of the case-by-case MACT are presented in the following section.

5.1. DEFINITION OF MACT

MACT for new sources is defined in 40 CFR §63.41 follows:

> *"Maximum achievable control technology (MACT) emission limitation for new sources" means the emission limitation which is not less stringent than the emission limitation achieved in practice by the best controlled similar source, and which reflects the maximum degree of reduction in emissions that the permitting authority, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable by the constructed or reconstructed major source.*

This MACT definition applies in two related, but distinct, regulatory contexts for controlling HAP emissions. The first context in which the MACT definition applies is in the development of MACT standards by EPA for specific source categories pursuant to section 112(d) of the CAA. EPA is required to adopt such MACT standards for every listed major source category of HAP emissions through notice and comment rulemaking. The second context in which the MACT definition applies is in regard to the establishment of case-by-case MACT standards for a proposed new (or reconstructed) major source of HAP emissions pursuant to section 112(g) of the CAA. Permitting authorities are required to adopt such case-by-case standards in those instances when EPA has not established a MACT standard under Section 112(d) that applies to the proposed new (or reconstructed) source. This latter case-by-case permitting review is the regulatory context that potentially applies to the proposed SPM system.

5.2. CASE-BY-CASE MACT IMPLEMENTION REGULATIONS

40 CFR §63.43(d) provides the regulatory basis for preparing a Case-by-Case MACT Assessment.

> *(d) Principles of MACT determinations. The following general principles shall be used to make a case-by-case MACT determination concerning construction or reconstruction of a major source under this Rule:*
>
> *(1) The MACT emission limitation or MACT requirements recommended by the applicant and approved by the Division shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined by the Division.*
>
> *(2) Based upon available information, the MACT emission limitation and control technology (including any requirements under Subparagraph (3) of this Paragraph) recommended by the applicant and approved by the Division shall achieve the maximum degree of reduction in emissions of HAP that can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction.*

(3) The owner or operator may recommend a specific design, equipment, work practice, or operational standard, or a combination thereof, and the Director may approve such a standard if the Division specifically determines that it is not feasible to prescribe or enforce an emission limitation under the criteria set forth in Section 112(h)(2) of the federal Clean Air Act.

(4) If the EPA has either proposed a relevant emission standard pursuant to Section 112(d) or 112(h) of the federal Clean Air Act or adopted a presumptive MACT determination for the source category that includes the constructed or reconstructed major source, then the MACT requirements applied to the constructed or reconstructed major source shall have considered those MACT emission limitations and requirements of the proposed standard or presumptive MACT determination.

5.3. SETTING THE MACT LIMIT

40 CFR 63.55 states the requirement for MACT determinations for affected sources subject to case-by-case determination of equivalent emission limitations. 40 CFR 63.55(a)(3) applies to the proposed SPM buoy system and reads as follows:

Each emission limitation for a new affected source must reflect the maximum degree of reduction in emissions of hazardous air pollutants (including a prohibition on such emissions, where achievable) that the permitting authority, taking into consideration the cost of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements, determines is achievable. This limitation must not be less stringent than the emission limitation achieved in practice by the best controlled similar source which must be established by the permitting authority according to the requirements of section 112(d)(3). This limitation must be based upon available information.

Therefore, setting the MACT limit for the proposed SPM buoy system is a two-part exercise. First, the MACT floor for a new source, which is "the emission control achieved in practice by the best controlled similar source" must be established to determine the minimum acceptable level of emissions control. After conducting an exhaustive search of available information, TGTI has determined the applicable MACT floor for the proposed SPM buoy is submerged fill into a ship. Additionally, TGTI identified ship that are loaded should have developed and implemented a VOC Management Plan using submerged fill in accordance with the requirements of Marine Environment Protection Committee Resolution 185(59) (MEPC.185(59)) as the applicable MACT floor for the proposed SPM buoy system. Details of this search are provided in Section 5.3.1. below.

The second step of setting the Case-by-Case MACT standard is referred to as the "beyond-the-floor" (BTF) analysis. The BTF analysis entails an evaluation of whether it is appropriate to set a MACT standard that is more stringent than the applicable floor level of control determined under the first step. A MACT standard stricter than the applicable MACT floor can be appropriate if justified by an evaluation of available methods and technologies for further limiting emissions. TGTI has evaluated beyond-the-floor emissions control technologies and has determined that a BTF MACT limit is not appropriate for the proposed SPM buoy system and that submerged fill represents the maximum degree of reduction in emissions of HAPs that is achievable.

Each of these requirements is briefly discussed below and, where appropriate, the discussion also explains how these requirements apply to the Case-by-Case MACT determination for the proposed SPM buoy system.

5.3.1. Identifying the Best Controlled Similar Source

The first step in determining the MACT floor is to identify the best controlled similar source, as compared to the design, operational, and performance characteristics of the proposed SPM buoy system. TGTI conducted

exhaustive research to identify all potentially similar sources to the proposed SPM buoy. The results of this search are identified in the following sections.

5.3.1.1. MACT Subpart Y Sources

EPA established NESHAP Subpart Y for Marine Vessel Loading Operations in 1995. While NESHAP Subpart Y does not apply to the proposed SPM buoy system, it is the most similar MACT subpart and can offer some insights into the MACT applicability threshold determination for the proposed SPM buoy system.

There is broad authority to "distinguish among classes, types, and sizes of sources" in identifying and evaluating the performance of similar sources for the MACT floor analysis.[1] This step of the analysis – referred to as subcategorization – is an important step in determining the MACT floor, as is discussed in further detail below. Second, Section 112(d)(3) of CAA requires that the MACT floor levels be based on HAP control levels that are "achieved in practice" by the selected best controlled similar source. Courts repeatedly have interpreted this statutory language to require that MACT floors be set at a level that reflects what the best performing source can "achieve under the worst foreseeable conditions."[2]

EPA has subcategorized sources within a general source category in many past MACT rulemakings. In particular, EPA subcategorized sources in their NESHAP Subpart Y rulemakings in 1995 and 2011. In this rulemaking, EPA established the following subcategories for marine vessel loading operations:

- New and existing terminals having throughput of ≥ 1.6 billion liters per year (10 million barrels per year) of gasoline of ≥ 32 billion liters per year (200 million barrels per year) of crude oil;
- Existing major source terminals having emissions of hazardous air pollutants (HAP) of 10/25 tons per year or more from loading of marine tank vessels;
- Existing major source terminals collocated at petroleum refineries having HAP emissions of 10/25 tons per year or more from loading of marine tank vessels; new major source terminals regardless of HAP emissions from marine tank vessel loading (both existing and new sources are regulated under the Gasoline Refineries NESHAP);
- Existing major source terminals regardless of HAP emissions from marine tank vessel loading,
- Existing major source terminals located more than 0.8 kilometers (0.5 miles) offshore;
- New major source terminals located more than 0.8 kilometers (0.5 miles) offshore; and
- Alyeska Pipeline Services Company's Valdez Marine Terminal.

In the case of the proposed SPM buoy system, the subcategories of most interest are those regulating the offshore terminals. In the 1995 development of NESHAP Subpart Y, EPA established no control as the MACT floor for existing offshore terminals and 95% control of HAP emissions for new offshore terminals. These subcategories were again confirmed in 2011 when EPA updated NESHAP Subpart Y regulations adding submerged fill as the new MACT floor for existing offshore terminals and keeping the 95% control requirement for new offshore terminals.

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[1] Section 112(d)(1) of the CAA. This statutory basis for subcategorization was clearly articulated in the Judge Williams' concurring opinion in *Sierra Club v. EPA*, 479 F.3d 875, 884-85 (D.C. Cir. 2007) (hereafter referred to as *"Sierra Club III"*).

[2] *Sierra Club v. EPA*, 167 F.3d 658 (D.C. Cir. 1999) (herein after referred to as "*Sierra Club I*").

In the 1995 rulemaking, EPA estimated that less than 20 offshore terminals with subsea lines were in operation and that none of these facilities controlled emissions from marine tank vessel loading. The EPA received comments that two offshore terminals [just beyond the half mile mark] that do not have subsea lines did control emissions of marine tank vessel loading operations but received no additional information on how or to what degree the emissions were controlled. EPA established a subcategory for offshore terminals based on this very limited information but neglected to consider further additional subcategories for these offshore terminals based on other inherent properties such as types of commodities loaded, the size of the terminal, or the type of operation with which the terminal is associated. As such, the EPA established a MACT floor of 95% control of HAP emissions for new offshore terminals without taking into consideration the additional subcategories of offshore terminals that could be justified. EPA itself admitted that offshore terminals should be broken down into additional subcategories in their summary of public comments and responses on the 1995 NESHAP Subpart Y development.[3]

The proposed SPM system will be unlike any of the sources that were in existence when NESHAP Subpart Y was developed in 1995 and reconsidered in 2011. It will engage in activities that could not be performed during those periods because export of crude oil was banned from 1975 until 2015 as part of the 1975 Energy Policy and Conservation Act. The sole purpose of the proposed SPM buoy system is to fully and completely load VLCC vessels for the export of crude oil/condensate to countries other than the U.S. Therefore, the proposed SPM system will be the only system of its kind in the United States and therefore could not have been considered when the subcategory determinations were conducted in the 1995 and 2011 rulemakings. As explained above, NESHAP Subpart Y is not applicable to the proposed SPM buoy system, and its nature and operational processes make it inherently different than all of the sources that were considered and subcategorized as part of the NESHAP Subpart Y rulemaking. The uniqueness of this source as the only stand-alone SPM DWP capable of directly and fully loading a VLCC for crude oil/condensate export from the United States, demands it be evaluated on a case-by-case basis to determine the level of emission controls that are appropriate for MACT.

5.3.1.2. Santa Barbra Ellwood Marine Terminal

TGTI is aware that the Ellwood Marine Terminal (EMT) in Santa Barbara, California used to operate an SPM buoy system ~0.49 miles off the coast of California for the loading of crude oil and condensate that was produced from the Platform Holly. The EMT was permitted to load barge vessels for the transportation of crude oil from the EMT to refineries throughout California. The EMT has since constructed the infrastructure necessary to transport the crude oil produced by Platform Holly via pipeline and no longer utilizes that SPM buoy system.

When the EMT was in operation, emissions from the loading of the marine barges were controlled by only utilizing two limited-capacity barges Jovalan and Olympic Spirit, which were both equipped with VOC capture and refrigeration control systems. Barge Jovalan (a single hulled barge) was put out of service and replaced by the barge Olympic Spirit (a double hulled barge) in 2010. Neither barge has self-propulsion capabilities and are therefore transported by tug boat to and from each destination. Barge Jovalan had a capacity of 56,000 bbl and Barge Olympic Spirit had a capacity of 80,360. Both barges were loaded at a maximum loading rate of 4,200 bbl/hr from the EMT.

The EMT is not a similar source to the proposed SPM buoy system. The most obvious difference is the major difference in size of the two systems. From 1998 through 2009 the maximum annual throughput of the EMT was

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[3] *Federal Standards for Marine Tank Vessel Loading Operations and National Emission Standards for Hazardous Air Pollutants for Marine Tank Vessel Loading Operations. Technical Support Document for Final Standards: Summary of Public Comments and Responses*. EPA-453/R-95-014. July 1995. Pg. 2-69.

just under 1.4 MMbbl of crude oil loaded onto barges (with a maximum hourly loading rate of 4,200 bbl/hr). The proposed SPM buoy system will have a capacity that is orders of magnitude larger than this with a potential annual throughput of 192 MMbbl/yr and a maximum hourly loading rate of 60,000 bbl/hr. The proposed SPM buoy system will also be located much further off the coast than the EMT, around 14 miles offshore versus 0.49 miles, and will load VLCCs which have a 2 MMbbl capacity.

Additionally, there are no VLCCs in operation that have onboard VOC capture and control technology like the Barges Jovalan and Olympic Spirit used. Even if there were a single VLCC that had onboard VOC capture and control technology, like the two barges used at the EMT for transporting crude, that could be exclusively loaded at the proposed SPM buoy system, the logistics of exporting crude throughout the world would make this an infeasible option. The EMT's two different barges were only used to transport relatively small amounts of crude short distances to refineries in northern or southern California. That practice was totally different from the world-wide deliveries of millions of barrels the VLCC vessels will make after being loaded for those proposes at the SPM buoy system. For these reasons, the EMT is not a similar source to the proposed SPM buoy system, and the EMT's use of small, dedicated barges to control emissions is not considered in the development of the MACT floor for the proposed SPM buoy system.

5.3.1.3. North Sea Shuttle Vessels

Through TGTI's research, they also became aware of plans to construct tanker shuttles in the North Sea that had onboard VOC capture and control. Wartsila and Teekay Offshore Partners have developed and started construction of 4 Suezmax-sized (850,000 bbl capacity) shuttle vessels based on the Shuttle Spirit design.[4] The Shuttle Spirit design is a new shuttle tanker design that allows the tanker to operate using both liquefied natural gas (LNG) as the primary fuel along with VOC that is captured from the oil cargo tanks.[5] The VOC recovery plant uses compression and cooling phases to liquefy the heavier hydrocarbon to be stored in a tank on the deck of the ship.

These sources are not similar to or applicable to the proposed SPM buoy system because of their size differences. The proposed SPM buoy system will only be able to load VLCC vessels with a capacity of 2 MMbbl. The Suezmax-sized vessels being built will only have a capacity of 850,000 bbl and could not load at the proposed SPM buoy system because the cranes aboard Suezmax-sized vessels are not large enough to connect to the proposed SPM buoy system properly. The purpose of the proposed SPM buoy system is to enable full and complete loading of a VLCC vessel for crude oil/condensate export from the United States. Full and complete loading of a VLCC is not possible at onshore terminals since VLCCs exceed the size restrictions on vessels that can navigate to onshore terminals. Therefore, because the proposed SPM buoy system is not designed to load Suezmax-sized vessels, a future-built Suezmax-sized vessel with a VOC recovery plant is not a similar source to the proposed SPM buoy system.

5.3.2. Achieved in Practice

Once the best controlled technology in use by a similar source is identified, the next step is to establish what emissions limitation can be achieved in practice with that control technology. Since submerged loading is not a control technology but rather a standard operating practice, there are no accompanying emissions limitations associated with the use of submerged loading. As provided for in 40 CFR § 63.43(d)(3), a specific design, equipment, work practice, or operational standard, or combination thereof, can be approved in lieu of an

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[4] https://www.teekay.com/blog/2017/11/28/teekay-offshore-partners-places-order-for-two-additional-shuttle-tankers/

[5] https://www.wartsila.com/twentyfour7/in-detail/the-new-shuttle-tanker

emission limitation if it is not feasible to prescribe or enforce an emission limitation under the criteria set forth in Section 112(h)(2) of the Clean Air Act.

Submerged loading in the case of the proposed SPM buoy system is a loading procedure by which the discharge of crude oil/condensate into the VLCC tanks is located at or below the surface of the crude oil/condensate in the vessel. By discharging the crude oil/condensate into the hold at a point below the surface of the liquid, VOC emissions are mitigated compared to splash loading because the surface of the cargo is not disturbed in submerged loading. Compared to splash loading, this minimizes the generation of VOC emissions because it reduces the surface area liquid/vapor interface and thus minimizes the volatilization of hydrocarbons from the liquid.

In addition to submerged loading as a method of VOC control, Regulation 15.6 of the International Convention for the Prevention of Pollution from Ships (MARPOL) Annex VI requires that all tankers carrying crude oil have an approved and effectively implemented ship specific VOC Management Plan covering at least the points given in the regulation. Guidelines for the development of VOC Management Plans is given in MEPC.185(59) and additional information on systems and operations of VOC Management Plans is given in MEPC.1/Circ.680. For reference, MEPC.185(59) and MEPC.1/Circ.680 have been provided as Attachments 1 and 2, respectively.

The VOC Management Plan is a ship-specific management plan designed to ensure that the operation of a tanker, to which Regulation 15 of MARPOL Annex VI applies, prevents or minimizes VOC emissions to the extent possible. To comply with the plan, the loading and carriage of cargoes which generate VOC emissions should be evaluated and procedures written to ensure that the operations of a ship follow best management practices for preventing and minimizing VOC emissions to the extent possible. With respect to the loading operations at the proposed SPM buoy system, Rule 1.4. of the VOC Management Plan Guideline (MEPC.185(59)) states that while maintaining the safety of the ship, the VOC Management Plan should encourage and set forth the following best management practices as appropriate:

1. The loading procedures should take into account potential gas releases due to low pressure and, where possible, the routing of oil from crude oil manifolds into the tanks should be done so as to avoid or minimize excessive throttling and high flow velocity in pipes;
2. The ship should define a target operating pressure for the cargo tanks. This pressure should be as high as safely possible and the ship should aim to maintain tanks at this level during the loading and carriage of relevant cargo;
3. When venting to reduce tank pressure is required, the decrease in the pressure in the tanks should be as small as possible to maintain the tank pressure as high as possible;
4. The amount of inert gas added should be minimized. Increasing tank pressure by adding inert gas does not prevent VOC release but it may increase venting and therefore increase VOC emissions.

Technical information for the development of VOC Management Plans for tankers carrying crude oil are provided in MEPC.1/Circ.680 (Attachment 2).

Since VOC Management Plans are ship-specific plans, the emission rate of HAPs will vary depending on the specific ship being loaded. Therefore it is not practical to set an emissions limitation for the proposed SPM buoy system. Instead, the following conditions are appropriate as the MACT floor limitation for the proposed SPM buoy system:

> *Submerged loading onto vessels which have onboard and implement a VOC management plan that complies with the requirements of MEPC.185(59).*

5.3.3. Beyond the MACT Floor

Having identified the MACT floor, the next step is to determine if BTF control measures are justified. To date, no SPM buoy systems similar to the proposed SPM buoy system control HAP emissions further than via submerged loading. Not only is this true throughout the waters off the United States, but it is also true for all SPM buoy systems throughout the world. Nonetheless, TGTI has evaluated controlling the loading emissions with a vapor combustion unit (VCU) or a vapor recover unit (VRU) but has eliminated both control technologies from consideration because of the technical and operational infeasibility.

While both VCU and VRU technology have been well established at on shore terminals, the challenges facing implementation of these technologies at a source similar to the proposed SPM buoy system are significantly greater than compared to onshore facilities. In fact, there may be technical challenges that are not yet defined as the technologies identified have never been applied to a source like the proposed SPM buoy system.

5.3.3.1. Vapor Combustion Unit

A VCU captures vapors emitted during loading operations and routes them to a combustion device for control. While this control method reduces the emissions of VOC, it creates collateral emissions increases of pollutants from combustion. Given the location of the proposed SPM buoy system, there is not a suitable location for the VCU equipment. A VCU would require a separate platform or the means for captured vapors to be routed back to an onshore VCU.

Nonetheless, TGTI identified a VCU as a potential control technology because of its demonstrated ability to control emissions from land-based terminals. Though VCUs are demonstrated for land-based terminals, they have not been demonstrated as a control technology on sources similar to the proposed SPM buoy system. Application of VCU technology to the proposed SPM buoy system faces several inherent design challenges when compared to their application at land-based facilities, as identified below.

- Space Limitations
  - The proposed SPM buoy system is a single buoy floating roughly 14 miles offshore. The proposed SPM buoy system is not physically capable of housing equipment necessary for operation of a VCU. Modifications to the SPM buoy system to accommodate a VCU at the source is not a technically feasible option. Such modification would require the design and construction of a novel platform and vapor collection system that has not been demonstrated before. Such a platform would have to be located outside of the designated “swing circle” around the SPM buoy. The swing circle is the area around the SPM buoy in which the ship being loading is allowed to weathervane, or swing, around the SPM buoy during loading. This process is essential to the safety and design of the SPM buoy system as it allows the ship to optimally position itself around the SPM buoy to minimize the forces on the SPM buoy system. To allow for this movement pattern, a platform housing a VCU would have to be located safely outside of this circle, which is typically on the order of 1,500 to 2,000 ft in all directions. The vapor collection system would consist of a vapor collection line back to the SPM buoy, down to a subsea pipeline, then out to the VCU platform via this subsea pipeline. A vapor collection system of this manner has not been demonstrated in practice.
- Safety and Reliability Considerations Due to Variability in Operating Conditions

- As described above, the vapor collection system that would be required for a VCU at the SPM buoy would be a new and unique system that is not currently in place at an SPM buoy system. The distance that the vapor collection line will have to travel underwater presents a reliability concern for the system. The long distance traversed by the vapor collection lines underwater increases the chances of condensed vapors in the vapor collection lines which would create both operational reliability and safety concerns. The other main concern is the constantly variable ocean conditions. Since the VCU equipment would have to be located on a floating platform, the natural motion of ocean waves will disturb the operation of the VCU and lead to unavoidable safety and reliability concerns.

Given the technical issues cited above, VCU control technology is not an "applicable" technology to the proposed SPM buoy system since it cannot reasonably be installed and operated on the source type under consideration. Therefore, VCU technology is eliminated from consideration as a technically infeasible control option for BTF MACT control.

5.3.3.2. Vapor Recovery Unit

A VRU captures vapors emitted during loading operations then routes them to VRU equipment to be absorbed and reintroduced into the process. The captured vapors are converted back into a liquid by using refrigeration, absorption, adsorption, and/or compression. Given the location of the proposed SPM buoy system, there is not a suitable location for the VRU equipment. A VRU would require a separate platform or the means for captured vapors to be routed back to an onshore VRU.

TGTI identified a VRU as a potential control technology because of its demonstrated ability to control emissions from land-based terminals. Though VRUs are demonstrated for land-based terminals, they have not been demonstrated as a control technology on sources similar to the SPM buoy system. Application of VRU technology to the proposed SPM buoy system faces several design challenges when compared to their application at land-based facilities, as identified below.

- Space Limitations
  - The proposed SPM buoy system is a single buoy floating roughly 14 miles offshore. The proposed SPM buoy system is not physically capable of housing equipment necessary for operation of a VRU. Modifications to the SPM buoy system to accommodate a VRU at the source is not a technically feasible option. Such modification would require the design and construction of a novel platform and vapor collection system that has not been demonstrated before. Such a platform would have to be located outside of the designated "swing circle" around the SPM buoy. The swing circle is the area around the SPM buoy in which the ship being loading is allowed to weathervane, or swing, around the SPM buoy during loading. This process is essential to the safety and design of the SPM buoy system as it allows the ship to optimally position itself around the SPM buoy to minimize the forces on the SPM buoy system. To allow for this movement pattern, a platform housing a VRU would have to be located safely outside of this circle, which is typically on the order of 1,500 to 2,000 ft in all directions. The vapor collection system would consist of a vapor collection line back to the SPM buoy, down to a subsea pipeline, then out to the VRU platform via this subsea pipeline. A vapor collection system of this manner has not been demonstrated in practice.

- Safety and Reliability Considerations Due to Variability in Operating Conditions
  - As described above, the vapor collection system that would be required for a VRU at the SPM buoy would be a new and unique system that is not currently in place at an SPM buoy system. The distance that the vapor collection line will have to travel underwater presents a reliability concern for the system. The long distance traversed by the vapor collection lines underwater increases the chances of condensed vapors in the vapor collection lines which would create both operational reliability and safety concerns. The other main concern is the constantly variable ocean conditions. Since the VRU equipment would have to be located on a floating platform, the natural motion of ocean waves will disturb the operation of the VRU and lead to unavoidable safety and reliability concerns. Traditional VRU control technology uses a tall absorber tower that, because of the height, will experience large oscillations at the tip, even from relatively small movement at the base from waves.

Given the technical issues cited above, VRU control technology is not an "applicable" technology to the proposed SPM buoy system since it cannot be reasonably be installed and operated on the source type under consideration. Therefore, traditional VRU technology is eliminated from consideration as a technically infeasible control option for BTF MACT control.

5.3.4. Selected Control Technology

TGTI has concluded that the following meet MACT under 112(g) for HAP emissions from the proposed SPM buoy system:

> *Submerged loading onto vessels which have onboard and implement a VOC management plan that complies with the requirements of MEPC.185(59).*

ATTACHMENT 1 – MEPC.185(59) – GUIDANCE FOR VOC MANAGEMENT PLANS

ANNEX 10

RESOLUTION MEPC.185(59)
Adopted on 17 July 2009

GUIDELINES FOR THE DEVELOPMENT OF A VOC MANAGEMENT PLAN

THE MARINE ENVIRONMENT PROTECTION COMMITTEE,

RECALLING Article 38(a) of the Convention on the International Maritime Organization concerning the functions of the Marine Environment Protection Committee conferred upon it by international conventions for the prevention and control of marine pollution,

NOTING that the revised MARPOL Annex VI was adopted by resolution MEPC.176(58) which is expected to enter into force on 1 July 2010,

NOTING ALSO that regulation 15.6 of the revised Annex VI requires a tanker carrying crude oil to have onboard and implement a VOC management plan approved by the Administration, and that such a plan shall be prepared taking into account the guidelines developed by the Organization,

HAVING CONSIDERED the draft Guidelines for the development of a VOC management plan prepared by the Sub-Committee on Bulk Liquids and Gases at its thirteenth session,

1. ADOPTS the Guidelines for the development of a VOC management plan, as set out in the Annex to this resolution; and

2. INVITES Governments to apply the Guidelines from 1 July 2010.

ANNEX

GUIDELINES FOR THE DEVELOPMENT OF A VOC MANAGEMENT PLAN

1 Objectives

.1 The purpose of the VOC management plan is to ensure that the operation of a tanker, to which regulation 15 of MARPOL Annex VI applies, prevents or minimizes VOC emissions to the extent possible.

.2 Emissions of VOCs can be prevented or minimized by:

.1 optimizing operational procedures to minimize the release of VOC emissions; and/or

.2 using devices, equipment, or design changes to prevent or minimize VOC emissions.

.3 To comply with this plan, the loading and carriage of cargoes which generate VOC emissions should be evaluated and procedures written to ensure that the operations of a ship follow best management practices for preventing or minimizing VOC emissions to the extent possible. If devices, equipment, or design changes are implemented to prevent or minimize VOC emissions, they shall also be incorporated and described in the VOC management plan as appropriate.

.4 While maintaining the safety of the ship, the VOC management plan should encourage and, as appropriate, set forth the following best management practices:

.1 the loading procedures should take into account potential gas releases due to low pressure and, where possible, the routing of oil from crude oil manifolds into the tanks should be done so as to avoid or minimize excessive throttling and high flow velocity in pipes;

.2 the ship should define a target operating pressure for the cargo tanks. This pressure should be as high as safely possible and the ship should aim to maintain tanks at this level during the loading and carriage of relevant cargo;

.3 when venting to reduce tank pressure is required, the decrease in the pressure in the tanks should be as small as possible to maintain the tank pressure as high as possible;

.4 the amount of inert gas added should be minimized. Increasing tank pressure by adding inert gas does not prevent VOC release but it may increase venting and therefore increased VOC emissions; and

.5 when crude oil washing is considered, its effect on VOC emissions should be taken into account. VOC emissions can be reduced by shortening the duration of the washing or by using a closed cycle crude oil washing programme.

2 Additional considerations

.1 A person in charge of carrying out the plan

.1 A person shall be designated in the VOC management plan to be responsible for implementing the plan and that person may assign appropriate personnel to carry out the relevant tasks;

.2 Procedures for preventing or minimizing VOC emissions

.1 Ship-specific procedures should be written or modified to address relevant VOC emissions, such as the following operations:

.1 Loading;

.2 Carriage of relevant cargo; and

.3 Crude oil washing;

.2 If the ship is equipped with VOC reduction devices or equipment, the use of these devices or equipment should be incorporated into the above procedures as appropriate.

.3 Training

.1 The plan should describe the training programmes to facilitate best management practices for the ship to prevent or minimize VOC emissions.

***

ATTACHMENT 2 - MEPC.1/CIRC.680

INTERNATIONAL MARITIME ORGANIZATION
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E

Ref. T5/1.01

MEPC.1/Circ.680
27 July 2009

TECHNICAL INFORMATION ON SYSTEMS AND OPERATION TO ASSIST DEVELOPMENT OF VOC MANAGEMENT PLANS

1 The Marine Environment Protection Committee, at its fifty-ninth session (13 to 17 July 2009), approved the Guidelines for the Development of a Volatile Organic Compound (VOC) Management Plan for tankers carrying crude oil (resolution MEPC.185(59)).

2 In conjunction with consideration of the guidelines, MEPC 59 agreed that additional technical information on vapour pressure control systems and their operation would assist the industry in development of VOC management plans. Therefore, MEPC 59 agreed to the technical information on systems and operation to assist development of VOC management plans for tankers carrying crude oil, as set out in the annex to this document.

3 The technical information addresses the general equipment and systems involved, their operation and conditions on board a crude oil tanker with respect to the formation and emission of Volatile Organic Compounds (VOC) as well as the ability to control VOC formation and emissions.

4 Member Governments are invited to bring this circular to the attention of their Administrations, relevant shipping organizations, recognized organizations, shipping companies and other stakeholders concerned and encourage them to take it into account when applying the Guidelines for the development of a VOC management plan for crude oil tankers.

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ANNEX

TECHNICAL INFORMATION ON VAPOUR PRESSURE CONTROL SYSTEMS AND THEIR OPERATION TO ASSIST DEVELOPMENT OF VOC MANAGEMENT PLANS FOR TANKERS CARRYING CRUDE OIL

Introduction

This technical information is compiled pursuant to the requirements in MARPOL Annex VI Regulation 15.6, and describes the general equipment, operations and conditions onboard a crude oil tanker with respect to the emission and ability to control Volatile Organic Compound (VOC) emissions.

The Guidelines for the development of a VOC management plan state:

1 Objectives

.1 The purpose of the VOC management plan is to ensure that the operation of a tanker, to which regulation 15 of MARPOL Annex VI applies, prevents or minimizes VOC emissions to the extent possible.

.2 Emissions of VOCs can be prevented or minimized by:

.1 optimizing operational procedures to minimize the release of VOC emissions; and/or

.2 using devices, equipment, or design changes to prevent or minimize VOC emissions.

.3 To comply with this plan, the loading and carriage of cargoes which generate VOC emissions should be evaluated and procedures written to ensure that the operations of a ship follow best management practices for preventing or minimizing VOC emissions to the extent possible. If devices, equipment, or design changes are implemented to prevent or minimize VOC emissions, they shall also be incorporated and described in the VOC management plan as appropriate.

.4 While maintaining the safety of the ship, the VOC management plan should encourage and, as appropriate, set forth the following best management practices:

.1 the loading procedures should take into account potential gas releases due to low pressure and, where possible, the routing of oil from crude oil manifolds into the tanks should be done so as to avoid or minimize excessive throttling and high flow velocity in pipes;

.2 the ship should define a target operating pressure for the cargo tanks. This pressure should be as high as safely possible and the ship should aim to maintain tanks at this level during the loading and carriage of relevant cargo;

.3 when venting to reduce tank pressure is required, the decrease in the pressure in the tanks should be as small as possible to maintain the tank pressure as high as possible;

.4 the amount of inert gas added should be minimized. Increasing tank pressure by adding inert gas does not prevent VOC release but it may increase venting and therefore increased VOC emissions; and

.5 when crude oil washing is considered, its effect on VOC emissions should be taken into account. VOC emissions can be reduced by shortening the duration of the washing or by using a closed cycle crude oil washing programme.

2 Additional considerations

.1 A person in charge of carrying out the plan

.1 A person shall be designated in the VOC management plan to be responsible for implementing the plan and that person may assign appropriate personnel to carry out the relevant tasks;

.2 Procedures for preventing or minimizing VOC emissions

.1 Ship-specific procedures should be written or modified to address relevant VOC emissions, such as the following operations:

.1 Loading;

.2 Carriage of relevant cargo; and

.3 Crude oil washing;

.2 If the ship is equipped with VOC reduction devices or equipment, the use of these devices or equipment should be incorporated into the above procedures as appropriate.

.3 Training

.1 The plan should describe the training programmes to facilitate best management practices for the ship to prevent or minimize VOC emissions.

Section 1 – The hull and its pressure limitations

1.1 Allowable cargo tank ullage pressure

1.1.1 The cargo tank structure is designed to withstand a range of design loads and parts of the tank structure will also contribute to the global longitudinal strength of the ship. The classification societies' specified load conditions and loads are applied in verification of the structural design. One such load is the combined pressure from the liquid cargo and the tank ullage pressure. The tank ullage pressure is to be minimum 25 kN/m^2 or the opening pressure of the pressure relief device (P/V valve), whichever is greater. Accordingly, the maximum allowable ullage pressure in a standard tanker is typically interpreted as 25 kN/m^2 (i.e. approximately 2,550 mmWG). It should however be noted that global strength considerations and the impact of other design loads may imply that actual allowable pressure could be higher.

1.1.2 In terms of under pressure, SOLAS regulation II-2/11.6 indicates an allowable under pressure of -700 mmWG. From a structural point of view, the maximum allowable tank under pressure is presumably lower.

1.1.3 Exceeding the maximum allowable pressures could lead to structural failures. If such a structural failure results in opening of the tank structure to atmosphere, uncontrolled VOC emissions will occur together with the possibility of oil pollution to the seas. Further, it could result in loss of inert gas protection with subsequent hazards related to fire and explosion.

1.2 Typical cargo tank venting systems

1.2.1 The design of cargo tank venting and inert gas systems is governed by SOLAS regulation II-2/11.6 and 5. Most crude oil tankers have a common cargo tank venting and inert gas main pipeline which is also used for vapour emission control (ref. section 4). Branches to each cargo tank are provided with isolation valves and blanking arrangements. The isolation valves and blanks are typically only used in connection with tank entry. SOLAS chapter II-2 requires that the isolation valves are to be provided with locking arrangements to prevent inadvertent closing/opening of said tanks. The cargo tank venting/inert gas main is connected to a mast riser. The mast riser has a minimum height of 6 metres with an IMO approved flame arrestor at its outlet. An isolation valve is provided between the cargo tank venting/inert gas main and the mast riser. Some designs have a small capacity pressure/vacuum valve fitted in a bypass across the isolation valve. This latter enables thermal breathing from cargo tanks when the isolation valve is closed. A liquid-filled P/V breaker is typically connected to the cargo tank venting/inert gas main. The P/V breaker has a capacity to accommodate the gas flow from cargo tanks during loading (125% of the loading rate and discharge rate). The cargo tank venting/inert gas main is typically used during loading and discharging operations. During loading the mast riser valve is open (unless vapour emission control is performed) and VOC is expelled to air. During discharge the same valve is closed and inert gas used to replace the tank atmosphere. The cargo tank venting/inert gas main is also used during voyage but the mast riser valve will be operated only in the event of increasing ullage pressure.

1.2.2 In addition to the common cargo tank venting/inert gas main, each cargo tank is required to have a pressure/vacuum relief device for thermal breathing in the event the cargo tank is isolated from the common cargo tank venting/inert gas main. Although classification societies accept that these devices have the capacity to accommodate gas volumes resulting from variations in cargo temperature only (i.e. thermal breathing), latest industry practices have led to the installation of devices with the capacity to accommodate the full gas flow from loading of cargo tanks.

1.3 Typical settings of pressure/vacuum relief devices

1.3.1 Although the design pressure of cargo tanks is typically +2,500 mmWG and -700 mmWG, the typical setting of pressure/vacuum valves on crude tankers is +1,400 mmWG and -350 mmWG.

1.3.2 The typical settings of the P/V breakers are +1,800 mmWG and -500 mmWG. It should be noted that for liquid filled P/V breakers, the settings have to take into account ship movement (rolling and pitching) as specified by the classification societies.

Section 2 – Crude Oil Tanker Pressure control/release systems

2.1 Introduction

2.1.1 Traditionally, vapour release from crude oil tankers occurs on three discrete occasions, they being: during loading, during the loaded voyage to the discharge port, and during the ballasting of cargo tanks at the discharge port.

2.1.2 Since the introduction of the International Convention for the Prevention of Pollution from Ships together with its Protocol in 1978 (MARPOL), tankers built after 1 June 1982 (regulation 18), termed MARPOL tankers, are all designed with the required totally segregated (designated) ballast tanks. With these regulations in force, cargo tanks are never used for the loading of ballast, except on very rare occasions for bad weather purposes where one of the Crude Oil Washed cargo tanks is dedicated to take in ballast water. Therefore, the displacement of vapour from the relevant crude oil cargo tank at the discharge port has ceased to occur for the MARPOL compliant type tankers. Given this situation then, only two occasions remain where vapour emissions from crude oil tankers generally occur, namely on loading and during the transportation of the cargo.

2.2 Load Port Displacement of VOC

2.2.1 Displacement of crude oil cargo vapours at the loading port continues to occur. The reasons for the existence of these volumes of this displaced, but co-mingled[1], vapour must be subdivided and attributed to two discrete tanker operations; namely existing vapour in the cargo tank system before loading and, the evolved vapour created during the loading programme.

2.2.2 The first portion of the vapour displaced from the cargo tanks to be considered is that from the evolved vapour generated during the previous discharge programme and in particular that vapour generated as a result of the Crude Oil Washing of the cargo tanks. The concentration of this proportion of vapour within the co-mingled gas mixture within a cargo tank can be

[1] The vapour emissions on loading are a mixture of hydrocarbon vapours and the inert gas introduced into the cargo tank to achieve a positive pressure within the cargo tank system.

determined prior to commencement of the loading process. The second portion of vapour displaced is that that develops or evolves during the loading programme itself. This vapour evolves as a result of, both, the turbulence generated in the cargo tanks due to the volumetric rate of loading and the pressure differentials within the loading pipeline system creating a degree of "flashing" of the vapour from the incoming crude oil.

2.2.3 To illustrate the extent of these gases within a cargo tank system on a tanker during a loading process, Figure 2.1 below shows the measurements of hydrocarbon vapour concentrations as taken from a tanker during its loading programme. The "X" axis of the graph records the percent status of loading of the tanker whereas the "Y" axis records the percentage of hydrocarbon vapour (VOC) concentration. The graph primarily records the total hydrocarbon gas concentration at the differing percentages of loading of the cargo tanks. However, this total figure is then mathematically proportioned and subdivided, taking into consideration the diminishing size of the vapour volume in the cargo tanks, into the two concentrations of vapours, namely those present at the commencement of loading (in the event approximately 4% of the total tank vapour volume) and the concentration of vapours that evolve as a result of the loading process.

2.2.4 These vapours are displaced by the incoming cargo volumes, throughout the loading period, and released through the ship's vapour pipeline system (inert gas pipeline) to atmosphere via the ship's mast riser. In order to prevent excess pressures within the cargo tank system the isolation/control valve to the mast riser is fully opened at the commencement of loading and remains opened until completion of loading. Once the mast riser valve is shut and loading is completed, the necessary "in tank" positive pressure is achieved to prevent any form of air/oxygen entry into the cargo tank vapour system as is required by the SOLAS regulations.

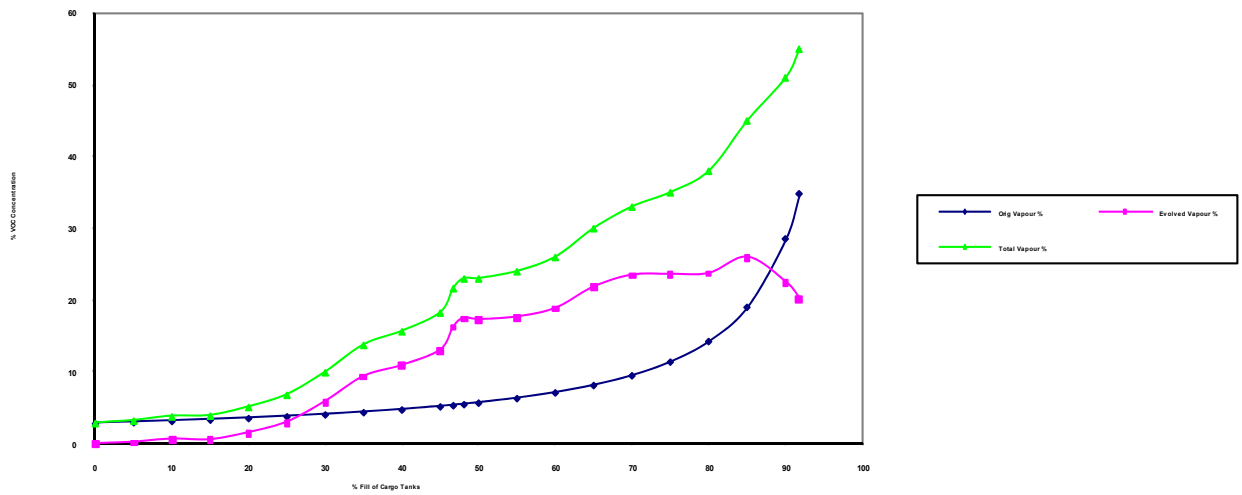

Figure 2.1 – Hydrocarbon vapour concentration in the vapour phase during a loading

2.2.5 In Figure 2.2 below, a photograph shows the deck of a tanker and highlights the relevant pressure control and release mechanisms, namely the vessel's mast riser, the individual tank Pressure/Vacuum (P/V) valves and the secondary safety mechanism of the P/V breaker. These mechanisms will be explained further in this section.

Figure 2.2 – Main Cargo Deck of a Crude Oil Tanker

2.2.6 Typically a normal loading programme will take about 24 hours for a VLCC with a volumetric rate of loading of up to 20,000 m^3/hour. The mast riser is normally used during loading for tank vapour pressure control. Its exit location, being at least 6 metres above the deck, allows for the free flow of the vapours displaced from the cargo tanks by the incoming liquid crude oil at the rate of loading of the cargo. The rate of displacement of VOC vapours from the cargo tank system will be the same as the loading rate but the concentration of VOC vapours in the displaced stream will be greater dependent upon the extent and rate of evolution of VOC vapours (vapour growth) from the incoming cargo that would add to the volume of gas/vapour mixture already existent in the cargo tank prior to loading, as shown in Figure 2.1 above.

2.3 VOC release during the voyage

2.3.1 During the voyage, the temperature of the gases/vapours in the ullage space of the cargo tanks and the liquid cargo varies. The gas phase consists of a mixture of unsaturated gases (Inert Gas – for tank safety and protection) and saturated vapours (evolved hydrocarbon vapours from the cargo). The temperature of the gas phase of the tank varies diurnally with its maximum temperature being achieved by mid afternoon and its coolest temperature in the early hours of the morning. The liquid phase temperature varies very much slower and is dependent upon both the hull design and the temperature of the surrounding seawater.

2.3.2 Figure 2.3 below records, as an example, the vapour pressure and cargo temperature data of a reported voyage for a single hulled (but segregated ballast) tanker. The graph records on the "X" axis the days of the voyage whereas the "Y" axis records both the cargo temperature (^oC) and the pressure (mmWG) within the vapour phase of the cargo tank system. Superimposed upon the graph is both the normal operational release pressure as well as the P/V valve opening

pressure levels. The vapour pressure readings were recorded every four hours whereas the cargo liquid temperature readings (blue) were recorded daily.

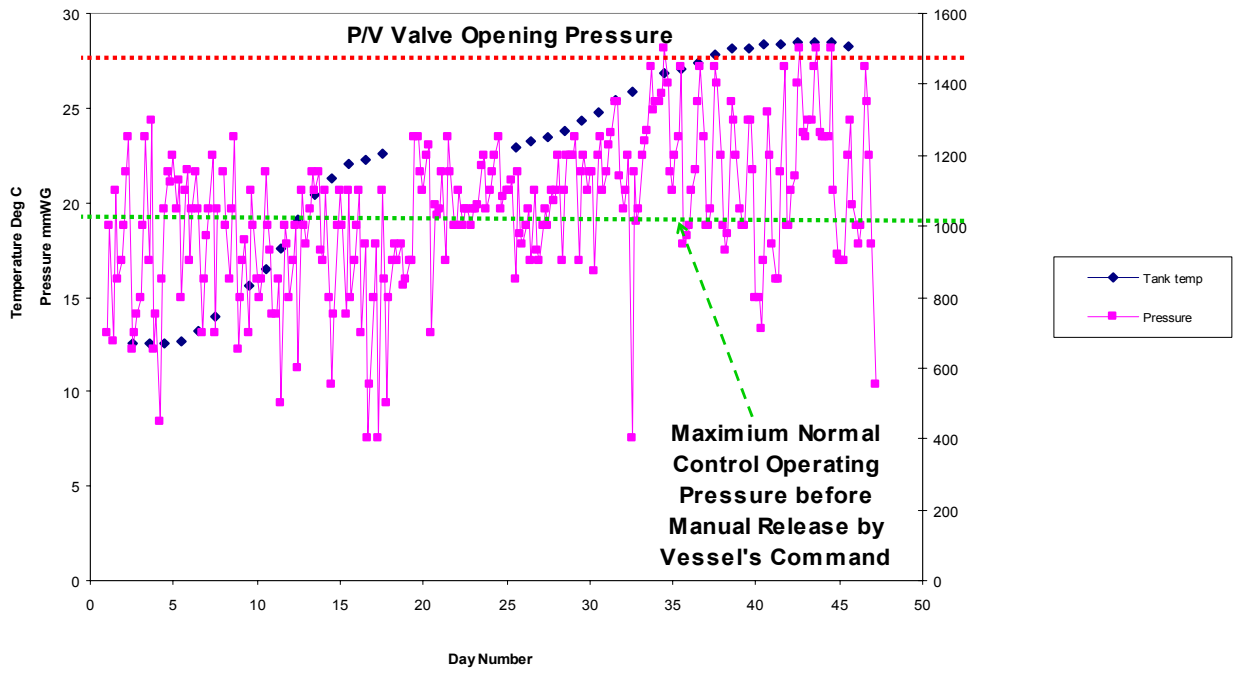

Figure 2.3 – Temperature and Pressure profile for a crude oil voyage

2.3.3 The double hulled construction of a crude oil tanker has a void/ballast space located between the cargo tank and the outer hull, this causes the temperature of the liquid cargo to remain closer to the temperature of the cargo upon loading for a longer period due to the so called "Thermos Effect" or heat loss insulation created by the void or empty ballast space. The cargo temperature profile, as shown in Figure 2.3, reflects the expected changes to temperature for a cargo carried on board a single hulled vessel where the impact of the seawater temperature upon the cargo is more apparent. This aspect can be more clearly seen in Figure 2.3 for the early/interim days of the 47-day voyage from North Sea to the Far East.

2.4 A Crude Oil Tanker's vapour pressure control mechanisms

2.4.1 A crude oil tanker is designed and constructed to withstand high vapour pressures up to a certain value. In order to protect the vessel's structure against excessive pressures, two differing levels of safety mechanisms are installed to control and limit the pressures exerted in the vapour phase of the cargo system. The installation of both these systems is a requirement within the International Convention for the Safety of Life at Sea (SOLAS). These mechanisms are:

.1 the individual tank Pressure/Vacuum (P/V) valve; and

.2 the common Pressure/Vacuum (P/V) breaker.

2.4.2 The P/V valve is the primary mechanism for the protection from cargo tank over pressure. The design and operational requirements of the P/V valves are set out in the ISO 5364:2000 standard but the opening and closing pressure setting of the individual valves is set in accordance with the designed tolerance of the relevant structure having applied the necessary safety margins.

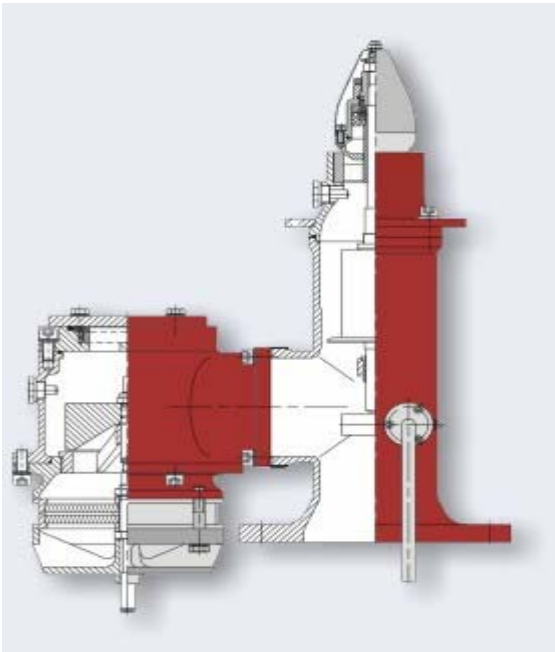

Figure 2.4 – A design and construction of a P/V valve[2]

2.4.3 A design of a P/V valve may be seen in Figure 2.4 above. The valve is fitted to a vertical pipeline connected directly to the vapour space of a cargo tank (see Figure 2.2 above). The valve consists of two sections, namely the vacuum protection section on the left hand side of the valve as shown and the pressure control mechanism of the right hand side. Both mechanisms rely upon a weighted diaphragm that will be lifted when the pre-designed pressures are met. On the pressure side of the valve the exit nozzle is designed such that the exit velocity of the vapours reach the required velocity so as to maintain the deck working area clear of hydrocarbon vapours.

2.4.4 Each cargo tank is normally equipped with its valve so that full protection is available, should the individual cargo tank be isolated from the main common vapour system on board the tanker. The typical pressure setting for a P/V valve is traditionally measured in millimetres of water gauge and would be in the range from 1,400 to 1,800 mmWG. These valves are supported on a connecting pipeline to the tank's atmosphere by a 100 to 150 mm diameter pipeline and located at least 2 metres above the deck. Due to the requirements to prevent mechanical damage to these valves the closing pressure is controlled by a damping mechanism (to prevent hammering of the valve). As a result of the damping mechanism the closing pressure of the valve will vary but will be in the range of 400-800 mmWG.

[2] Courtesy Pres-Vac Engineering A/S: www.pres-vac.com.

2.4.5 Supporting the over pressure safety system of the P/V valve is the secondary safety mechanism of the P/V breaker. In the event of a rapid pressure fluctuation within the common vapour system the P/V breaker is available to relieve such an over pressure. The single P/V breaker is located on the common vapour pipeline, serving all the cargo tank branch pipelines, which ends at the vessel's mast riser (see Figure 2.2).

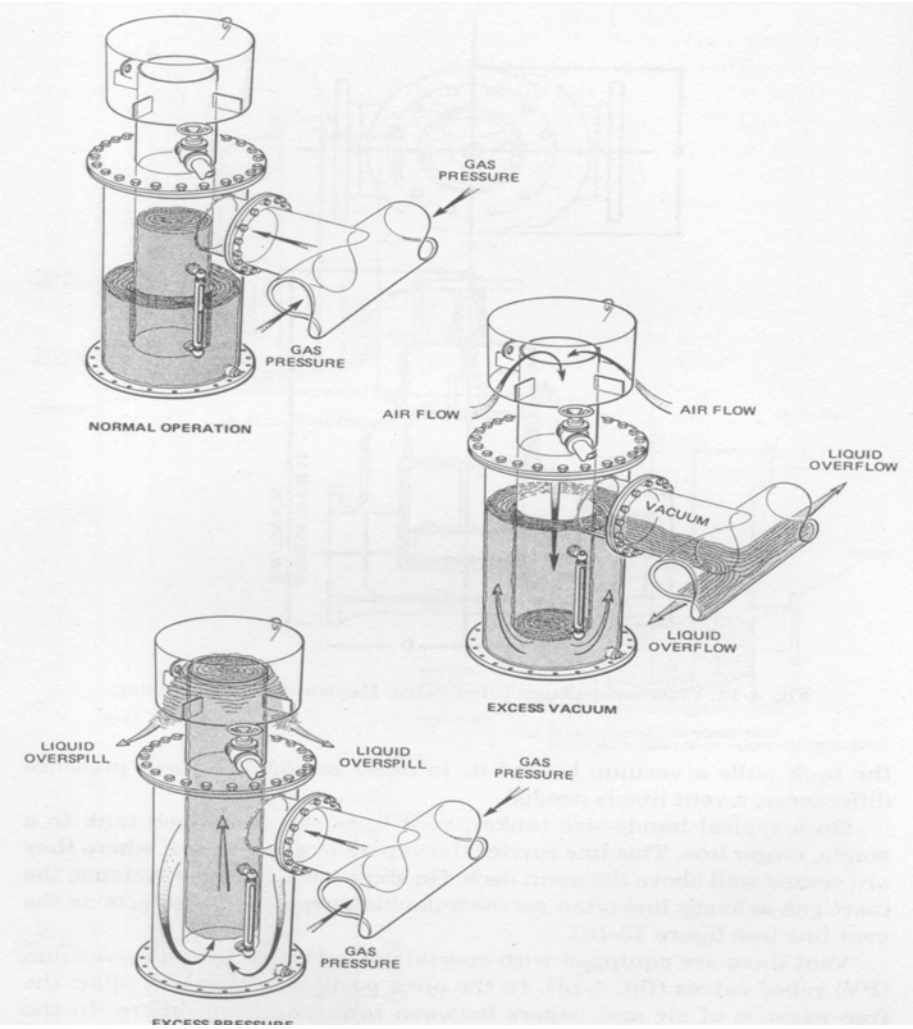

Figure 2.5 – The design and operation of a P/V breaker[3]

2.4.6 The construction and operation of the P/V breaker may be seen in Figure 2.5 above. The pressure setting in the P/V breaker is achieved by way of the internal water column with an equivalent pressure setting of approximately 2,000 mmWG. The water column also isolates the vapour phase from external air ingress into the system. In the event of an excessive pressure surge within the tank vapour system the water column would either be displaced out of the breaker onto the deck, in the event of excessive pressure, or drawn into the cargo tanks in the event of an under pressure. This will, therefore, open the total vapour system to the external environment and atmospheric pressure and, due to the equipment's dimensions, will relieve the pressure in the system very quickly. Thus, this safety mechanism, due to its pressure setting, will only operate if the vessel tank's P/V valves fail to operate or are not of sufficient capacity to relieve the pressure surge adequately.

[3] Reference – G.S. Marton, Tanker Operations – a Handbook for Ship's Officers, page 76.

2.4.7 It should, however, be noted that once the P/V breaker operates then, as stated above, it will reduce the pressure within the tank vapour system to atmospheric pressure, thereby exposing the tank system to ingress of oxygen. Therefore, this system is a "last resort" system to preserve the structure of the tanker from damage.

Section 3 – VOC generation systems in Crude Oil

3.1 Why limit VOC Emissions to the atmosphere? VOCs are a pollutant to the air and act as a precursor to the formation of Tropospheric Ozone – commonly termed Smog.

Thus, to control this emission, there are four criteria that impact on the extent and rate of evolution of gaseous VOC from crude oils and its subsequent release to atmosphere. These are:

.1 the volatility or vapour pressure of the crude oil;

.2 the temperature of the liquid and gas phases of the crude oil tank;

.3 the pressure setting or control of the vapour phase within the cargo tank; and

.4 the size or volume of the vapour phase within the cargo tank.

Each of these criteria are defined and briefly explained below together with any interaction between the criteria for general operational circumstances.

3.2 **The volatility or vapour pressure of the crude oil**

3.2.1 Reid Vapour Pressure (RVP) – this is an industrially developed standard test method to determine the Air Saturated absolute Vapour Pressure of volatile, non-viscous hydrocarbon liquids in compliance with the requirements specified in the Institute of Petroleum test procedure IP 69.

3.2.2 The RVP is the vapour pressure obtained within a standardized piece of test equipment for the evolved hydrocarbon vapour at a temperature of 100ºF or 37.8ºC. The standard test parameters for the determination of this pressure are important to identify and relate to the ratio of a fixed liquid volume to a fixed vapour volume. This ratio is one part liquid to four parts vapour. Thus, the pressure reported for this parameter reflects, in principle, the pressure that would be registered when the cargo tanks are about 20% loaded.

3.2.3 This leads to the importance of two other parameters, namely the Saturated Vapour Pressure and Unsaturated Vapour Pressure. These two parameters, and the physics behind them, give more clear indications and guidance with respect to a crude oil's volatility with respect to vessel operations and VOC control.

3.2.4 Saturated Vapour Pressure (SVP)[4] – is the equilibrium pressure generated by the liquid phase for the vapour volume within a defined system. The Saturated Vapour Pressure is developed only by the evolved hydrocarbon vapours from the crude oil liquid phase. For a Saturated Vapour to be present it must have contact with its own liquid phase. If the liquid phase temperature

[4] An empirical equation exists to correlate the Reid Vapour Pressure (psia) to the Saturated Vapour Pressure of a crude oil at the constant temperature of 37.8°C. This equation is: $\mathbf{P = (6.2106^{*} \ Ln \ P_R) + 4.9959}$; Where P is the Saturated Vapour Pressure (psia) at 37.8°C and P_R is the Reid Vapour Pressure (psia) at the same temperature.

increases or decreases so will the Saturated Vapour Pressure vary accordingly – an increase the liquid temperature will cause an increase in the Saturated Vapour Pressure.

3.2.5 However, if the vapour volume increases or decreases for a known liquid temperature, the pressure should, in theory, remain constant (for further understanding on this parameter see paragraph 3.5.2 below). These circumstances, respectively, will only cause the vapour to condensate and fall back to the liquid phase or more vapour to evolve from the liquid phase to maintain the Saturated Vapour Pressure. This physical characteristic is indicative of equilibrium pressure – between the liquid and vapour phases within the defined system.

3.2.6 From the foregoing it can be readily recognized that Saturated Vapour Pressure should not vary with the size of the vapour volume and will only vary with the temperature of the liquid phase – not the vapour phase temperature.

3.2.7 Unsaturated Vapour Pressure (UVP) – contrary to the concept of Saturated Vapour Pressure, an Unsaturated Vapour is not in contact with its liquid phase. In this case the vapour is obtained from other sources such as air or, more likely, Inert Gas. Thus, by reference to the standard laws of physics and what is termed the Ideal Gas Law[5], both variations in volume and/or temperature (this time it is the gas or vapour phase) will vary the pressure within a closed system.

3.2.8 From an operational perspective this type of behaviour is the primary cause of the variation of pressures within a cargo tank system over a 24-hour period and is to be associated with the Inert Gas phase within a cargo tank. However, the pressure generated from this type of gas/vapour is not the total vapour pressure in the cargo system.

3.2.9 Behind the pressure generated from the Unsaturated Vapours (Inert Gas) lies the pressure generated by the Saturated Vapours (the hydrocarbon vapours evolving from the crude oil cargo). As stated above, this pressure will remain as a constant for a given cargo/liquid temperature and, as is well recognized, a cargo temperature will not vary to the same extent as the vapour temperature due to heating or cooling from external sources (sunlight, sea temperature, air temperature, etc.). Thus, the variation for the tank observed Total Vapour Pressure is due to the presence of Inert Gas in the cargo tank.

3.2.10 Total Vapour Pressure – this pressure is the total pressure to be achieved within a defined closed system given the variable parameters of vapour volume and the differing control temperatures. In fact it is the combination or addition of the Saturated and Unsaturated Vapour Pressures (Dalton's Law of Partial Pressure[6]) within a closed and defined system.

3.2.11 Thus, on board a tanker, the pressure measured within Vapour System is the Total Vapour Pressure of the system which is the sum of the two individual pressures generated by the differing types of gases present in the system.

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[5] The Ideal Gas Law equation is **PV = nRT** or **P = (nRT)/V** where: P = Pressure, T = Temperature, V = Volume and nR are gas constants.

[6] Dalton's Law of Partial Pressure states that "The pressure of a mixture of gases is the sum of the partial pressures of its constituents".

3.3 The temperature of the crude oil in a cargo tank

3.3.1 The measurement and determination of temperature upon the two differing phases in a crude oil cargo tank have differing impacts upon the size and extent of pressure exerted at any one time in the cargo tank. In this regard it is necessary to consider the two phases separately with regard to the impact of temperature.

3.3.2 The temperature of the liquid in a crude oil cargo tank – the temperature of the liquid phase in a crude oil cargo tank will vary little over the period of a voyage unless cargo heating is being undertaken. It is this temperature that determines the Saturated Vapour Pressure that will be exerted by the evolving VOCs from the cargo volume and contribute to the Total Vapour Pressure in the cargo tank at any one time. The cooler the liquid phase temperature the lower will be the Saturated Vapour Pressure of the crude oil but care should be taken not to allow cooling of waxy cargoes too much, such that it promotes wax precipitation.

3.3.3 The temperature of the vapour or gas in a crude oil cargo tank – the temperature of the gas phase in a cargo tank will change more rapidly and vary during the day/night cycle. As this phase in the cargo tank contains a mixture of Saturated (evolved hydrocarbon gases) and Unsaturated (Inert gas) gas species the pressure in this space will vary with temperature due to the reaction of the Unsaturated Gas component to temperature (Ideal Gas Law[5]). Thus, during the day when the gas phase warms, the pressure in the tank will increase so long as there is an Inert Gas component in the gas phase. The obverse will occur at night as the gas phase cools.

3.4 The pressure setting or control of the vapour phase within the cargo tank

3.4.1 The technologies available on board crude oil tankers for the control of pressure within the cargo tank vapour system are discussed in section 2. However, it is important to identify the significance of pressure with respect to the evolution of hydrocarbon vapours from a crude oil liquid phase.

3.4.2 Control of the extent of the pressure within a crude oil cargo tank vapour system will determine the extent of further vapour evolution from a crude oil cargo. If the pressure within the system is controlled at the Saturated Vapour Pressure of the cargo, then equilibrium pressure between the liquid and vapour phase is obtained and no further VOC will evolve from the cargo. However, if the vapour pressure in the crude oil tank vapour system is reduced to a pressure below the Saturated Vapour Pressure of the cargo, then VOC will evolve to restore the equilibrium balance in the system.

3.5 The size or volume of the vapour phase within the cargo tank system

3.5.1 The size or volume of the gas or vapour phase in the cargo tank system (usually a common system on a crude oil tanker due to the interconnection through the Inert Gas pipeline system) is an important criterion to establish the pressure within the system. Again separate consideration should be given to the two differing types of gases to be found in the vapour phase and how volume may impact these component gases.

3.5.2 Saturated vapours from the crude oil liquid phase, as described above in paragraph 3.2.2, under theoretical conditions the pressure generated by saturated vapours will not be affected by a change in the volume space occupied by the vapours. However, due to the numerous species of hydrocarbon types to be found in evolved vapour from a crude oil it has been found that a volumetric change of the vapour phase from a 2% volume (V:L ratio of 0.02) to a 20% volume

(V:L ratio 0.2) will impact the saturated vapour pressure of a crude oil at a constant temperature. For vapour volumes greater than 20% of the total volume the pressure behaves similar to that expected of a Saturated Vapour; namely nearly isobaric. These circumstances can be seen in Figure 3.1 below for a selection of crude oil types.

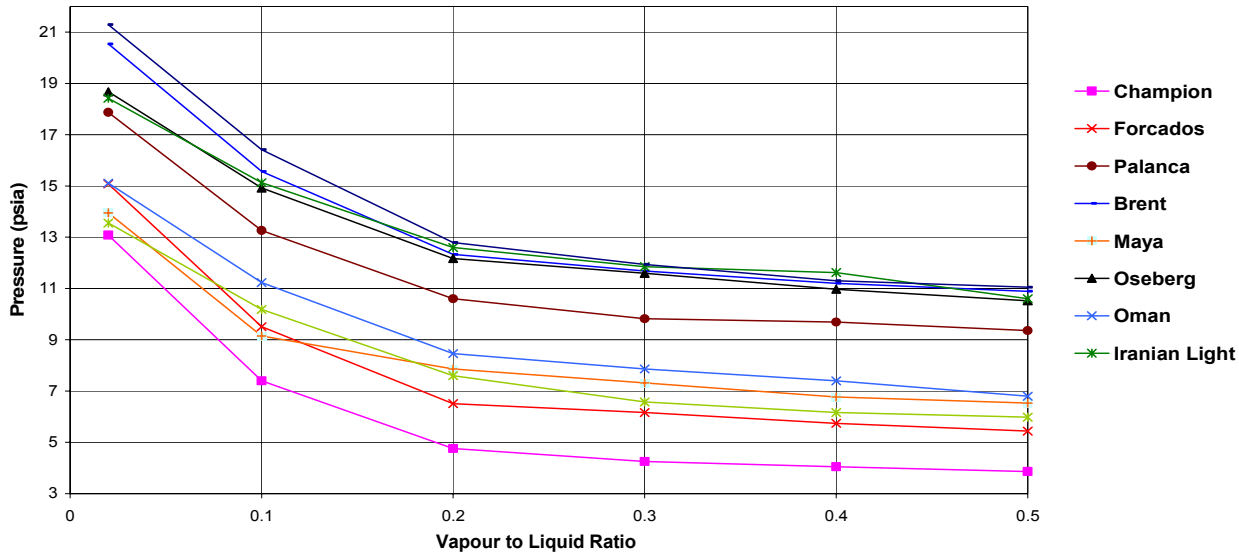


Figure 3.1

3.5.3 The change in pressure with respect to volume, for a vapour percent volume from 2% to 20%, for complexed vapour phases evolved from crude oils, is due to the influence of the individual volatile hydrocarbon types and their varying proportions in both the liquid and vapour phase that separately contribute to the final saturated vapour pressure under equilibrium conditions. The ratio of concentration of the individual hydrocarbon compounds in the vapour phase is due to the *Partition Coefficients* for each hydrocarbon type in relation to another type. This will cause a differing distribution of hydrocarbon species to that in the liquid phase when the vapour phase volume is smaller.

3.5.4 Unsaturated gases (Inert Gas) in the vapour phase system – this type of gas behaves in a manner simulated by the Ideal Gas Law equation[5]. Therefore any reduction in the volume occupied by this gas will cause an increase in the pressure exerted by the gas at a known temperature.

Section 4 – Methods and systems for the control VOC

In this section, examples of methods and systems for the control of VOC are provided.

4.1 Methods and systems for the control of VOC during Loading

4.1.1 Best Practices and design

.1 Manual pressure relief procedures (tank pressure control);

.2 P/V valve condition and maintenance;

.3 Condition of gaskets for hatches and piping;

.4 Inert gas topping up procedures;

.5 Partially filled tanks;

.6 Loading sequence and rate; and

.7 Use of vapour return manifold and pipelines when shore facilities are available.

4.1.2 **Vapour Emission Control Systems**

The principle behind VECS is that VOC generated in cargo tanks during loading is returned to the shore terminal for processing, as opposed to being emitted to atmosphere through the mast riser.

Vapour Emission Control Systems (VECS) were introduced in 1990 as a requirement for tankers loading oil and noxious liquid substances at terminals in the United States (USCG 46 CFR Part 39). IMO followed up with the introduction of IMO MSC/Circ.585 "Standards for vapour emission control systems" in 1992. International regulation requiring vapour emission control was introduced through regulation 15 of MARPOL Annex VI adopted in 1997, although it is only required for ships loading cargo at terminals where IMO has been informed that VECS is mandatory.

Since 1990, most crude tankers have installed a VECS system in compliance with USCG regulations. The regulations cover both the technical installation (vapour recovery piping and manifold, vapour pressure sensors and alarms, level gauging, high level and independent overflow alarms) as well as operational restrictions and training. The operational restrictions are found in a mandatory VECS manual which also includes maximum allowable loading rates. The maximum allowable loading rate is limited by one of the following:

.1 the pressure drop in the VECS system from cargo tank to vapour manifold (not to exceed 80% of the P/V valve setting);

.2 the maximum pressure relief flow capacity of the P/V valve for each cargo tank;

.3 the maximum vacuum relief flow capacity of the P/V valve for each cargo tank (assuming loading stopped while terminal vacuum fans are still running); and

.4 the time between activation of overfill alarm to relevant cargo tank being full (min. 1 minute).

The calculations are to be based on maximum cargo vapour/air densities as well as maximum cargo vapour growth rates, which again may limit the cargoes that can be loaded with VECS.

Further, the calculations are to be carried out both for single tank and multiple tank loading scenarios.

The USCG regulations also contain additional requirements to vapour balancing, i.e. for tankers involved in lightering operations. These include operational requirements as well as technical requirements for an in-line detonation arrestor, oxygen sensors with alarms and possibly means to prevent hazards from electrostatic charges.

For ships provided with a VECS system as per IMO or USCG regulations, the control of VOC emissions will be through returning VOC to the shore terminal in accordance with the procedures found in the onboard VECS manual.

The maximum allowable loading rates and corresponding maximum vapour/air densities and vapour growth rates should be specified in the VOC management plan.

4.1.3 Vapour Pressure Release Control Valve (VOCON valve)

The VOCON valve operates as a hydraulically controlled valve that controls the closing pressure for the valve and therefore undertakes a similar procedure to the manual VOCON procedure as described in 4.2.2 below. However, for the loading programme, the valve also allows a higher pressure to be maintained throughout the loading process in order to limit the extent of vapour evolution from the crude oil once saturated vapour pressure is achieved within the tank vapour system. This valve is normally a single valve facility and located at the bottom of the mast riser by way of a by-pass pipeline to the mast riser control valve. The relevant closing pressure setting for the valve may be done locally or remotely in the Cargo Control Room depending upon the sophistication of the installed system.

Figure 4.1 – Hydraulically controlled VOCON valve

Similar valves with fixed pressure arrangements are to be found and are currently installed on tankers and located at the same position; namely at the bottom of the mast riser by way of a by-pass pipeline to the mast riser control valve. These valves operate as a form of "tank breather" valve but release vapour through the mast riser.

4.1.4 Cargo Pipeline Partial Pressure control system (KVOC)

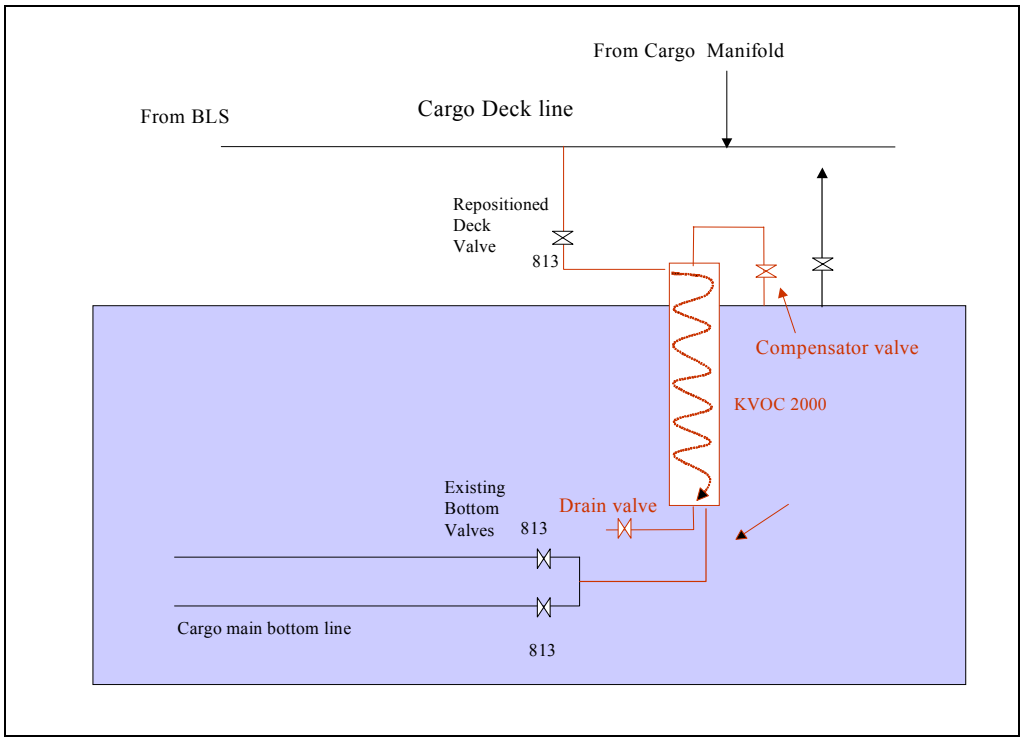
The purpose of the KVOC system installation is to minimize VOC release to the atmosphere by preventing the generation of VOC during loading and transit. The basic principle of KVOC is to install a new drop pipeline column specially designed for each tanker with respect to expected loading rate. The new drop pipeline column will normally have an increased

diameter compared to an ordinary drop line. The increased diameter will reduce the velocity of the oil inside the column and by that means ensure that the pressure adjusts itself to approximately the boiling point of the oil independent of the loading rate. In the initial phase of the loading process some VOC might be generated. The pressure inside the column will adjust itself to the SVP of the oil so that there is a balance between the pressure inside the column and the oil SVP. When this pressure has been obtained in the column the oil will be loaded without any additional VOC generation. This means that KVOC column prevents under pressure to occur in the loading system during loading.

The KVOC system is not designed to remove all VOC, but to minimize generation of VOC. VOC remaining in the tanks from the last cargo and COW operations has to be displaced from the cargo tanks when loading. Also, if the oil boiling point (SVP) is higher than the tank pressure, some crude oil will generate VOC in the tanks and additional VOC be released. Bad weather together with very volatile oil will also increase the VOC emissions due to its SVP also when KVOC is applied.

The KVOC column has an effect on the VOC release during transit, because gas bubbles have been prevented from forming. This means that the amount of gas bubbles in the oil available for release during transit will be minimized. To further reduce the release of VOC, the pressure in the cargo tanks should be held as high as possible. A high pressure, from about 800 to 1,000 mmWG, will reduce possible boiling and diffusion of VOC in the crude oil cargo tanks.

KVOC has also shown a similar effect on H_2S as on minimizing VOC generation. If the KVOC system has been installed, it should therefore always be used when loading sour crude to minimize H_2S concentration in the void spaces and release during loading and transit.



Pipeline Flow Plan for KVOC

4.1.5 **Increased pressure relief settings** ***(Applicable also for transit conditions)***

As described in sections 2 and 3, as long as the tank pressure is maintained above the Saturated Vapour Pressure of the cargo, then equilibrium is obtained between the liquid and vapour phase of the cargo and no further VOC will evolve from the cargo. This means that if the pressure/vacuum relief settings are increased to, e.g., 2,100 mmWG, VOC will not evolve from a cargo as long as the Saturated Vapour Pressure of said cargo is below the pressure relief setting.

As indicated earlier, the maximum design pressure of a cargo tank is at least 2,500 mmWG and, as such, increasing the settings of the pressure/vacuum devices up to, e.g., 2,100 mmWG, should not require additional strengthening. It will however require adjustment/replacement of P/V valves. Note that for some P/V valves designs, the pressure after initial opening increases, and this has to be taken into account if an owner intends to increase the setting of P/V valves.

Needless to say it will also require replacement/modifications to the P/V breaker, as well as water loops serving the inert gas deck water seal, as well as settings of pressure sensors and alarms in the inert gas and VECS system. It is of course also essential that onboard operational procedures in terms of manual pressure release have to be adjusted.

One additional benefit is that increasing the pressure/vacuum relief settings will increase the acceptable loading rate during VECS.

Although the primary benefit of increasing set pressure will occur during voyage. It will also have an effect related to loading, as the increased set pressure will limit the existing vapour in the cargo tanks, i.e. the vapour generated during the previous discharge and Crude Oil Washing.

For ships that have been provided with increased pressure relief settings, the VOC emissions will be controlled when the saturated vapour pressure of the crude oil is below that of the pressure relief valve settings.

It is important that terminals and cargo surveyors acknowledge that if ships with higher pressure settings are required to de-pressurize prior to cargo handling operations, this will limit the ships' ability to control VOC emissions.

4.1.6 **Vapour recovery systems – General**

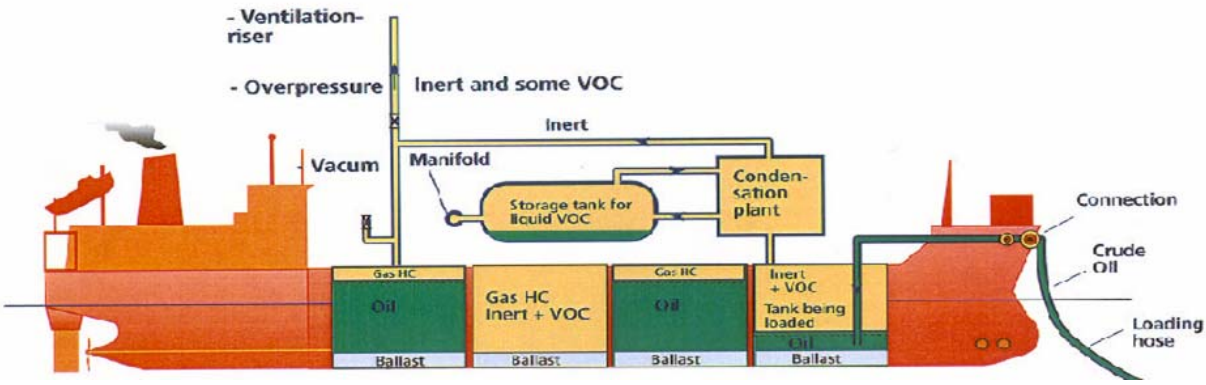
In the late 1990s certain Administrations required offshore installations to reduce their emissions of VOC and this led to the development and installation of vapour recovery systems on board shuttle tankers in the North Sea. Different concepts were developed for the purpose of reducing the emissions of VOC (VOC). The initial efficiency requirement was set to 78% (i.e. 78% less VOC emissions when using vapour recovery systems). The systems can recover VOC in all operational phases.

For ships that have been provided with vapour recovery systems, the VOC emissions will be controlled when the recovery plant is in operation.

The VOC recovery plant efficiency as well as any operational limitations related to, e.g., applicability for different cargo handling modes (loading, transit, COW), maximum allowable loading rates or crude vapour pressures, are to be specified in the VOC management plan.

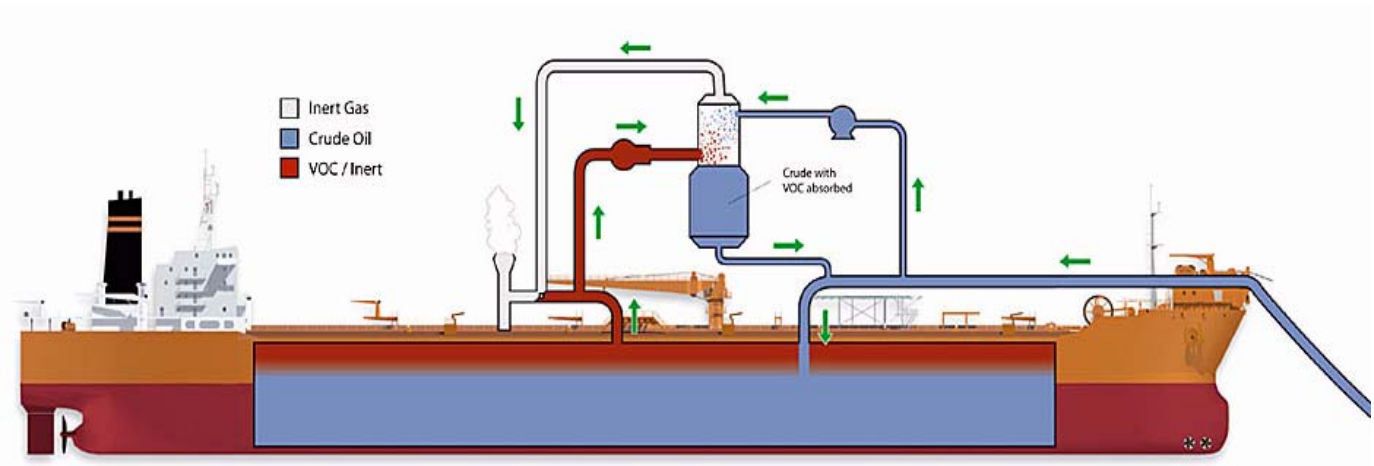
4.1.6.1 **Vapour Recovery Systems – Condensation Systems**

The principle is similar to that of re-liquefaction plants on LPG carriers, i.e. condensation of VOC emitted from cargo tanks. In the process, the VOC passes through a knock out drum before it is pressurized and liquefied in a two stage process. The resulting liquefied gas is stored in a deck tank under pressure and could either be discharged to shore, or be used as fuel (possibly including methane and ethane) for boilers or engines subject to strict safety requirements. It is also conceivable that the stored gas could be used as an alternative to inert gas subject to the Administration's acceptance.



4.1.6.2 **Vapour Recovery Systems – Absorption Systems**

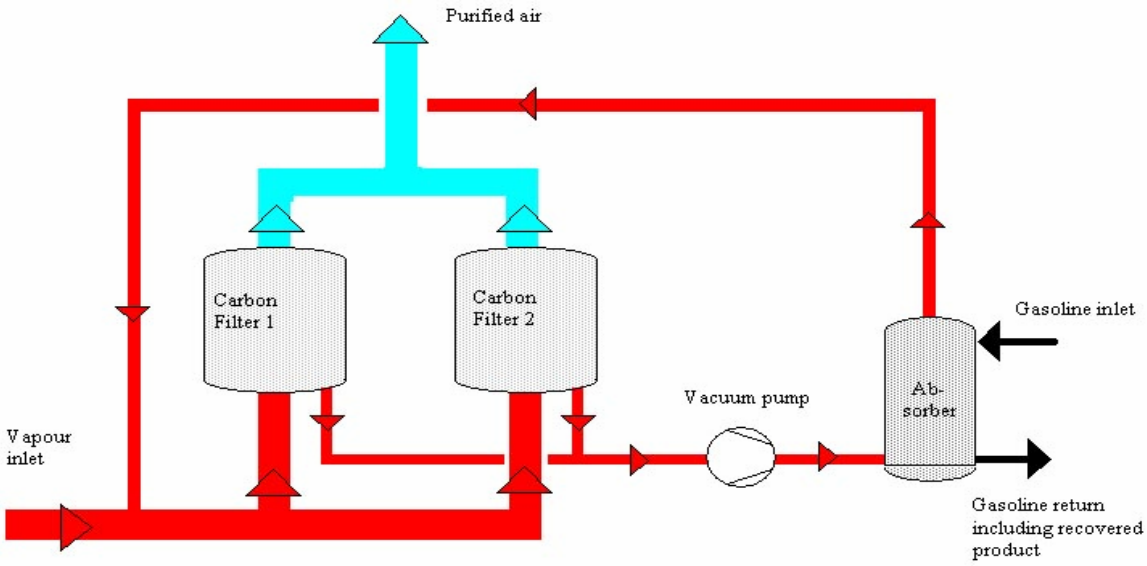
The technology is based on the absorption of VOCs in a counter-current flow of crude oil in an absorber column. The vapour is fed into the bottom of the column, with the side stream of crude oil acting as the absorption medium. The oil containing the absorbed VOC is then routed from the bottom of the column back to the loading line where it is mixed with the main crude oil loading stream. Oil pumps and compressors are used to pressurize the oil and gas. Unabsorbed gases are relieved to the riser to increase the recovery efficiency. Similar concepts have been developed using swirl absorbers instead of an absorption column.



4.1.6.3 **Vapour Recovery Systems – Absorption Carbon Vacuum-Regenerated Adsorption**

In the CVA process, the crude oil vapours are filtered through active carbon, which adsorbs the hydrocarbons. Then the carbon is regenerated in order to restore its adsorbing capacity and adsorb hydrocarbons in the next cycle. The pressure in the carbon bed is lowered by a vacuum pump until it reaches the level where the hydrocarbons are desorbed from the carbon. The extracted, very highly concentrated vapours then pass into the absorber, where the gas is absorbed in a stream of crude oil taken from and returned to the cargo tanks.

As carbon bed adsorption systems are normally sensitive to high concentrations of hydrocarbons in the VOC inlet stream, the VOC feed stream first passes through an inlet absorber where some hydrocarbons are removed by absorption. The recovered VOC stream may be reabsorbed in the originating crude oil in the same inlet absorber.



4.2 Methods and systems for the control of VOC during Transit

4.2.1 Best Practices/Design

.1 Manual pressure relief procedures (tank pressure control);

.2 P/V valve condition and maintenance;

.3 Condition of gaskets for hatches and piping;

.4 Inert gas topping up procedures;

.5 Partially filled tanks;

.6 Loading sequence and rate; and

.7 COW procedures (closed cycle[7]).

4.2.2 VOCON procedure

By reference to Figure 4.2 below, this procedure requires the monitoring and the recording of the pressure drop during a release of gas from the cargo tank vapour system. This can be undertaken with the use of the Inert Gas pressure gauge in the cargo control room or, as available, located on the Inert Gas pipeline on deck. Figure 4.2 shows a pressure drop profile using the mast riser and the inflection in the pressure drop where the mast riser valve should be shut.

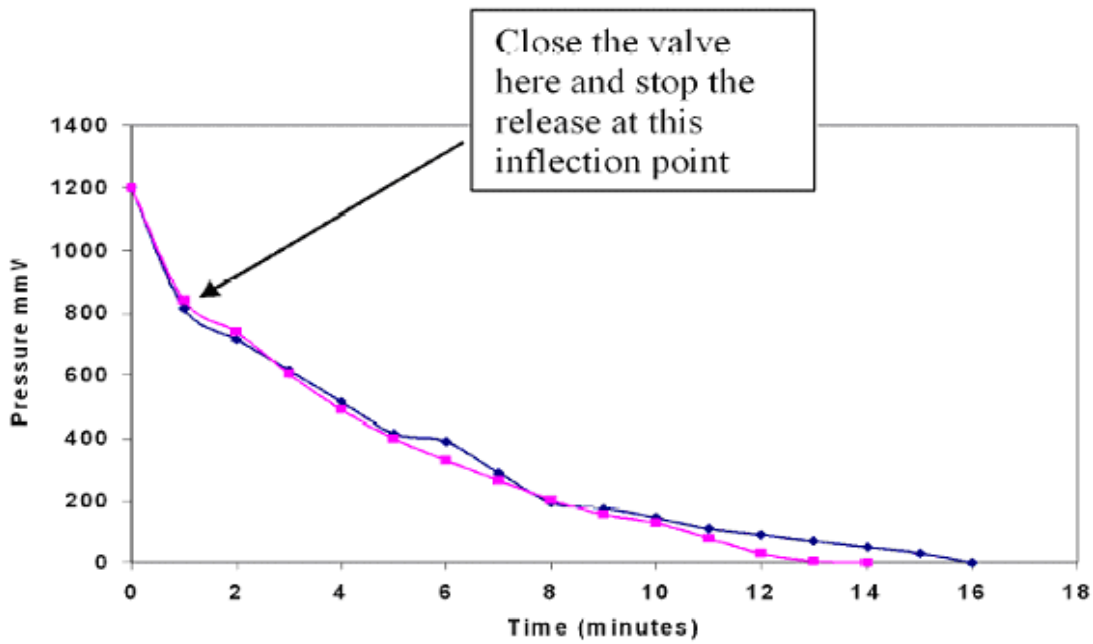


Figure 4.2 – A mast riser release

[7] "Closed Cycle" crude oil washing means that the tanker's slop tank is used as the reservoir for the crude oil wash stock and this wash stock is stripped or cycled back to the slop tank for reuse. Thus, using a defined volume of crude oil for washing of the specified cargo tanks will limit the amount of VOC associated with the wash stock volume as distinct from using fresh crude oil throughout the washing programme.

The VOCON operational procedure

(1) Before opening the mast riser, note the pressure in the Inert Gas pipeline system.

(2) Open the pressure release valve and record/monitor the pressure within the Inert Gas pipeline at regular short intervals (every 30 seconds for a mast riser release).

(3) Plot the pressure drop profile. This can be achieved either manually or by use of the Inert Gas Oxygen and Pressure Recorder in the Cargo Control Room but an increase in the Recorder paper feed rate will be required to achieve definition of the plot.

(4) When the rate of pressure drop becomes constant (after the initial rapid pressure drop) then the gas release should be stopped and the valve closed.

(5) Monitor the Tank Gas Pressure after completion of the controlled release in order to check the final pressure obtained within the Vapour/Inert Gas system.

Advice Notes

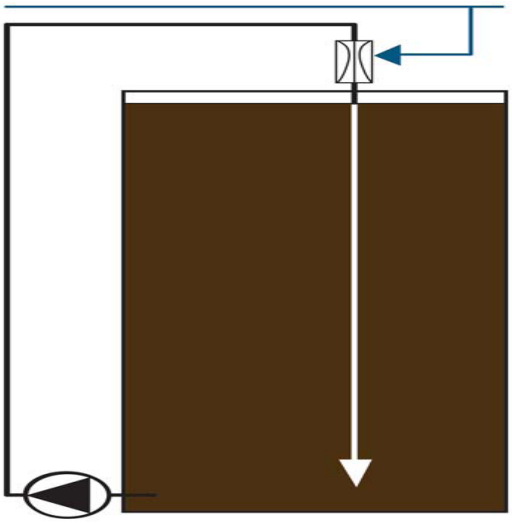
(A) A review of Figure 4.2 shows a clear change in the rate of pressure drop during the release period. If the gas release continues after this point then the pressure in the Inert Gas system will be quickly restored to the pressure associated with the point where the rate of pressure drop changes.

(B) If there is a straight line drop of pressure observed and no inflection observed by 800 mmWG, then close the release valve anyway.

(C) By reference to the ISGOTT Publication, all safety measures should be taken to minimize the hazards associated with vented gases from the vessel's cargo tank system.

4.2.3 **Recovery of excess VOC and tank absorption (Venturi system)**

The Venturi system involves a process where evolved VOC is reabsorbed back into the cargo. The system typically consists of a pressure controlled pump, feeding oil to a unit with Venturi(s). The Venturi draws VOC, H_2S and inert gases (IG) from the common cargo tank venting/inert gas main line. The Venturi unit is designed to generate a bubble size optimal for their collapse in the crude oil cargo and rapid absorption. Released near the tank bottom, the soluble compounds are kept dissolved by the pressure head there. Inert gas will eventually surface.



Oil is pumped from a cargo tank through the Venturi unit. Gas is sucked in from the main inert gas line and injected at the bottom of the tank.

For ships that have been provided with a Venturi type system, the VOC emissions will be controlled when the system is in operation.

The VOC control system efficiency as well as any operational limitations related to, e.g., applicability for different cargo handling modes (loading, transit, COW), maximum allowable loading rates or crude vapour pressures, are to be specified in the VOC management plan.

4.3 **Methods and systems for the control of VOC during Discharging/Ballasting**

Emissions of VOC during ballasting had relevance when tankers took ballast into cargo tanks for stability and longitudinal strength reasons and thus displaced VOC from cargo tanks being ballasted. After the implementation of requirements to segregated ballast tanks and, of course, double hull, VOC releases during discharge and ballasting are no longer an issue.

During discharging of cargo tanks, it is important that pressure monitoring is exercised in order to avoid excessive supply of inert gas to cargo tanks.

Section 5 – The Monitoring and Control of VOC Releases

5.1 Record keeping is necessary in order to document compliance with the requirements of the management plan and, potentially, the extent of release of gases from the crude oil cargo tanks. The form of record keeping is dependent upon the specific form of method used to minimize the emission of VOC from the crude oil cargo. It will also be dependent upon the operation being performed by the ship necessitating the release of VOC, namely loading during the carriage or as a result of a crude oil washing (COW) operation.

5.2 As a general example of the type and scope of record keeping to be undertaken on board the crude oil tanker, the methodology of the manual VOCON procedure is used. The appropriate record keeping is as follows:

.1 The target or minimum pressure within the tank gas/vapour system for the specific voyage

.1.1 A record of the time and pressure within the tank gas/vapour system before the release takes place.

.1.2 A record of the time and pressure within the gas/vapour system after the release has been completed.

5.3 The foregoing data and information may be compiled by the ship's management company or operators in order to assess or quantify the extent or degree of VOC release. As an outline to such assessment the following can be taken into consideration:

.1 For those ships operating with manual VOC control by the VOCON procedure, the released volume of gas/vapour can be estimated by use of the pressure change (opening to closing pressures) relationship to the total gas/vapour volume in the cargo tank vapour system (Ideal Gas Laws – reference to section 3).

Section 6 – Training Programme

6.1 A training programme is to be developed for the persons intended to assume overall charge of the VOC management on board each ship. The programme is to include the following:

.1 An introduction to the purpose of VOC emission control:

.1.1 Volatile organic compounds (VOCs) may be toxic, and when they evaporate into the air they can react with Nitrogen Oxides (NO_x) in sunlight and split apart oxygen molecules in air and thereby form ground-level ozone, commonly referred to as smog. The layer of brown haze it produces is not just an eyesore, but also is a source of serious illnesses. Ozone is extremely irritating to the airways and the lungs, causing serious damage to the delicate cells lining the airways. It contributes to decreased lung function, increased respiratory symptoms and illnesses.

.1.2 Regulation 15 of MARPOL Annex VI

.2 An introduction to the principles of VOC emission control:

.2.1 VOC generation systems in crude oil (ref. section 3)

.2.2 Crude oil tanker pressure control/release systems (ref. section 2)

.3 General VOC emission control options:

.3.1 Methods and systems for the control of VOC emissions (ref. section 4)

.4 Ship specific VOC emission control options:

.4.1 Ship specific methods and systems for the control of VOC emissions (ref. section 4)

.5 Monitoring and recording of VOC release:

.5.1 Methods for monitoring and recording of VOC emissions (ref. section 5)

.6 Hazards and Safety related to VOC emission control:

.6.1 The hull and its pressure limitations (ref. section 1)

.6.2 Personnel safety hazards related to exposure to crude oil vapour.

Section 7 – Designated Person

7.1 A person should be designated to assume overall charge of the VOC management on board the ship.

The designated person should preferably have:

.1 At least one year's experience on crude oil tankers where his or her duties have included all cargo handling operations relevant to VOC management. In the absence of experience with VOC management, he or she should have completed a training programme in VOC management as specified in the VOC management plan;

.2 participated at least twice in cargo loading operations, Crude Oil Washing Operations and transit where VOC management procedures have been applied, one of which should be on the particular ship or a similar ship in all relevant aspects, for which he or she is to undertake the responsibility of VOC management; and

.3 full knowledge of the contents of the VOC management plan.

Section 8 – List of drawings

8.1 The following drawings are recommended included as appendices to the management plan:

.1 General Arrangement drawing;

.2 Tank plan;

.3 Schematic drawing(s) of the Cargo tank venting system;

.4 Schematic drawing of the inert gas system;

.5 Schematic drawing of the vapour emission control systems (if applicable);

.6 Schematic drawing(s) Vapour Recovery System or other VOC control systems; and

.7 Details of pressure vacuum relief devices including settings and capacities.

References:

.1 Vapour Emission Control System manual (if applicable);

.2 Vapour Recovery System manual (if applicable);

.3 Other VOC control system manual (if applicable);

.4 Inert Gas manual; and

.5 COW manual.

ATTACHMENT 3 – DETAILED EMISSION CALCULATIONS

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Marine Loading (DWP Emissions Source for PSD Applicability)
Criteria Pollutants

Hourly and Annual VOC Emissions Estimates for Loading of Crude Oil and Condensate

Hourly Loading Emissions

Liquid Loaded [1]	Saturation Factor [2]	Maximum Temp [3] (˚F)	Maximum Temp [3] (˚R)	Vapor MW (lb/lb mol)	Maximum True Vapor Pressure (TVP) [4] (psia)	Arrival Emission Factor [5] (lb/1,000 gal)	Generated Emission Factor [6] (lb/1,000 gal)	Uncontrolled Loading Loss [7] (lb/1,000 gal)	TOC to VOC Factor	Hourly Loading Rate [8] (bbl/hr)	Uncontrolled VOC Hourly Emissions [9] (lb/hr)
Crude Oil	0.2	73.50	533.17	50	11.00	--	--	2.57	1.00	60,000	6,478.07
Condensate	0.2	73.50	533.17	60	11.00	--	--	3.08	1.00	60,000	7,773.68

[1] For hourly emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.

[2] Saturation factor for marine loading obtained from U.S. EPA 42, Section 5.2 (1/95), Table 5.2-1.

[3] Maximum of monthly average liquid surface temperature was used .

[4] Maximum true vapor pressure for Crude oil and Condensate obtained from information provided by Texas Gulf Terminals

[5] Arrival emission factor for crude/condensate loading obtained from U.S. EPA 42, Section 5.2 (1/95), Table 5.2-3.

[6] Generated emission factor is calculated using equation 3 from U.S. EPA 42, Section 5.2 (1/95).

[7] Uncontrolled Loading Loss (lb/1,000 gal) = 12.46 x Saturation Factor x Maximum TVP of Liquid Loaded (psia) x Vapor MW (lb/lbmol) / Maximum Temperature of Bulk Liquid Loaded (^{o}R)

$$\text{Crude Oil Uncontrolled Loading Loss (lb/1,000 gal)} = \frac{12.46 \;\vert\; 0.2 \;\vert\; 11.00\text{ psia} \;\vert\; 50\text{ lb}}{\text{lbmole}} \;\vert\; \frac{1}{533.17\text{ R}} = 2.57\text{ lb/1,000 gal}$$

[8] Hourly Loading Rate obtained from information provided by TGTI Revised Design Parameters email from Ms. Denise Rogers (TGTI) to Mr. Brian Burdorf (Trinity Consultants) on February 25, 2018.

[9] Uncontrolled VOC Hourly Emissions (lb/hr) = Uncontrolled Loading Loss (lb/1,000 gal) x Hourly Loading Rate (bbl/hr) x 42 gal/bbl x TOC to VOC Factor x (1/1,000)

$$\text{Crude Oil Uncontrolled Loading Emissions (lb/hr)} = \frac{2.57\text{ lb}}{1{,}000\text{ gal}} \;\vert\; \frac{60{,}000\text{ bbl}}{\text{hr}} \;\vert\; \frac{42\text{ gal}}{\text{bbl}} \;\vert\; 1.00 \;\vert\; \frac{1}{1{,}000} = 6{,}478\text{ lb/hr}$$

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Marine Loading (DWP Emissions Source for PSD Applicability)
Criteria Pollutants

Annual Loading Emissions

Liquid Loaded [1]	Saturation Factor [2]	Annual Average Temp [3] (˚F)	Annual Average Temp [3] (˚R)	Vapor MW (lb/lb mol)	Average True Vapor Pressure (TVP) [4] (psia)	Arrival Emission Factor [5] (lb/1,000 gal)	Generated Emission Factor [6] (lb/1,000 gal)	Uncontrolled Loading Loss [7] (lb/1,000 gal)	TOC to VOC Factor	Annual Loading Rate [8] (bbl/yr)	Uncontrolled VOC Annual Emissions [9] (tpy)
Crude Oil	0.2	73.50	533.17	50	11.00	--	--	2.57	1.00	192,000,000	10,364.91
Condensate	0.2	73.50	533.17	62	9.25	--	--	2.68	1.00	192,000,000	10,807.77

[1] For annual emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.

[2] Saturation factor for marine loading obtained from U.S. EPA 42, Section 5.2 (1/95), Table 5.2-1.

[3] Average of monthly average liquid surface temperature was used .

[4] Average true vapor pressure for Crude oil and Condensate obtained from information provided by Texas Gulf Terminals

[5] Arrival emission factor for crude/condensate loading obtained from U.S. EPA 42, Section 5.2 (1/95), Table 5.2-3.

[6] Generated emission factor is calculated using equation 3 from U.S. EPA 42, Section 5.2 (1/95).

[7] Uncontrolled Loading Loss (lb/1,000 gal) = 12.46 x Saturation Factor x Average TVP of Liquid Loaded (psia) x Vapor MW (lb/lbmol) / Average Temperature of Bulk Liquid Loaded (^{o}R)

$$\text{Crude Oil Uncontrolled Loading Loss (lb/1,000 gal)} = \frac{12.46 \quad 0.2 \quad 11.00\text{ psia} \quad 50\text{ lb} \quad 1}{\quad\quad\quad\quad\quad\quad\quad\quad \text{lbmole} \quad 533.17\text{ R}} = 2.57\text{ lb/1,000 gal}$$

[8] Annual Loading Rate obtained from information provided by TGTI Revised Design Parameters email from Ms. Denise Rogers (TGTI) to Mr. Brian Burdorf (Trinity Consultants) on February 25, 2018 and June 22, 2018.

[9] Uncontrolled VOC Loading Emissions (tpy) = Uncontrolled Loading Loss (lb/1,000 gal) x Annual Loading Rate (bbl/yr) x 42 gal/bbl x TOC to VOC Factor x (1/1,000) x (1 ton/2,000 lb)

$$\text{Crude Oil Uncontrolled Loading Emissions (tpy)} = \frac{2.57\text{ lb} \quad 192{,}000{,}000\text{ bbl} \quad 42\text{ gal} \quad 1.00 \quad 1 \quad 1\text{ ton}}{1{,}000\text{ gal} \quad \text{yr} \quad \text{bbl} \quad\quad 1{,}000 \quad 2{,}000\text{ lb}} = 10{,}365\text{ tpy}$$

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Marine Loading (DWP Emissions Source for PSD Applicability)
Criteria Pollutants

Hourly and Annual H_2S Emissions Estimates for Loading of Crude Oil and Condensate

Parameter	Value	Unit
H_2S MW	34.1	lb/lbmol
H_2S Max Vapor Fraction in Crude oil [1]	2.40E-05	
H_2S Max Vapor Fraction in Condensate [1]	2.40E-05	
Maximum Mass Ratio of H_2S in Crude Oil [2]	2.19E-05	lb H_2S/lb VOC
Maximum Mass Ratio of H_2S in Condensate [2]	1.76E-05	lb H_2S/lb VOC

[1] Maximum H_2S vapor fraction is assumed to be 24 ppmv for sweet crude.
[2] H_2S Mass Ratio in Crude Oil/Condensate (lb H_2S/lb VOC) = H_2S Vapor Fraction in Crude Oil/Condensate x H_2S MW (lb/lbmole)/Crude Oil/Condensate Vapor MW (lb/lbmole) x 14.7 psia/Vapor Pressure of Crude Oil/Condensate (psia)

$$\text{Max } H_2S \text{ Mass Ratio in Crude Oil (lb } H_2S\text{/lb VOC)} = \frac{2.40\text{E-05}}{} \cdot \frac{34.1 \text{ lb}}{\text{lbmole}} \cdot \frac{\text{lbmole}}{50 \text{ lb}} \cdot \frac{14.7 \text{ psia}}{11 \text{ psia}} = 2.19\text{E-05 lb H2S/lb VOC}$$

Liquid Loaded [1]	Maximum TVP [2] (psia)	Uncontrolled VOC Hourly Emissions (lb/hr)	Uncontrolled VOC Annual Emissions (tpy)	H_2S Hourly Emissions [3] (lb/hr)	H_2S Annual Emissions [4] (tpy)
Crude Oil	11.00	6,478	10,365	0.14	0.23
Condensate	11.00	7,774	10,808	0.17	0.24

[1] For hourly and annual emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.
[2] Maximum true vapor pressure for Crude oil and Condensate obtained from information provided by Texas Gulf Terminals
[3] H_2S Hourly Emissions (lb/hr) = Max H_2S Mass Ratio in Crude/Condensate (lb H_2S/lb VOC) x Uncontrolled VOC Hourly Emissions (lb/hr)

$$H_2S \text{ Hourly Emissions from Crude Oil (lb/hr)} = \frac{2.19\text{E-05 lb H2S}}{\text{lb VOC}} \cdot \frac{7{,}774 \text{ lb}}{\text{hr}} = 0.14 \text{ lb/hr}$$

[4] H_2S Annual Emissions (tpy) = Max H_2S Mass Ratio in Crude/Condensate (lb H_2S/lb VOC) x Uncontrolled VOC Annual Emissions (tpy)

$$H_2S \text{ Annual Emissions from Crude Oil (tpy)} = \frac{2.19\text{E-05 lb H2S}}{\text{lb VOC}} \cdot \frac{10{,}808 \text{ tpy}}{} = 0.23 \text{ tpy}$$

Texas Gulf Terminals Inc.
Normal Operations Emission Calculations
Marine Loading (DWP Emissions Source for PSD Applicability)
Hazardous Air Pollutants

Parameter	Value	Unit
Max. benzene vapor weight % in Crude Oil [1]	0.95%	
Max. benzene vapor weight % in Condensate [1]	0.43%	
Max toluene Vapor weight % in Crude Oil [1]	0.98%	
Max toluene Vapor weight % in Condensate [1]	0.37%	

[1] Benzene and toluene vapor weight fraction is based on Tanks 4.09D run.

Pollutant	Liquid Loaded [1]	Uncontrolled VOC Hourly Emissions (lb/hr)	Uncontrolled VOC Annual Emissions (tpy)	Maximum Emissions [2] (lb/hr)	Annual Emissions [3] (tpy)
Benzene	Crude Oil	6,478	10,365	61.54	98.47
	Condensate	7,774	10,808	33.43	46.47
Toluene	Crude Oil	6,478	10,365	63.49	101.58
	Condensate	7,774	10,808	28.76	39.99

[1] For hourly and annual emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.
[2] Benzene Hourly Emissions (lb/hr) = Max Benzene % in Crude/Condensate Vapors x Uncontrolled VOC Hourly Emissions (lb/hr)
[3] Emissions are based on the total VOC emissions for Loading of Crude Oil and Condensate calculated in the previous table.

$$\text{Benzene Hourly Emissions from Crude Oil (lb/hr)} = \frac{0.95\% \quad 6{,}478\ \text{lb}}{\text{hr}} = 61.54\ \text{lb/hr}$$

Toluene Hourly Emissions (lb/hr) = Max Toluene % in Crude/Condensate Vapors x Uncontrolled VOC Hourly Emissions (lb/hr)

$$\text{Toluene Hourly Emissions from Crude Oil (lb/hr)} = \frac{0.98\% \quad 6{,}478\ \text{lb}}{\text{hr}} = 63.49\ \text{lb/hr}$$

[3] Benzene Annual Emissions (tpy) = Max Benzene % in Crude/Condensate Vapors x Uncontrolled VOC Annual Emissions (tpy)

$$\text{Benzene Annual Emissions from Crude Oil (tpy)} = \frac{0.95\% \quad 10{,}365\ \text{tons}}{\text{yr}} = 98.47\ \text{tpy}$$

Toluene Annual Emissions (tpy) = Max Toluene % in Crude/Condensate Vapors x Uncontrolled VOC Annual Emissions (tpy)

$$\text{Toluene Annual Emissions from Crude Oil (tpy)} = \frac{0.98\% \quad 10{,}365\ \text{tons}}{\text{yr}} = 101.58\ \text{tpy}$$

Title V Permit Application

Texas Gulf Terminals Inc.
Texas Gulf Terminals Project

Appendix E

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July 2018

Trinity Consultants

Environmental solutions delivered uncommonly well

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1.1. PROJECT BACKGROUND

Texas Gulf Terminals Inc. (TGTI) is proposing to construct, own, and operate a Deepwater Port (DWP) terminal, as part of the Texas Gulf Terminal Project, in Federal waters of the U.S. Gulf of Mexico located approximately 14 miles off the coast of North Padre Island in Kleberg County, Texas.

Hereinafter, the Texas Gulf Terminal Project will be referred to as "the project" or "the proposed project." The purpose of the proposed project is to provide a logistical solution for the safe and reliable export of crude oil from the United States to free trade and non-free trade nations to support U.S. economic growth. The proposed project would fulfill the need for a safe, efficient, and cost-effective outlet for abundant supplies of domestic crude oil from existing and future oil fields located in the United States. The DWP terminal will include a Single Point Mooring (SPM) Buoy to moor a Very Large Crude Carrier (VLCC). The size of these VLCCs prevent them from using the docks at the onshore terminals. Therefore, VLCCs have to be engaged offshore. The project will serve as a crude oil export facility with a capacity of 60,000 barrels per hour (bph) and 192 million barrels per year. The project will be able to load up to 96 VLCCs per year. The proposed project is comprised of two major offshore components: the SPM Buoy system and the offshore pipelines. A detailed description of the SPM Buoy system components and the offshore pipeline system is provided in Section 5.

Per 33 CFR §148.3(d), The Environmental Protection Agency (EPA) is designated as cooperating agency to support the Coast Guard and MARAD in the review and evaluation of DWP license applications. Since the proposed project results in emissions of regulated pollutants in amounts greater than the Title V Major Source threshold of 100 tpy for criteria pollutants and 10/25 tpy of HAPs, TGTI is submitting this permit application as part of the DWP license application to MARAD/USCG. TGIT has prepared the application on Texas Commission on Environmental Quality (TCEQ) forms based on guidance received from EPA Region 6. With this submittal, TGTI is proposing to authorize the Volatile Organic Compounds (VOC) and HAP emissions resulting from the loading of crude oil from the DWP Terminal onto a VLCC. Based on potential air emissions from the facility, the project will be subject to the requirement to obtain a Title V operating permit regulations per 40 CFR Part 71 Requirements. A deepwater port is defined in 33 CFR 148.5 as follows:

> *Any fixed or floating manmade structures other than a vessel, or any group of structures, located beyond State seaward boundaries that are used or are intended for use as a port or terminal for the transportation, storage, or further handling of oil or natural gas for transportation to any State, except as otherwise provided in the Deepwater Ports Act of 1974, as amended, and for other uses not inconsistent with the purposes of the Deepwater Port Act, including transportation of oil and natural gas from the United States' OC; [...] Must be considered a 'new source' for purposes of the Clean Air Act.."*

As mentioned above, the DWP consists of the SPM buoy system that is used for loading of crude carrier vessels. Per the 1974 DWPA, the revised 2012 DWPA, and the DWP regulations (40 CFR 148.5), a DWP new source for purposes of the Clean Air Act is defined as "any fixed or floating manmade structure other than a vessel, or any group of such structures, that are located beyond State seaward boundaries and that are used or intended for use as a port or terminal for the transportation, storage, or further handling of oil or natural gas for transportation to or from any State..."[1]. Therefore, vessels are not considered primary/direct sources of emissions from the Project for Clean Air Act Title V applicability.

Supporting documentation for this application is provided in the following sections. Included in Section 2 of this permit application discusses 40 CFR Part 71 Title V regulations. The project location is discussed in Section 3, with an area map indicating the site location. Section 4 of this permit application is the required applicant

information (including 40 CFR Part 71 forms, TCEQ Form PI-1 and Table 1(a)). The process and project descriptions are provided in Section 5, including a process flow diagram. Emission calculations and summary is presented in Section 6. Applicable State and Federal requirements including BACT and case-by-case MACT are covered in Section 7. Permit fee is covered in Section 8. Lastly, certification of compliance is addressed in Section 9.

2. 40 CFR PART 71 TITLE V REGULATIONS

Per 40 CFR §71.3(a)(1) a major source of air emissions is subject to the permitting requirements under 40 CFR Part 71. Since potential emissions of VOC from the proposed SPM buoy system will exceed the Title V major source threshold of 100 tpy, the proposed SPM buoy system is subject to federal operating permit requirements contained in 40 CFR Part 71. TGTI is therefore obligated to submit a timely and complete application in accordance with 40 CFR §71.5.

According to this section, a timely application for a source that does not have an existing operating permit issued by a State under the State's approved part 70 program and is applying for a part 71 permit for the first time is one that is submitted within 12 months after the source becomes subject to the permit program (i.e., 12 months after commencing operation). However, because issuance of this permit is outside the scope of MARAD and USCG control, and may occur after a MARAD license is issued, TGTI is submitting this initial Title V application in advance of the regulatory due date of 12 months after commencing operation that is identified in 40 CFR §71 to allow for consistency of review within the National Environmental Protection Act (NEPA) process.

A complete application is defined as one that contains all of the information in 40 CFR §71.5(c). At the request of EPA Region 6, the Title V permit application is being submitted using EPA's Part 71 forms which are included in this application. The forms provided by EPA for 40 CFR Part 71 and the information included in this application narrative satisfy the following requirements for deeming a complete application:

- Identifying information, including plant name and address, owner's name and agent, and telephone number and names of the plant site manager/contact;
- A description of the source's processes and products (by SIC Code) including those associated with any proposed alternative operating scenarios identified by the source;
- Emissions related information including:
  - Emissions of regulated air pollutants;
  - Identification of points of emission;
  - Emission rates in tpy;
  - Information needed to determine emissions;
  - Identification and description of pollution control equipment;
  - Limitations on source operation affecting emissions or any work practice standards, where applicable for regulated pollutants;
  - Other information required by applicable requirements; and,
  - Emissions calculations;
- Citation of the applicable requirements;
- Other information needed to implement and enforce applicable requirements of the Clean Air Act or to determine applicability of other regulations;
- An explanation of any proposed exemptions from otherwise applicable requirements;
- Additional information as deemed necessary;
- A certification of compliance; and
- List of insignificant activities and emissions levels.

With this application and the inclusion of the 40 CFR Part 71 forms in Section 4 of this application, TGTI is submitting a timely and complete Title V permit application for the proposed SPM buoy system.

3.1. PROJECT LOCATION

The proposed DWP would be positioned within territorial seas of the OCS Mustang Island Area TX3 (Gulf of Mexico), within the Bureau of Ocean Energy Management (BOEM) block number 823. The proposed DWP is positioned at Latitude N27° 28' 42.60" and Longitude W97° 00' 48.43", approximately 12.7 nautical miles (14.62 statute miles) off the coast of North Padre Island in Kleberg County, Texas. Figure 3-1 provided below shows the location of the DWP terminal.

Figure 3-1. Location of the DWP Terminal

4. APPLICANT INFORMATION

40 CFR PART 71 FORMS

CORE DATA FORM

PI-1 FORM

United States Environmental Protection Agency

OMB No. 2060-0336,
Approval Expires 05/31/2019

Federal Operating Permit Program (40 CFR Part 71)
GENERAL INFORMATION AND SUMMARY (GIS)

A. Mailing Address and Contact Information

Facility name Texas Gulf Terminals Project

Mailing address: Street or P.O. Box 1401 McKinney, Suite 1500
City Houston _____ State TX ZIP 77010

Contact person: Denise Rogers Title Regulatory Compliance Manager – North America

Telephone (832) 203 - 6493 Ext. _____

Facsimile (832) 203 - 6401

B. Facility Location

Temporary source? ___Yes _X_No Plant site location Site is approximately 14 miles offshore the coast of Texas, Southeast of Corpus Christi. Latitude N27° 28' 42.6" and Longitude W97° 00' 48.43"

City N/A State N/A County N/A EPA Region 6

Is the facility located within:

Indian lands? ___YES _X_NO An offshore source in federal waters? _X_YES ___ NO

Non-attainment area? ___ YES _X_NO If yes, for what air pollutants? _____

Within 50 miles of affected State? ___YES _X_NO If yes, What State(s)? _____

C. Owner

Name Texas Gulf Terminals Inc. Street/P.O. Box 1401 McKinney, Suite 1500

City Houston _____ State TX ZIP 77010

Telephone (832) 203 - 6400 Ext_____

D. Operator

Name Texas Gulf Terminals Inc. Street/P.O. Box 1401 McKinney, Suite 1500

City Houston _____ State TX ZIP 77010

Telephone (832) 203 - 6400 Ext_____

E. Application Type

Mark only one permit application type and answer the supplementary question appropriate for the type marked.

_X_ Initial Permit ___ Renewal ___ Significant Mod ___ Minor Permit Mod(MPM)

___ Group Processing, MPM ___ Administrative Amendment

For initial permits, when did operations commence? TBD

For permit renewal, what is the expiration date of current permit? _____/____/_____

F. Applicable Requirement Summary

Mark the types of applicable requirements that apply:

___SIP ___FIP/TIP _X_ PSD ___Non-attainment NSR

___ Minor source NSR ___ Section 111 ___ Phase I acid rain ___Phase II acid rain

___ Stratospheric ozone ___ OCS regulations ___ NESHAP ___ Sec. 112(d) MACT

_X_ Sec. 112(g) MACT ___ Early reduction of HAP ___ Sec 112(j) MACT ___ RMP [Sec.112(r)]

___ Section 129 ___ NAAQS, increments or visibility but for temporary sources (This is rare)

Is the source subject to the Deepwater Port Act? _X_ YES ___NO

Has a risk management plan been registered? ___YES _X_ NO Agency _____

Phase II acid rain application submitted? ___YES _X_ NO If YES, Permitting Authority _____

G. Source-Wide PTE Restrictions and Generic Applicable Requirements

Cite and describe any emissions-limiting requirements and/or facility-wide "generic" applicable requirements.

Please see Appendix E of application.

H. Process Description

List processes, products, and SIC codes for the facility.

Process	Products	SIC
Marine Loading Terminal	Crude / Condensate	4612

I. Emission Unit Identification

Assign an emissions unit ID and describe each emissions unit at the facility. Control equipment and/or alternative operating scenarios associated with emissions units should by listed on a separate line. Applicants may exclude from this list any insignificant emissions units or activities.

Emissions Unit ID	Description of Unit
LOADFUG	Marine Loading

J. Facility Emissions Summary

Enter potential to emit (PTE) for the facility as a whole for each regulated air pollutant listed below. Enter the name of the single HAP emitted in the greatest amount and its PTE. For all pollutants, stipulations to major source status may be indicated by entering "major" in the space for PTE. Indicate the total actual emissions for fee purposes for the facility in the space provided. Applications for permit modifications need not include actual emissions information.

NOx _____ tons/yr VOC 10,808 tons/yr SO2 _____ tons/yr

PM-10 _____ tons/yr CO _____ tons/yr Lead _____ tons/yr

Total HAP 200 tons/yr

Single HAP with greatest amount Toluene _____ PTE 101.6 tons/yr

Total of regulated pollutants (for fee calculation), Sec. F, line 5 of form FEE 4,000 tons/yr

K. Existing Federally-Enforceable Permits

Permit number(s) N/A Permit type _____ Permitting authority _____

Permit number(s) N/A Permit type _____ Permitting authority _____

L. Emission Unit(s) Covered by General Permits

Emission unit(s) subject to general permit N/A

Check one: ___ Application made ___ Coverage granted

General permit identifier _____ Expiration Date ____/____/____

M. Cross-referenced Information

Does this application cross-reference information? ___ YES _X_ NO (If yes, see instructions)

INSTRUCTIONS FOLLOW

INSTRUCTIONS FOR GIS, GENERAL INFORMATION AND SUMMARY

Use this form to provide general and summary information about the part 71 source (facility or plant) and to indicate the permitting action requested. Submit this form once for each part 71 source. Several sections of this form ask for information you may not know until you complete other part 71 forms.

Section A - Enter the facility's official or legal name. The contact person should be a person familiar with the day-to-day operation of the facility, such as a plant site manager or similar individual.

Section B – If different from the mailing address, include the plant site location.

Sections C and D - If more than one owner or operator, list them on an attachment.

Section E - Mark initial permit issuance if you are applying for the first time. For all types of permit revisions, applicants must provide a brief narrative description of the changes.

Section F - Indicate the broad categories of applicable requirements that apply to the facility or any emissions units. Note that acid rain requirements must be included in part 71 permits the same as other requirements. Also, see definition of "applicable requirement" in part 71. Offshore sources in Federal waters may be either Outer Continental shelf (OCS) sources or Deepwater Port Act (DPA) sources, but not both. The DPA is not an applicable requirement, but the EPA needs to know if such requirements apply because the EPA coordinates with other Federal agencies on such projects.

Section G – List emission-limiting requirements that apply to the facility as a whole, such as restrictions on potential to emit or applicable requirements that apply identically to all emission units at a facility.

Section H - List, in descending order of priority, the 4-digit standard industrial classification (SIC) code(s) that best describes your facility in terms of its principal products or processes, and provide a brief narrative description for each classification. For a listing of SIC codes, see the Standard Industrial Classification Manual, 1987 edition, prepared by the Executive Office of the President, Office of Management and Budget, from the Government Printing Office, Washington DC.

Section I - Assign a unique identifier (unit ID) under the "emissions unit ID" column and provide a text description for each significant emissions unit at facility. These IDs will be used in other part 71 forms. A "significant emissions unit" is any unit that is not an insignificant emission unit or activities. Note that unit IDs need only be assigned if they will be referenced in subsequent portions of the application. You may choose any numbering system you wish to assign unit IDs. If a unit ID was previously assigned, use the original ID. If the unit is a new unit, assign a unit ID consistent with the existing units' IDs.

You may group emissions units, activities, or pieces of equipment together and assign a single unique unit ID when they are subject to the same applicable requirement(s) and will have the same monitoring, record keeping, and reporting requirements in the permit.

In addition, assign a unit ID for each alternative operating scenario and each piece of pollution control equipment. When possible, assign these numbers to show with which emissions units or processes these scenarios or control devices are associated.

Section J – Enter the facility-wide PTE for each listed air pollutant for applicability purposes and enter the facility-wide actual emissions of all pollutants that count for fee purposes. Applications for permit revisions should report PTE after the change for the emissions units affected by the change.

Completion of form **PTE** is recommended prior to the entry of PTE information in this section.

"NOx" is for nitrogen oxides,
"VOC" is for volatile organic compounds,
"SO2" is for sulfur dioxide,
"PM10" is for particulate matter with an aerodynamic diameter of 10 micrometers or less,
"CO" is for carbon monoxide, and
"Lead" is for elemental lead regulated by a NAAQS ("compounds of lead" are HAP).

Note that the emissions of greenhouse gasses (GHGs) are not counted for major source applicability purposes or for part 71 fee purposes, so no need to enter them anywhere on this form.

Note that a source may be major for a single HAP or any combination of HAP.

Include fugitive emissions when reporting PTE to the extent that they count toward major source applicability. All fugitive emissions of HAP count toward major source applicability.

Sources may also stipulate to major source status for the pollutants indicated on the form by entering "Major" in the space provided for PTE values.

You may use the value for actual emissions from section F, line 5, of form **FEE**. When totaling actual emissions for fee purposes, include all emissions, including fugitive emissions, regardless of whether they count for applicability purposes.

Section L - If any emissions unit within your facility is applying, has applied, or currently has a general permit, identify the emissions unit ID and name of the unit, consistent with section I of this form.

Section M - Attach copies of any cross-referenced documents that are not publicly available or otherwise available to the permitting authority.

END

United States Environmental Protection Agency

OMB No. 2060-0336,
Approval Expires 05/31/2019

Federal Operating Permit Program (40 CFR Part 71)
INSIGNIFICANT EMISSIONS (IE)

On this page list each insignificant activity or emission unit. In the "number" column, indicate the number of units in this category. Descriptions should be brief but unique. Indicate which emissions criterion of part 71 is the basis for the exemption.

Number	Description of Activities or Emissions Units	RAP (except HAP)	HAP
N/A*			

* No emission sources have been listed as Insignificant Activities/ Emission Sources since the application is being submitted for obtaining both construction and operation authorization and the PSD preconstruction permitting program does not define an insignificant emissions unit.

INSTRUCTIONS FOR IE
INSIGNIFICANT ACTIVITIES

Use this form only if you have any equipment, emissions units, or emitting activities at your facility that qualify for insignificant treatment due to insignificant emissions levels (defined in the part 71 rule) and you desire such treatment.

Generally identify the source of emissions.

The "number" column is provided to indicate the total number or units or activities grouped together under one description, for example, equipment such as valves and flanges. However, units or activities that are similar should be listed separately in the form when the descriptions differ in a meaningful way, such as when capacities or sizes differ and this information is relevant, for example, to an applicability determination.

Check one of the columns provided to indicate which emission level criteria of part 71 is met for these units or activities that warrant such treatment. The rule provides 2 emission criteria:

- emissions of 2 tons per year or less or any regulated pollutants except HAP (RAP, except HAP) from any emission unit, or
- 1000 pounds per year or less of any HAP from any emission unit.

Note that part 71 does not exempt any insignificant units from major source applicability determinations.

In addition, attach to this form information concerning equipment, activities, or emissions units that are exempted from an otherwise applicable requirement (e.g., grandfathered emissions units. Please cite the basis for the exemption (e.g., State administrative code or Federal regulation).

United States Environmental Protection Agency

OMB No. 2060-0336,
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Federal Operating Permit Program (40 CFR Part 71)
EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID LOADFUG

B. Identification and Quantification of Emissions

For each emissions unit identified above, list each regulated air pollutant or other pollutant for which the source is major, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. See instructions concerning GHGs. Values should be reported to the nearest tenth (0.1) of a ton for yearly values or tenth (0.1) of a pound for hourly values.

Air Pollutants	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
VOC	N/A	7,483	10,808	
H_2S	N/A	0.16	0.24	
HAP	N/A	125	200	

NSTRUCTIONS FOR EMISS

EMISSION CALCULATIONS

Use this form to quantify emissions for each significant emissions unit identified in section I of form **GIS**. This form will help you organize emissions data needed on forms **PTE** and **FEE**. Do not complete this form for any units or activities listed as insignificant on form **IE**. Sources applying for permit revisions only need complete this form for each emissions unit affected by the change.

Section A - The emissions unit ID should be the same as that used in section I of form **GIS**.

Section B - First, list each "regulated air pollutant" that is emitted by the unit. Please list each HAP separately. Most sources will not need to provide emissions estimates for GHG because GHGs do not count in major source determinations; however, list GHGs for any unit that is subject to an emissions limitation or standard for GHGs [e.g., GHG BACT or a section 111(b) or 111(d) standard].

Second, list any "regulated pollutant (for fee calculation)" emitted at the source that has not already been listed. If you will not be submitting form FEE with your application, you do not need to perform this step or calculate actual emissions. For fee purposes, fugitive emissions count the same as stack emissions. Any HAP that has not been listed up to this point may be simply listed as "HAP." Note that GHGs, carbon monoxide, Class I or II substances under title VI, and pollutants regulated solely by section 112(r) are exempt from fee payment.

Third, calculate the actual emissions of "regulated pollutants (for fee calculation) that you listed in the step above. Actual emissions are calculated based on actual operating hours, productions rates, and in-place control equipment, and the types of materials used during the preceding calendar year. If you already have a permit, you should use the compliance methods required by the permit, such as monitoring or source test data, whenever possible; if not possible, you may use other federally recognized procedures.

Most sources will calculate actual emissions for the preceding calendar year. Sources that commenced operation during the preceding calendar year shall estimate emissions for the current calendar year. Certain sources have the option of estimating their actual emissions for the preceding calendar year, instead of calculating them based on actual emissions data, see the instructions for form **FEE** for more on this topic.

Your emission calculations may be based on generally available information rather than new source testing or studies not already required. If you have listed a pollutant but are unable to calculate its actual emissions without conducting new source testing or extensive studies, you may enter "UN" (for "unknown") in the space provided.

Values should be reported to the nearest tenth (0.1) of a ton; greater precision (i.e., more decimal places) may be used to report values if you believe it will result in a lower fee.

Fourth, calculate PTE for each "regulated air pollutant" you listed in the first step above. For pollutants not specifically regulated at this emission unit, do not calculate PTE in pounds/hour. You may stipulate that the unit alone triggers major source status for this pollutant by entering "MU" in the space provided for annual PTE values. You may stipulate that the unit does not trigger major source status, but that the aggregate facility emissions or another unit triggers major source status by entering "MS" in the space provided for annual PTE values.

Do not calculate PTE values for air pollutants listed solely for fee purposes, however, enter "NA" for "not applicable" in the space provided for PTE values for such emissions.

If you are unable to calculate PTE values for air pollutants counted for applicability purposes without conducting new source testing or extensive studies, enter "UN" (for "unknown") in the space provided.

Within applications for permit revisions, PTE should be calculated assuming the proposed change has occurred.

“Potential to emit” is defined as "the maximum capacity of a stationary source to emit any pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation is enforceable by the Administrator."

Values for PTE should be reported to the nearest tenth (0.1) of a ton or pounds (additional decimal places may be used to report values with greater precision if desired). After reviewing a submittal, the EPA may request additional information regarding the basis of the values reported on the forms (i.e., request to see values reported with greater precision, to the nearest 0.01 or 0.001).

Provide the chemical abstract service number (CAS No.), if available.

END

United States Environmental Protection Agency

OMB No. 2060-0336,
Approval Expires 05/31/2019

Federal Operating Permit Program (40 CFR Part 71)
FEE CALCULATION WORKSHEET (FEE)

Use this form initially, or thereafter on an annual basis, to calculate part 71 fees.

A. General Information

Type of fee (Check one): _X_ Initial ___ Annual

Deadline for submitting fee calculation worksheet ____/____/_____

For initial fees, emissions are based on (Check one):

_X_ Actual emissions for the preceding calendar year. (Required in most circumstances.)

____ Estimates of actual emissions for the current calendar year. (Required when operations commenced during the preceding calendar year.)

Date commenced operations ____/____/_____

___ Estimates of actual emissions for the preceding calendar year. (Optional after a part 71 permit was issued to replace a part 70 permit, but only if initial fee payment is due between January 1 and March 31; otherwise use actual emissions for the preceding calendar year.)

For annual fee payment, you are required to use actual emissions for the preceding calendar year.

B. Source Information: Complete this section only if you are paying fees but not applying for a permit.

Source or facility name _____

Mailing address: Street or P.O. Box _____

City_____ State_____ ZIP_____ - _____

Contact person_____ Title_____

Telephone (_____) _____ - _____ Ext_____ Part 71 permit no. _____

C. Certification of Truth, Accuracy and Completeness: Only needed if not submitting a separate form CTAC.

I certify under penalty of law, based on information and belief formed after reasonable inquiry, the statements and information contained in this submittal (form and attachments) are true, accurate and complete.

Name (signed) Denise Rogers

Name (typed) Denise Rogers Date: 10 / 26 / 18

D. Annual Emissions Report for Fee Calculation Purposes -- Non-HAP

You may use this to report actual emissions (tons per year) of regulated pollutants (for fee calculation) on a calendar-year basis for both initial and annual fee calculation purposes. Section E is designed to report HAP emissions. Quantify all actual emissions, including fugitives, but do not include insignificant emissions and certain regulated air pollutants that are not counted for fee purposes, such as CO and GHGs (see instructions). Sum the emissions in each column to calculate subtotals. Subtotals should be reported to the nearest tenth (0.1) of a ton at the bottom of the page. If any subtotal exceeds 4,000 tons, enter 4,000 for that column.

This data is for See Note 1 below (year)

Emission Unit ID	NOx	VOC	SO2	PM10	Lead	Other
LOADFUG (Marine Loading)		0				0
SUBTOTALS:		0				0

Note 1 – The proposed project has not yet commenced operation and therefore actual emissions are zero for all pollutants.

E. Annual Emissions Report for Fee Calculation Purposes -- HAP

HAP Identification. Identify individual HAP emitted at the facility, identify the CAS number, and assign a unique identifier for use in the second table in this section. Whenever assigning identifier codes, use "HAP1" for the first, "HAP2" for the second, and so on.

Name of HAP	CAS No	Identifier
Benzene	71-43-2	HAP1
Toulene	108-88-3	HAP2

HAP Emissions. Report the actual emissions of individual HAP identified above. Use the identifiers assigned in the table above. Include all emissions, including fugitives, and do not include insignificant emissions. Sum the emissions in each column to calculate subtotals. Report subtotals to the nearest tenth (0.1) of a ton at the bottom of the page. If any subtotal exceeds 4,000 tons, enter 4,000.

This data is for See Note 1 below (year)

Emissions Unit ID	Actual Emissions (Tons/Year)							
	HAP1	HAP2						
LOADFUG (Marine Loading)	0	0						
SUBTOTALS:	0	0						

Note 1 – The proposed project has not yet commenced operation and therefore actual emissions are zero for all pollutants.

F. Fee Calculation Worksheet

This worksheet is used to calculate the total fee owed (including the emissions-based fee and the GHG fee adjustment) for both initial and annual fee payment purposes. Reconciliation is only for cases where you are paying the annual fee and you used any type of estimate of actual emissions when you calculated the initial fee. If you do not need to reconcile fees, complete line 1-5 (emissions summary) and then skip down to line 21 (emission calculation). See instructions for more detailed explanation.

EMISSIONS SUMMARY

1. Sum the subtotals from section D of this form (non-HAP) and enter the total, rounded to the nearest tenth (0.1) of a ton.	0
2. Sum the subtotals from section E of this form (HAP) and enter the total, rounded to the nearest tenth (0.1) of a ton.	0
3. Sum lines 1 and 2.	0
4. Enter the emissions that were counted twice. If none, enter "0."	0
5. Subtract line 4 from line 3, round to the nearest ton, and enter the result here. This is the **total emissions** that count for fees purposes.	0

RECONCILIATION
(WHEN INITIAL FEES WERE BASED ON ESTIMATES FOR THE "CURRENT" CALENDAR YEAR)

Only complete lines 6-10 if you are paying the first annual fee and initial fees were based on estimated actual emissions for the calendar year in which you paid initial fees; otherwise skip to line 11 or to line 21.

6. Enter the total estimated actual emissions for the year the initial fee was paid (previously reported on line 5 of the initial fee form).	N/A
7. If line 5 is greater than line 6, subtract line 6 from line 5, and enter the result. Otherwise enter "0."	
8. If line 6 is greater than line 5, subtract line 5 from line 6, and enter the result. Otherwise enter "0."	
9. If line 7 is greater than 0, multiply line 7 by last year's fee rate ($/ton) and enter the result here. This is the underpayment. Go to line 21.	
10. If line 8 is greater than 0, multiply line 8 by last year's fee rate ($/ton) and enter the result here. This is the overpayment. Go to line 21.	

RECONCILIATION
(WHEN INITIAL FEES WERE BASED ON ESTIMATES FOR THE "PRECEDING" CALENDAR YEAR)

Only complete lines 11-20 if you are paying the first annual fee and initial fees were based on estimated actual emissions for the calendar year preceding initial fee payment; otherwise skip to line 21. If completing this section, you will also need to complete sections D and E to report actual emissions for the calendar year preceding initial fee payment.

11. Sum the actual emissions from section D (non-HAP) for the calendar year preceding initial fee payment and enter the result here.	N/A
12. Sum the actual emissions from section E (HAP) for the calendar year preceding initial fee payment and enter the result here.	
13. Add lines 11 and 12 and enter the total here. These are total actual emissions for the calendar year preceding initial fee payment.	
14. Enter double counted emission from line 13 here. If none, enter "0."	
15. Subtract line 14 from line 13, round to the nearest ton, and enter the result here.	
16. Enter the total estimated actual emissions previously reported on line 5 of the initial fee form. These are estimated actual emissions for the calendar year preceding initial fee payment.	
17. If line 15 is greater than line 16, subtract line 16 from line 15, and enter the result here. Otherwise enter "0."	
18. If line 16 is greater than line 15, subtract line 15 from line 16, and enter the result here. Otherwise enter "0."	
19. If line 17 is greater than 0, multiply line 17 by last year's fee rate ($/ton) and enter the result here. This is the underpayment.	
20. If line 18 is greater than 0, multiply line 18 by last year's fee rate ($/ton) and enter the result on this line. This is the overpayment.	
EMISSION FEE CALCULATION	
21. Multiply line 5 (tons) by the current fee rate ($/ton) and enter the result here. This is the unadjusted emissions fee. Continue on to line 23.	0
GHG FEE ADJUSTMENT	
22. If you are submitting an initial permit application and this is the first time you are paying fees, enter $2,236, otherwise enter "0". [Note that any updates to the initial application are covered under this one-time charge.]	0
23. Enter the number of permit modifications (or related permit actions) you have submitted to the permitting authority since you last paid fees. If none, skip to line 25.	0
24. Multiply the number in line 23 by $365 and enter the result.	0

25. If you have submitted a permit renewal application since the last time you paid fees enter $520, otherwise enter "0"	0
26. Sum line 22, 24, and 25 and enter the result. This is the GHG fee adjustment	0
OTHER ADJUSTMENTS	
27. Add the total on line 21 and the total on line 26 and enter the result.	0
28. Enter any underpayment from line 9 or 19 here. Otherwise enter "0."	0
29. Enter any overpayment from line 10 or 20 here. Otherwise enter "0."	0
30. If line 28 is greater than "0," add it to line 27 and enter the result here. If line 29 is greater than "0," subtract this from line 27 and enter the result here. Otherwise enter the amount on line 27 here. This is the fee adjusted for over/underpayment.	0
31. Enter any credit for fee assessment error here. Otherwise, enter "0."	0
32. Subtract line 31 from line 30 and enter the result here. Stop here. This is the **TOTAL FEE (AFTER ADJUSTMENTS)** that you must remit to EPA.	0

INSTRUCTIONS FOR FEE
FEE CALCULATION WORKSHEET

Information Collection Burden Estimates

The public reporting and recordkeeping burden for this collection of information is estimated to average 247 hours per respondent per year. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW, Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed form to this address.

DETAILED INSTRUCTIONS

Use this form to initially or annually calculate fees. This form is for paying fees to EPA or a delegate agency (such as a State or tribe) under a part 71 operating permit program. The requirements for paying fees under part 71 programs, as well as the forms and instructions contained herein, are based on the requirements of 40 CFR 71.9

There may be cases, under a part 71 program, when you are not required to complete this form or pay the EPA fee rate (where the part 71 program has been delegated and EPA's fee has been suspended because EPA incurs no administrative costs). In such cases, the delegate agency will instruct you on how to calculate fees and how to pay them. If in doubt, contact your permitting authority.

General Rules for Fee Calculation under Part 71:

- Use the fee rate in effect at the time you pay the fee regardless of the time period that the emissions data represents. For example, if the annual fee for the current year is due July 1, you would use the fee rate in effect for the current year and the actual emissions for the previous calendar year.
- Do not prorate initial or annual fees. Pay full fees for the entire calendar year regardless of how many days you operated or were subject to the program during the previous or current year.
- Do not hesitate to contact the permitting authority if you have any doubt about how to calculate fees, especially if you have an unusual set of circumstances not addressed specifically by these forms or whenever the permit requirements appear to conflict with these forms (however, always assume the permit requirements take precedence in such cases).

Section A. General Information

The deadline for submitting the fee form and paying the fee for initial fee payment purposes for most sources is the same deadline as for submitting all other forms required for the initial permit application. Other deadlines apply for initial fee payment in certain limited circumstances:

- When a source is subject to part 71 because of an unresolved EPA objection to a part 70 permit, fees are not due with the part 71 application, but are due 3 months following the date of the issuance of the part 71 permit.
- When EPA withdraws approval of a part 70 program and implements a part 71 programs, fees are submitted according to a schedule based on the source's SIC code (within 6 to 9 months of the effective date of the part 71 program).

The deadline for submitting the fee form and paying the fee for annual fee payment purposes is the anniversary date of initial fee payment. This is required whether or not a permit has been issued. If you were required to pay initial fees between January 1 and March 31, the regulations allow for submittal of annual fees no later than April 1.

Whether you are paying initial or annual fees see the instructions for sections D and E for more information on which calendar-year emission data to use (preceding or current year) and how to quantify such emissions (actual emissions or estimates of actual emissions).

Section B. Source Information

Complete this section only if you are preparing this form for submittal at a different time than for the other portions of an initial application or for annual fee purposes.

Section C. Certification of Truth, Accuracy and Completeness

This form and any other document required by a permit must be signed by a responsible official certifying truth, accuracy and completeness of the information. If you are submitting a separate **CTAC** form, there is no need to complete this section of the form. If you complete this section, there is no need to submit form **CTAC** separately.

Section D. Annual Emissions Report for Fee Calculation Purposes – Non-HAP

Calculate actual emissions of regulated pollutants (for fee calculation), except for HAP, on a calendar-year basis for the facility in this section. Section E is provided to report actual emissions of HAP. Note the phrase "regulated pollutant (for fee calculation)" is any "regulated air pollutant" except carbon monoxide (CO), and pollutants regulated solely because they are: 1) subject to regulation under section 112(r) of the Act, or 2) a class I or II substance under title VI of the Act. **Note that GHG emissions are not counted for fee purposes.**

If more than one year of data is being submitted with the fee calculation worksheet, copy this page and complete a separate table for each year. If you are submitting an initial application, you may use emissions data already reported on form **EMISS**, provided this is the same data you would otherwise report in sections D and E of this form. If using **EMISS** in this manner, please note this on the fee calculation form. Also, sources must submit attachments to this form to show (at a minimum) examples of the calculations used to determine these values.

Show actual emissions for each listed air pollutant for each emission unit. Values should be reported to the nearest tenth (0.1) of a ton.

The column for "other" is for other regulated pollutants (for fee calculation) not already listed on the form. Write in the name of the pollutant in the proximity of the "other" column. If more than one such pollutant, show the pollutants, and the totals on an attachment.

Actual emissions must be calculated using actual operating hours, production rates, in-place control equipment, and types of materials processed, stored, or combusted over the preceding calendar year. Sources that have been issued title V permits are required to compute actual emissions using compliance methods required by the permits, such as monitoring or source testing data. If this is not possible, actual emissions should be determined using other federally recognized procedures.

For initial fee calculation purposes, most sources are required to use actual emissions for the preceding calendar year. However, there are certain exceptions where estimates of actual emissions are either required or allowed in place of actual emissions for the preceding calendar year (see table below):

Exception	Emission Data
When the source commenced operation during the preceding calendar year.	Estimates of actual emissions for the "current" calendar year are required
When EPA withdraws approval of a part 70 program and implements a part 71 program, and the source pays initial part 71 fees between January 1 and March	Either estimates of actual emissions for the "preceding" calendar year or actual emissions for the preceding calendar year may be used.
When a part 71 permit was issued following an unresolved objection to a part 70 permit, and the source is required to pay initial part 71 fees between January 1 and March 31.	Either estimates of actual emissions for the "preceding" calendar year or actual emissions for the preceding calendar year may be used.

For annual fee purposes, fee calculation should be based on actual emissions for the preceding calendar year in all cases.

In most cases you will only need to report one set of emission data using sections D and E of this form (the data that is the basis of the initial or annual fee being paid as explained above). This data is subsequently carried over to lines 1 and 2 of section F (Fee Calculation Worksheet) of the form.

However, there is one exception where you would be required to report two different sets of emissions data using sections D and E – when paying the first annual fee and reconciliation is required because the initial fee was based on estimated actual emissions for the "preceding" calendar year (the year preceding initial fee payment). In this case, the two data sets would be:

- actual emissions for the year initial fees paid (for annual fee purposes in lines 1-5 of section F of the form), and
- actual emissions for the year preceding initial fee payment (for reconciliation in lines 11-20 of the form)

Whenever reconciliation is required as part of annual fee payment, you will also need a copy of the fee forms you previously submitted with initial fee payment in order to obtain the value of estimated actual emissions.

Include all fugitive emissions in the calculation of actual emissions, including those that do not count for applicability. Do not include any insignificant emissions identified on form **IE**.

The subtotal line in section D of the form is provided at the bottom of each column to enter total emissions for each pollutant reported above. Each subtotal should be reported to the nearest tenth (0.1) of a ton. If any subtotal exceeds 4,000 tons, enter 4,000 tons for that column.

Any necessary adjustments for double counting of emissions will be performed later in section F.

Section E. Annual Emissions Report for Fee Calculation Purposes -- HAP

List the actual emissions of individual HAP from each emission unit. If you are initially applying for a permit, you may use the emissions of HAP reported on form **EMISS,** instead of completing this section of this form, provided these emissions are the same as you would otherwise report using this section of the form. If you are doing this, please note it on the form.

This section is composed of two tables. The first table is to identify individual HAP emitted at each emission unit. Assign a unique identifier for use in the second table. Please use "HAP1" for the first

one, "HAP2" for the second one, and so on. The second table is to calculate the actual emission of individual HAP at each emission unit. Use the identifiers assigned in the first table to label the column headers for the second table. You may round and report these emissions to the nearest tenth (0.1) of a ton. Sum the values in each column and enter the subtotals at the bottom of the table. If any subtotal exceeds 4,000 tons, enter 4,000 for that column.

See instructions for section D for more information on reporting emissions data.

Section F. Fee Calculation Worksheet

This worksheet is used to sum the total tons of actual emissions subject to fees, adjust for double counting of emissions, perform certain reconciliations for underpayment and overpayment of fees and adjust for fee assessment errors, if needed, and ultimately to determine the total fee to be paid.

A detailed explanation of Section F follows (separated into six parts):

Emissions Summary

The subtotals for each pollutant listed in Sections D and E (or from form **EMISS**) are added together to calculate the total emissions (in tons per year) for the facility.

The emissions that are reported here will vary for initial fee payment purposes, depending on the specific circumstances, but will always be actual emissions for the preceding calendar year for annual fee purposes. See the instructions for section D for more on the emissions data you should use in the part of the form.

The total emissions are adjusted for double counting and are rounded to the nearest ton. For example, double counting may occur where a pollutant is defined as HAP and VOC. If you adjust for double counting, attach an explanation for this.

Reconciliation (When Initial Emission Fees Were Based on Estimates for the Current Calendar Year)

This section is only used by sources paying their first annual fee when their initial fee was based on estimates of calendar-year emissions for the "current" year (the same year that initial fees were paid). This reconciliation is done by comparing the actual emissions for the "current" year provided in sections D and E of this submittal with the estimate of those emissions previously provided with initial fee payment. There may have been overpayment or underpayment of the initial fee. The fee you are paying now will be adjusted for this difference later.

Reconciliation (When Initial Emission Fees Were Based on Estimates for the Preceding Calendar Year)

This section is only used by sources paying their first annual fee when their initial fee was based on estimates of calendar-year emissions for the year preceding initial fee payment, provided the source was required to pay its initial fee between January 1 and March 31, and EPA issued the Part 71permit to replace a Part 70 permit. This reconciliation is done by comparing the actual emissions for the "preceding" year provided in sections D and E of this submittal with the estimate of those emissions provided with initial fee payment. There may have been overpayment or underpayment of the initial fee. The fee you are paying now will be adjusted for this difference later.

Emission Fee Calculation

Calculate the emission-based fee using the emissions from line 5 (tons) multiplied by the fee rate ($/ton) in effect at the time the fee is paid.

GHG Fee Adjustment

The part 71 rule was amended in 2015 to require the fees to be increased by a GHG fee adjustment. The GHG adjustment must be calculated by each source that is required to pay fees. The adjustment is based on the burden for the permitting authority to conduct certain GHG evaluations or reviews related to the source, rather than on emissions. Set fees are charged for certain activities that have occurred at the source since the last time fees were paid. For an initial application, the set fee is a one-time charge that includes the costs of processing application updates. The term "permit modification" refers to any significant and minor modifications, but not to administrative amendments. The number of permit modifications must be multiplied by the set fee for modifications to determine the total GHG adjustment for modifications. The set fee for a permit renewal also includes any permit modifications that may be processed at the same time as the renewal. Note that you may need to check with the permitting authority to determine if they are holding any permit modification requests you have submitted for processing with an upcoming permit renewal.

Other Adjustments

The purpose of this section is to adjust the emissions-based to determine the total fee (after adjustments) that is due to the EPA. The emissions fee determined on line 21 is adjusted by the GHG fee adjustment, any amounts of overpayment or underpayment related to a previous fee submittal, and to correct for any fee assessment errors.

Fee assessment errors occur when the permitting authority determines that the source has calculated the fee incorrectly. If this occurs, you will be notified of the error. Any overpayment will be credited against the next fee owed. In the case of underpayment, you will be billed for the corrected fee and you will have 30 days to remit the amount. If you think the assessed fee is in error, you may submit a written explanation of the alleged error, but you must pay the fee. The permitting authority will provide a determination in 90 days. If the assessment of underpayment is in error, your account will be credited.

Fee Payment

See form **FF** (the Fee Filing form) for instructions on how to make fee payment to the EPA.

Penalties and Interest

The permitting authority will bill sources for appropriate penalties and interest for late payment or excessive underpayment of fees. Interest will be assessed on payments received later than the due date. Penalties shall be assessed if payment is not paid within 30 days of the due date. For sources issued with issued permits, penalties and interest shall be assessed for excessive underpayment of the annual fee amount.

END

United States Environmental Protection Agency

OMB No. 2060-0336,
Approval Expires 05/31/2019

Federal Operating Permit Program (40 CFR Part 71)
FEE FILING FORM (FF)

The purpose of this form is to ensure that fee payments made by check are credited to the proper facility and to the proper government account. Send this form, along with form **FEE** and the check, to the appropriate lockbox bank address listed on the following page. This form is required whenever you pay by check, including for initial and annual fee payments. Part 71 fees may be paid by check or electronically, and further information on making payments by check or electronically is provided on the following page.

Source or Facility Name Texas Gulf Terminals Inc.

Source Location Site is approximately 14 miles offshore the coast of Texas, Southeast of Corpus Christi. Latitude N27° 28' 42.6" and Longitude W97° 00' 48.43".

EPA Region where Source Located 6

Mailing Address:

Street/P.O. Box 1401 McKinney, Suite 1500

City Houston

State TX ZIP 77010 - _____

Contact Person: Denise Rogers

Title: Compliance Manager

Telephone (832) 203 - 6493 Ext. _____

Total Fee Payment Remitted: $ 0

TWO PAYMENT OPTIONS FOR PART 71 FEES:

OPTION 1 - CHECK PAYMENT VIA U.S. POSTAL SERVICE

- Fee payment shall be in U.S. currency drawn on a U.S. bank.
- Check should be made out to the order of the "U.S. Environmental Protection Agency."
- Indicate on the check that the payment is for "Part 71 Fee Payment."
- Make a photocopy of the check.

- **Send the following to the EPA region (or delegate agency):**
  - ✓ Form *FEE* (EPA Form 5900-03) and
  - ✓ Photocopy of check

- **Send the following to one of the addresses below:**
  - ✓ Form *FF* (EPA Form 5900-06) and
  - ✓ Original check

***Address* for *Regular Mail* (U.S. Postal Service):**	**Address *for Express Delivery* (or If Physical Address is Required):**
U.S. EPA FOIA and Misc. Payments Cincinnati Finance Center PO Box 979078 St. Louis, MO 63197-9000	U.S. Bank Government Lockbox 979078 US EPA FOIA & Misc. Payments 1005 Convention Plaza Mail Station SL-MO-C2-GL St. Louis, MO 63101

- **Tips for Completing form FF (Fee Filing Form)**
  - ***Source Location:*** Physical location - Street address (if any), City, County, and State.
  - ***Mailing Address:*** Address for the EPA to send correspondence. This address may be different from the source location, such as a corporate office.
  - ***EPA Region:*** EPA region in which the source is located (e.g., EPA Region 8).
  - ***Contact:*** Person that can best answer questions concerning fee payment.

OPTION 2 – ONLINE PAYMENT

- Part 71 fees can be paid online at www.pay.gov using form **"SFO 1.1 (EPA Miscellaneous Payments - Cincinnati Finance Center)."** *Note that EPA Form 5900-06 cannot be used for online payments.*

- **Tips for completing online form SFO 1.1:**
  - From the "*Type of Payment*" drop down menu, select "Other/Miscellaneous"
  - On the "*Bill# or description*" line, enter "Part 71 Fee Payment"
  - In the "*Comments*" box, enter the source or facility name and the part 71 permit number associated with this payment.

- **After submitting payment online, send the following to the EPA region (or delegate agency):**
  - Form *FEE* (EPA Form 5900-03) and
  - Copy of the electronic payment confirmation generated by the online payment system.

- **FOR MORE INFORMATION:** The following link provides detailed information on how to make payments to EPA for part 71 fees, penalties, and interest, including contact information for EPA's Accounts Receivable Branch in Cincinnati https://www.epa.gov/financial/makepayment

  Contacts: Craig Steffen (US EPA Finance): 513-487-2091
  Natalie Pearson (U.S. Bank): 314-418-4087

United States Environmental Protection Agency

OMB No. 2060-0336,
Approval Expires 05/31/2019

Federal Operating Permit Program (40 CFR Part 71)
INITIAL COMPLIANCE PLAN AND COMPLIANCE CERTIFICATION (I-COMP)

SECTION A - COMPLIANCE STATUS AND COMPLIANCE PLAN

Complete this section for each unique combination of applicable requirements and emissions units at the facility. List all compliance methods (monitoring, recordkeeping and reporting) you used to determine compliance with the applicable requirement described above. Indicate your compliance status at this time for this requirement and compliance methods and check "YES" or "NO" to the follow-up question.

Emission Unit ID(s): LOADFUG

Applicable Requirement (Describe and Cite)

N/A

Compliance Methods for the Above (Description and Citation):

N/A

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes ____No

Emission Unit ID(s):

Applicable Requirement (Description and Citation):

Compliance Methods for the Above (Description and Citation):

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes ____No

B. SCHEDULE OF COMPLIANCE

Complete this section if you answered "NO" to any of the questions in section A. Also, complete this section if required to submit a schedule of compliance by an applicable requirement. Please attach copies of any judicial consent decrees or administrative orders for this requirement.

Unit(s)_____ Requirement_____

Reason for Noncompliance. Briefly explain reason for noncompliance at time of permit issuance or that future-effective requirement will not be met on a timely basis:

Narrative Description of how Source Compliance Will be Achieved. Briefly explain your plan for achieving compliance:

Schedule of Compliance. Provide a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance, including a date for final compliance.

Remedial Measure or Action	Date to be Achieved

C. SCHEDULE FOR SUBMISSION OF PROGRESS REPORTS

Only complete this section if you are required to submit one or more schedules of compliance in section B or if an applicable requirement requires submittal of a progress report. If a schedule of compliance is required, your progress report should start within 6 months of application submittal and subsequently, no less than every six months. One progress report may include information on multiple schedules of compliance.

Contents of Progress Report (describe):

First Report____/____/___ Frequency of Submittal_____

Contents of Progress Report (describe):

First Report____/____/___ Frequency of Submittal_____

D. SCHEDULE FOR SUBMISSION OF COMPLIANCE CERTIFICATIONS

This section must be completed once by every source. Indicate when you would prefer to submit compliance certifications during the term of your permit (at least once per year).

Frequency of submittal_____ Beginning____/____/____

E. COMPLIANCE WITH ENHANCED MONITORING & COMPLIANCE CERTIFICATION REQUIREMENTS

This section must be completed once by every source. To certify compliance with these, you must be able to certify compliance for every applicable requirement related to monitoring and compliance certification at every unit.

Enhanced Monitoring Requirements: ____ In Compliance ____ Not In Compliance

Compliance Certification Requirements: ____ In Compliance ____ Not In Compliance

INSTRUCTIONS FOR I-COMP

INITIAL COMPLIANCE PLAN AND COMPLIANCE CERTIFICATION

Section A (Compliance Status and Compliance Plan)

Description of Applicable Requirement: Complete Section A for each unique combination of applicable requirements (emission limitations, standards or other similar requirements of federal rules, SIP, TIP, FIP, or federally-enforceable permits) that apply to particular emissions units. You will likely have to complete this section numerous times to include all requirements at all emission units.

The emissions unit ID(s) should be the ones defined in section I of form GIS. If the requirement, including compliance method, applies in the same way to multiple emission units, you may list multiple units for a particular requirement.

The descriptions here should be detailed to the individual requirement level, rather than the standard level (if a MACT applies to you, describe each requirement of the MACT, rather than just a citation to the MACT as a whole). If the requirement imposes a particular numerical limit or range, include that in your description.

Citations to the requirements should unambiguously identify the requirement to the lowest level necessary.

Compliance Methods: List all compliance methods (monitoring, recordkeeping and reporting) you used to determine compliance with the applicable requirement described above. Such methods may be required by the applicable requirements or performed for other reasons. List all compliance methods required by applicable requirements, whether you used them to determine compliance or not.

To describe monitoring, indicate the monitoring device, the equipment, process, or pollutant monitored, averaging time, frequency, and a citation or cross-reference to the requirement. To describe recordkeeping, describe the records kept, the frequency of collection, and include a citation or cross-reference to the requirement. Please indicate whether monitoring data, results, or other records kept for compliance purposes may be kept on-site rather than reported. To describe reporting requirements, describe what is reported, when it is reported, and cite or cross-reference the requirement.

The citation or cross-reference here must unambiguously identify the requirement to the lowest level necessary.

Note that Compliance Assurance Monitoring (CAM) under part 64 is also an applicable requirement that may impose compliance methods for title V sources and require the submittal of a CAM plan with this application. Also note that periodic monitoring (which may be monitoring or recordkeeping designed to serve as monitoring) under part 71 may be required in certain limited circumstances: when there is no monitoring required, monitoring is required but there is no frequency specified, or only a one-time test is required. You may propose periodic monitoring in your application, but the permitting authority will make the final decision. If you wish to propose periodic monitoring, please do so in an attachment that clearly identifies the requirements, the units they apply to, and what you propose for periodic monitoring.

Compliance Status: For each requirement and associated compliance methods described above, indicate whether you are in compliance, not in compliance, or it is a future-effective requirement (only check one). This is with respect to your compliance status at the time of application submittal. You should consider all available information or knowledge that you have when evaluating your compliance status, including reference test methods and other compliance requirements that are required directly by a statute, regulation, or permit and "credible evidence" (e.g., non-reference test methods and other information "readily available" to you and already being utilized by you). For each compliance status indication, you must answer "YES" or "NO" as to your expectations for continuing (or future) compliance. If you answer "NO" to any of these questions, you will have to complete the schedule of compliance section (section B).

Section B (Schedule of Compliance)

Complete this section if you answered "NO" to any of the questions in section A. Regardless of how you answered the questions in section A, complete this section if required to have a schedule of compliance by an applicable requirement, or if a judicial consent decree or administrative order includes a schedule of compliance.

Identify the applicable requirement using the same information you used in section A. Provide a brief explanation of the reason for noncompliance (either now or in the future). [e.g., "do not have control device required as BACT."] Next, provide a brief description of what the schedule of compliance is trying to achieve. Then in the table provided, include a detailed schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with the applicable requirement. This schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the source is subject. Any such schedule of compliance must be supplemental to, and not sanction noncompliance with, the applicable requirements on which it is based. For each remedial measure, provide the date by which the action will be completed. This schedule or one approved by the permitting authority will be included in the permit.

Lastly, attach a copy of any judicial consent decrees or administrative orders for which you are providing a schedule of compliance.

Section C (Schedule for Submission of Progress Reports)

If you must submit one or more schedules of compliance (specified in section B), or if an applicable requirement requires submittal of a progress report, complete this section. Progress reports describe your progress in meeting the milestone dates for the remedial measures required by the schedule of compliance. Progress reports must be submitted at least every 6 months, but specific applicable requirements may require them more frequently. One progress report may include information on one or more schedules of compliance. Describe the contents of the progress report, including the date that your facility will begin submitting them and the frequency they will be submitted.

Section D (Schedule for Submission of Compliance Certifications)

All applicants must complete this section. Compliance certifications must be submitted at least every year unless the applicable requirement or EPA requires them more frequently. Provide the date when the first compliance certification will be sent.

Section E (Compliance Status for Enhanced Monitoring and Compliance Certification)

All applicants must complete this section. The completion of this section does not satisfy the requirement for the responsible official to submit a certification of truth, accuracy, and completeness (instead, this is met by completing form CTAC and submitting it with the other forms you send to EPA).

To certify compliance with "Enhanced Monitoring," you must be in compliance at all emission units with CAM and "Periodic Monitoring" [required by 40 CFR 71.6(a)(3)(i)(B)], if they apply. "Compliance Certification Requirements" include requirements for compliance certification in title V applications and permits, and possibly through applicable requirements (e.g., certain MACT standards). If you have fully completed sections A - E of this form, you will be in compliance with the compliance certification requirement for applications. If you do not have a title V permit at this time, you can assume you are in compliance with the compliance certification requirements for permits and with periodic monitoring requirements. If you indicate you are "not in compliance" with either of these requirements, attach an explanation.

END

United States Environmental Protection Agency

OMB No. 2060-0336,
Approval Expires 05/31/2019

Federal Operating Permit Program (40 CFR Part 71)
CERTIFICATION OF TRUTH, ACCURACY, AND COMPLETENESS (CTAC)

This form must be completed, signed by the "Responsible Official" designated for the facility or emission unit, and sent with each submission of documents (i.e., application forms, updates to applications, reports, or any information required by a part 71 permit).

A. Responsible Official

Name: (Last) Rogers (First) Denise (MI) ____

Title Compliance Manager

Street or P.O. Box 1401 McKinney, Suite 1500

City Houston State TX ZIP 77010

Telephone (832) 203 - 6493 Ext. ____ Facsimile (832) 203 - 6401

B. Certification of Truth, Accuracy and Completeness (to be signed by the responsible official)

I certify under penalty of law, based on information and belief formed after reasonable inquiry, the statements and information contained in these documents are true, accurate and complete.

Name (signed) Denise Rogers

Name (typed) Denise Rogers Date: 6 / 27 / 2018

INSTRUCTIONS FOR CTAC
CERTIFICATION OF TRUTH, ACURACY, and COMPLETENESS

Information Collection Burden Estimates

The public reporting and recordkeeping burden for this collection of information is estimated to average 247 hours per respondent per year. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW, Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed form to this address.

DETAILED INSTRUCTIONS

This form is for the responsible official to certify that submitted documents (i.e., permit applications, updates to application, reports, and any other information required to be submitted as a condition of a permit) are true, accurate, and complete.

This form should be completed and submitted with each set of documents sent to the permitting authority. It may be used at time of initial application, at each step of a phased application submittal, for application updates, as well as to accompany routine submittals required as a term or condition of a permit.

Section A - Title V permit applications must be signed by a responsible official. The definition of responsible official can be found at 40 CFR 70.2.

Section B - The responsible official must sign and date the certification of truth, accuracy and completeness. This should be done after all application forms are complete and the responsible official has reviewed the information. Normally this would be the last form completed before the package of forms is mailed to the permitting authority.

TCEQ Core Data Form

TCEQ Use Only

For detailed instructions regarding completion of this form, please read the Core Data Form Instructions or call 512-239-5175.

SECTION I: General Information

1. Reason for Submission (If other is checked please describe in space provided.)

☒ New Permit, Registration or Authorization (Core Data Form should be submitted with the program application.)

☐ Renewal (Core Data Form should be submitted with the renewal form) ☐ Other

2. Customer Reference Number (if issued)	Follow this link to search for CN or RN numbers in Central Registry**	3. Regulated Entity Reference Number (if issued)
CN 605490085		RN

SECTION II: Customer Information

4. General Customer Information | 5. Effective Date for Customer Information Updates (mm/dd/yyyy)

☐ New Customer ☐ Update to Customer Information ☐ Change in Regulated Entity Ownership
☐ Change in Legal Name (Verifiable with the Texas Secretary of State or Texas Comptroller of Public Accounts)

The Customer Name submitted here may be updated automatically based on what is current and active with the Texas Secretary of State (SOS) or Texas Comptroller of Public Accounts (CPA).

6. Customer Legal Name (If an individual, print last name first: e.g.: Doe, John) | If new Customer, enter previous Customer below:

Texas Gulf Terminals Inc.

7. TX SOS/CPA Filing Number	8. TX State Tax ID (11 digits)	9. Federal Tax ID (9 digits)	10. DUNS Number (if applicable)
0802978324	32066715692		

11. Type of Customer: ☒ Corporation ☐ Individual Partnership: ☐ General ☐ Limited
Government: ☐ City ☐ County ☐ Federal ☐ State ☐ Other ☐ Sole Proprietorship ☐ Other:

12. Number of Employees
☒ 0-20 ☐ 21-100 ☐ 101-250 ☐ 251-500 ☐ 501 and higher

13. Independently Owned and Operated?
☒ Yes ☐ No

14. Customer Role (Proposed or Actual) - as it relates to the Regulated Entity listed on this form. Please check one of the following:

☐ Owner ☐ Operator ☒ Owner & Operator
☐ Occupational Licensee ☐ Responsible Party ☐ Voluntary Cleanup Applicant ☐ Other:

15. Mailing Address:							
	1401 McKinney						
	Suite 1500						
	City	Houston	State	TX	ZIP	77010	ZIP + 4

16. Country Mailing Information (if outside USA)	17. E-Mail Address (if applicable)

18. Telephone Number	19. Extension or Code	20. Fax Number (if applicable)
(832) 203 - 6400		( ) -

SECTION III: Regulated Entity Information

21. General Regulated Entity Information (If `New Regulated Entity" is selected below this form should be accompanied by a permit application)

☒ New Regulated Entity ☐ Update to Regulated Entity Name ☐ Update to Regulated Entity Information

The Regulated Entity Name submitted may be updated in order to meet TCEQ Agency Data Standards (removal of organizational endings such as Inc, LP, or LLC).

22. Regulated Entity Name (Enter name of the site where the regulated action is taking place.)

Texas Gulf Terminals Project

23. Street Address of the Regulated Entity: (No PO Boxes)							
	City		State		ZIP		ZIP + 4
24. County							

Enter Physical Location Description if no street address is provided.

25. Description to Physical Location:	Site is approximately 14 miles offshore the coast of Texas, Southeast of Corpus Christi.

26. Nearest City	State	Nearest ZIP Code
N/A	TX	N/A

27. Latitude (N) In Decimal:	27.4785		28. Longitude (W) In Decimal:	97.013453	
Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
27	28	42.6	97	00	48.43

29. Primary SIC Code (4 digits)	30. Secondary SIC Code (4 digits)	31. Primary NAICS Code (5 or 6 digits)	32. Secondary NAICS Code (5 or 6 digits)
4612		486910	

33. What is the Primary Business of this entity? (Do not repeat the SIC or NAICS description.)

Offshore Marine Terminal

34. Mailing Address:	1401 McKinney						
	Suite 1500						
	City	Houston	State	TX	ZIP	77010	ZIP + 4
35. E-Mail Address:							

36. Telephone Number	37. Extension or Code	38. Fax Number (if applicable)
(832) 203 - 6400		( ) -

39. **TCEQ Programs and ID Numbers** Check all Programs and write in the permits/registration numbers that will be affected by the updates submitted on this form. See the Core Data Form instructions for additional guidance.

☐ Dam Safety	☐ Districts	☐ Edwards Aquifer	☐ Emissions Inventory Air	☐ Industrial Hazardous Waste
☐ Municipal Solid Waste	☐ New Source Review Air	☐ OSSF	☐ Petroleum Storage Tank	☐ PWS
☐ Sludge	☐ Storm Water	☒ Title V Air	☐ Tires	☐ Used Oil
☐ Voluntary Cleanup	☐ Waste Water	☐ Wastewater Agriculture	☐ Water Rights	☐ Other:

SECTION IV: Preparer Information

40. Name: Denise Rogers			41. Title: Compliance Manager
42. Telephone Number	43. Ext./Code	44. Fax Number	45. E-Mail Address
(832) 203 - 6493		( ) -	denise.rogers@texasgulfterminals.com

SECTION V: Authorized Signature

46. By my signature below, I certify, to the best of my knowledge, that the information provided in this form is true and complete, and that I have signature authority to submit this form on behalf of the entity specified in Section II, Field 6 and/or as required for the updates to the ID numbers identified in field 39.

Company:	Texas Gulf Terminals Inc	Job Title:	Compliance Manager
Name(*In Print*):	Denise Rogers	Phone:	(832) 203-6493
Signature:	Denise Rogers	Date:	6/28/2018

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

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

I. Applicant Information		
A. Company or Other Legal Name: Texas Gulf Terminals Inc.		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Information: (☐ Mr. ☐ Mrs. ☒ Ms. ☐ Other:) _____		
Name: Denise Rogers		
Title: Compliance Manager		
Mailing Address: 1401 McKinney, Suite 1500		
City: Houston	State: TX	ZIP Code: 77010
Telephone No.: 832-203-6493	Fax No.: 832-203-6401	
E-mail Address: denise.rogers@texasgulfterminals.com		
All permit correspondence will be sent via electronic copies unless hard copies are specifically requested through regular mail. The company official must initial here if hard copy correspondence is requested. _____		
C. Technical Contact Name Information: (☐ Mr. ☐ Mrs. ☒ Ms. ☐ Other:) _____		
Name: Denise Rogers		
Title: Compliance Manager		
Company Name: Texas Gulf Terminals Inc		
Mailing Address: 1401 McKinney, Suite 1500		
City: Houston	State: TX	ZIP Code: 77010
Telephone No.: 832-203-6493	Fax No.: 832-203-6401	
E-mail Address: denise.rogers@texasgulfterminals.com		
D. Site Name: Texas Gulf Terminals Project		
E. Area Name/Type of Facility:	☒ Permanent ☐ Portable	
For portable units, please provide the serial number of the equipment being authorized below.		
Serial No:	Serial No:	
F. Principal Company Product or Business: Offshore Marine Terminal		
Principal Standard Industrial Classification Code (SIC): 4612		
Principal North American Industry Classification System (NAICS): 486910		
G. Projected Start of Construction Date: TBD		
Projected Start of Operation Date: TBD		

I. Applicant Information (continued)		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: Site is approximately 14 miles offshore the coast of Texas, Southeast of Corpus Christi.		
City/Town: N/A	County: N/A	ZIP Code: N/A
Latitude (nearest second): 27° 28' 42.6"	Longitude (nearest second): 97° 00' 48.43"	
I. Account Identification Number (leave blank if new site or facility):		
J. Core Data Form		
Is the Core Data Form (Form 10400) attached? If No, provide customer reference number and regulated entity number (complete K and L).		☒ YES ☐ NO
K. Customer Reference Number (CN):		
L. Regulated Entity Number (RN):		
II. General Information		
A. Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.		☐ YES ☒ NO
B. Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.		☐ YES ☒ NO
C. Number of New Jobs: N/A		
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:		
State Senator: N/A	District No.: N/A	
State Representative: N/A	District No.: N/A	
III. Type of Permit Action Requested		
A. Mark the appropriate box indicating what type of action is requested.		
☒ Initial	☐ Amendment	☐ Revision (30 TAC § 116.116(e)
☐ Change of Location		☐ Relocation
B. Permit Number (if existing):		
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)*		
☐ Construction ☐ Flexible ☐ Multiple Plant	☐ Nonattainment	☐ Plant-Wide Applicability Limit
☐ Prevention of Significant Deterioration (PSD)	☐ Hazardous Air Pollutant Major Source	
☐ PSD for greenhouse gases (GHGs)	☒ Other: Initial Title V Operating Permit_____	

III. Type of Permit Action Requested *(continued)*		
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC § 116.315(c).		☐ YES ☒ NO
E. Is this application for a change of location of previously permitted facilities?		☐ YES ☒ NO
If Yes, complete all parts of III.E.		
Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO," attach detailed information.		☐ YES ☐ NO
Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?		☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.		
List: N/A		
G. Are you permitting planned maintenance, startup, and shutdown emissions?		☐ YES ☒ NO
If Yes, attach information on any changes to emissions under this application as specified in VII and VIII.		
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability)		
Is this facility located at a site required to obtain a federal operating permit?		☒ YES ☐ NO ☐ To be determined
If Yes, list all associated permit number(s), attach pages as needed).		
Associated Permit No (s.):		
Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.		
☐ FOP Significant Revision	☐ FOP Minor	☐ Application for an FOP Revision
☐ Operational Flexibility/Off-Permit Notification		☐ Streamlined Revision for GOP
☒ To be Determined		☐ None

III. Type of Permit Action Requested *(continued)*	
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)***	
☐ GOP Issued ☐ GOP application/revision application submitted or under APD review	
☐ SOP Issued ☐ SOP application/revision application submitted or under APD review	
IV. Public Notice Applicability	
A. Is this a new permit application or a change of location application?	☒ YES ☐ NO
B. Is this application for a concrete batch plant? If Yes, complete all parts of V.D.	☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA § 112(g) permit, or exceedance of a PAL permit?	☐ YES ☒ NO
D. If this is an application for emissions of GHGs, select one of the following:	
☐ separate public notice (requires a separate application) ☒ consolidated public notice	
E. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☐ YES ☒ NO
If Yes, list the affected state(s) and/or Class I Area(s).	
List:	
F. Is this a state permit amendment application? If Yes, complete all parts of IV.F.	
Is there any change in character of emissions in this application?	☐ YES ☐ NO
Is there a new air contaminant in this application?	☐ YES ☐ NO
Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
List the total annual emission increases associated with the application ***(List all that apply and attach additional sheets as needed):***	
Volatile Organic Compounds (VOC):	
Sulfur Dioxide (SO_2):	
Carbon Monoxide (CO):	
Nitrogen Oxides (NO_x):	
Particulate Matter (PM):	
PM 10 microns or less (PM_{10}):	
PM 2.5 microns or less ($PM_{2.5}$):	
Lead (Pb):	
Hazardous Air Pollutants (HAPs):	
Other speciated air contaminants not listed above:	

V. Public Notice Information *(complete if applicable)*		
A. Responsible Person: (☐ Mr. ☐ Mrs. ☐ Ms. ☐ Other:) _____		
Name:		
Title:		
Company Name:		
Mailing Address:		
City:	State:	ZIP Code:
Telephone No.:	Fax No.:	
E-mail Address:		
B. Technical Contact: (☐ Mr. ☐ Mrs. ☐ Ms. ☐ Other:) ___		
Name:		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
Telephone No.:	Fax No.:	
E-mail Address:		
C. Name of the Public Place:		
Physical Address *(No P.O. Boxes)*:		
City:	County:	ZIP Code:
The public place has granted authorization to place the application for public viewing and copying.		☐ YES ☐ NO
The public place has internet access available for the public.		☐ YES ☐ NO
D. Concrete Batch Plants, PSD, and Nonattainment Permits		
County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable:		
Mailing Address:		
City:	State:	ZIP Code:

V. Public Notice Information *(complete if applicable)*		
D. Concrete Batch Plants, PSD, and Nonattainment Permits *(continued)*		
Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
Provide the name, mailing address of the chief executive for the location where the facility is or will be located.		
Chief Executive:		
Mailing Address:		
City:	State:	ZIP Code:
Provide the name, mailing address of the Indian Governing Body for the location where the facility is or will be located.		
Indian Governing Body:		
Mailing Address:		
City:	State:	ZIP Code:
Identify the Federal Land Manager(s) for the location where the facility is or will be located.		
Federal Land Manager(s):		
E. Bilingual Notice		
Is a bilingual program required by the Texas Education Code in the School District?		☐ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?		☐ YES ☐ NO
If Yes, list which languages are required by the bilingual program?		
VI. Small Business Classification *(Required)*		
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?		☐ YES ☒ NO
B. Is the site a major stationary source for federal air quality permitting?		☒ YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?		☒ YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?		☒ YES ☐ NO

VII. Technical Information

A. The following information must be submitted with your Form PI-1
(this is just a checklist to make sure you have included everything)

- ☒ Current Area Map
- ☒ Plot Plan
- ☒ Existing Authorizations
- ☒ Process Flow Diagram
- ☒ Process Description
- ☒ Maximum Emissions Data and Calculations
- ☒ Air Permit Application Tables
- ☒ Table 1(a) (Form 10153) entitled, Emission Point Summary
- ☐ Table 2 (Form 10155) entitled, Material Balance
- ☒ Other equipment, process or control device tables

B. Are any schools located within 3,000 feet of this facility?	☐ YES ☒ NO

C. Maximum Operating Schedule:

Hour(s): 24	Day(s): 365
Week(s): 52	Year(s):

Seasonal Operation? If Yes, please describe in the space provide below.	☐ YES ☒ NO
Hour(s):	Day(s):
Week(s):	Year(s):

D. Have the planned MSS emissions been previously submitted as part of an emissions inventory?	☐ YES ☒ NO

Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.

MSS Facility(s) or Activity	Year(s)

E. Does this application involve any air contaminants for which a disaster review is required?	☐ YES ☒ NO

If Yes, list which air contaminants require a disaster review.

VII.	**Technical Information *(continued)***	
F.	Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)?	☐ YES ☒ NO
G.	Are emissions of GHGs associated with this project subject to PSD?	☐ YES ☒ NO
If "yes," provide a list of all associated applications for this project:		
See attachments		
VIII.	**State Regulatory Requirements** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non-applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*	
A.	Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?	☒ YES ☐ NO
B.	Will emissions of significant air contaminants from the facility be measured?	☐ YES ☒ NO
C.	Is the Best Available Control Technology (BACT) demonstration attached?	☒ YES ☐ NO
D.	Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?	☒ YES ☐ NO
IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non-applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
A.	Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?	☐ YES ☒ NO
B.	Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?	☐ YES ☒ NO
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☐ YES ☒ NO
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA § 112(g)] requirements apply to this application?	☒ YES ☐ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	
Is the estimated capital cost of the project greater than $2 million dollars?		☒ YES ☐ NO
If Yes, submit the application under the seal of a Texas licensed P.E.		

XI. Permit Fee Information	
Check, Money Order, Transaction Number, ePay Voucher Number: N/A	
Fee Amount: $ N/A	
Paid online? N/A	☐ YES ☐ NO
Company name on check:	
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☐ YES ☐ NO ☒ N/A

XII. Delinquent Fees and Penalties

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

XIII. Signature

The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7; the Texas Health and Safety Code, Chapter 382, the Texas Clean Air Act (TCAA) the air quality rules of the Texas Commission on Environmental Quality; or any local governmental ordinance or resolution enacted pursuant to the TCAA. I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.

Name: Denise Rogers

Signature: Denise Rogers
Original Signature Required

Date: 6/26/2018

5.1. PROCESS DESCRIPTION

The proposed SPM buoy system will enable Very Large Crude Carriers (VLCCs) to be fully and completely loaded directly with crude oil/condensate from the SPM. The crude oil/condensate will be supplied to the SPM buoy system from the Onshore Storage Terminal Facility (OSTF), through a pipeline infrastructure, and to the SPM buoy system. Two (2) 30-inch-diameter pipelines will each be capable of 30,000 bph flow rate allowing an overall system crude oil/condensate delivery capacity of 60,000 bph to vessels moored at the proposed SPM buoy system. Vessels will be moored to the proposed SPM buoy system via mooring hawsers. Crude oil will be routed from subsea PLEM via two 24-inch ID flexible hoses to SPM buoy. Floating hoses will extend from the SPM buoy system to the moored vessel to allow for the loading of crude oil/condensate. The project will have a crude oil/condensate loading capacity of 60,000 bph and 192 million barrels per year. The project will be able to load up to 96 large vessels per year.

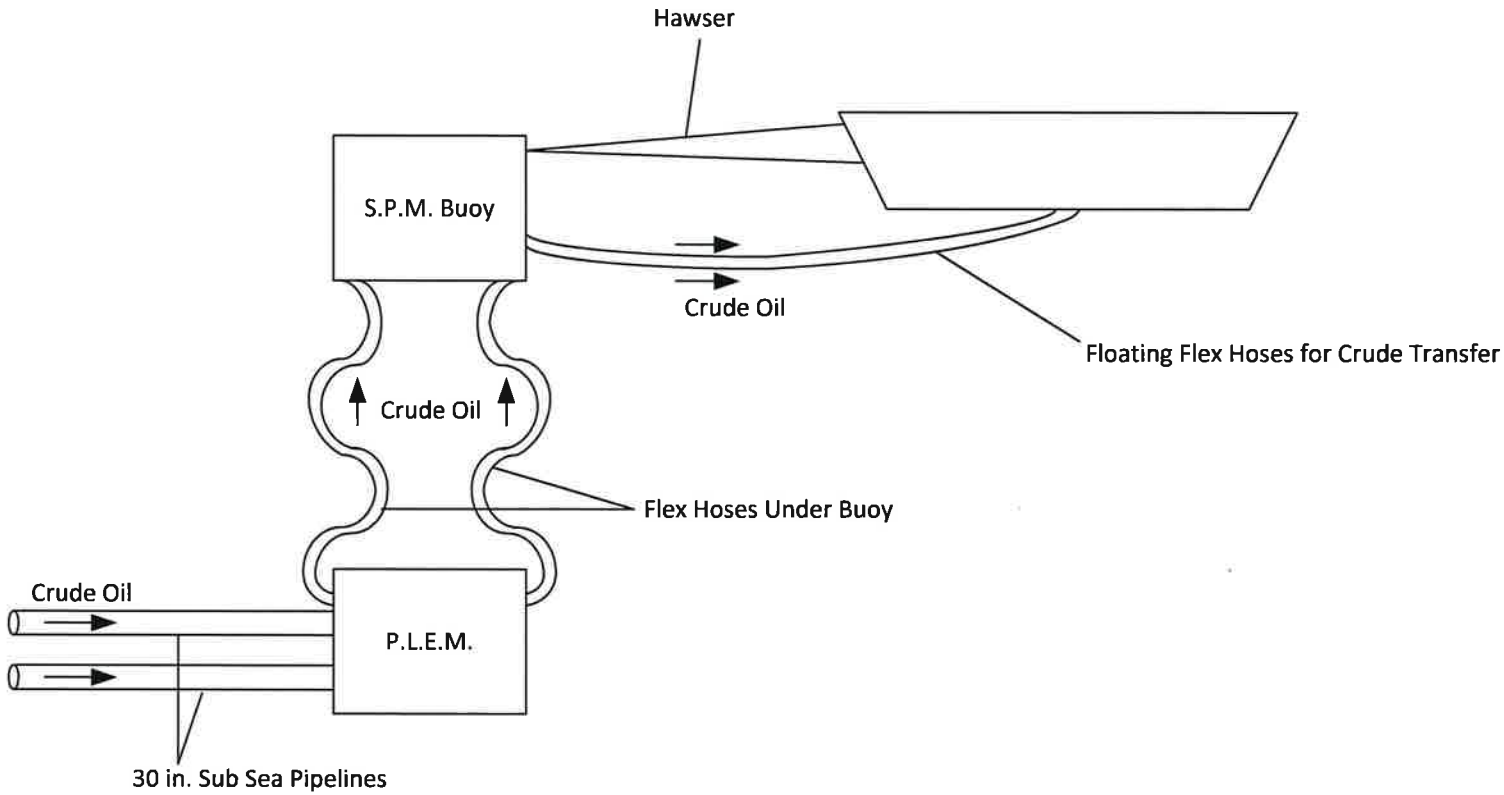
5.2. PROJECT DESCRIPTION

The proposed project includes 14.62 miles of two (2) new paralleling 30-inch diameter offshore pipelines and the DWP.

Offshore pipelines - The proposed project requires the ability to export multiple grades of crude oil/condensate. As such, the proposed offshore pipeline infrastructure will comprise a dual pipeline system to allow for the flushing of lines of one crude grade back to the Onshore Storage Terminal Facility (OSTF). Under normal operations, the OSTF will pump crude oil/condensate through both offshore pipelines to the PLEM and SPM buoy system for the loading of vessels moored at the DWP.

DWP - The proposed SPM buoy system will consist of a Pipeline End Manifold (PLEM) system, mooring hawsers, and floating hoses to allow for the loading of crude oil to vessels moored at the proposed SPM buoy system. The proposed SPM buoy system will be of the Catenary Anchor Leg Mooring (CALM) type permanently moored with a symmetrically arranged six-leg anchor chain system extending to pile anchors fixed on the seafloor. The proposed SPM buoy system will consist of inner and outer cylindrical shells subdivided into twelve equal-sized watertight radial compartments. A rotating table will be affixed to the SPM buoy and allow for the connection of moored vessels to the SPM buoy system via mooring hawsers. A series of floating hose strings equipped with marine break-away couplings will be utilized for the transfer of crude oil from the SPM buoy system to the moored vessel. Floating hoses will be equipped with strobe lights (Winkler Lights) at 15-foot intervals for detection at night and periods of low-light. The PLEM system that will serve as the connection point between subsea pipelines and the SPM buoy system through a series of 24-inch-diameter submarine hoses. The PLEM system would be a steel frame structure positioned directly beneath the proposed SPM buoy system and would be anchored directly to the seafloor with piles.

The only primary emissions involved in the proposed project are the VOC emissions resulting from the loading of crude oil/condensate from the SPM buoy system onto a VLCC.

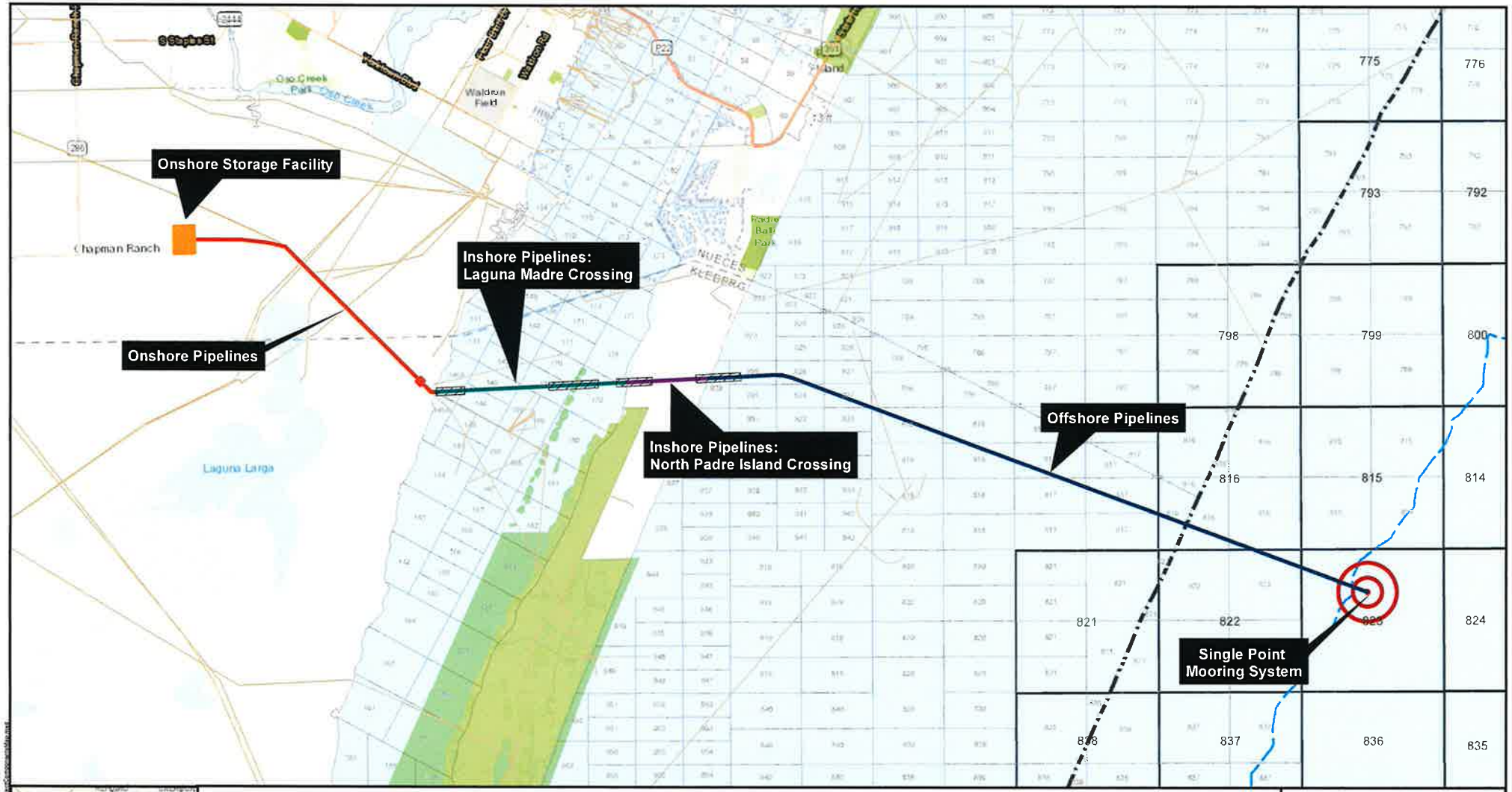


Texas Gulf Terminals Inc.

Process Flow Diagram

Trinity Consultants

Project 184403.0005
April 2018



Legend

- Onshore Storage Facility Property
- Pump Station
- HDD Pipeline Section
- Onshore Segment
- Inshore Laguna Madre Segment
- Inshore North Padre Island Segment
- Offshore Segment
- SPM System and Safety Zone
- Existing Pipelines (RRC)
- Parks, NWRs, WMAs
- 90ft Depth Contour
- Federal/State Line
- GLO Lease Tracts
- Federal Lease Blocks

N

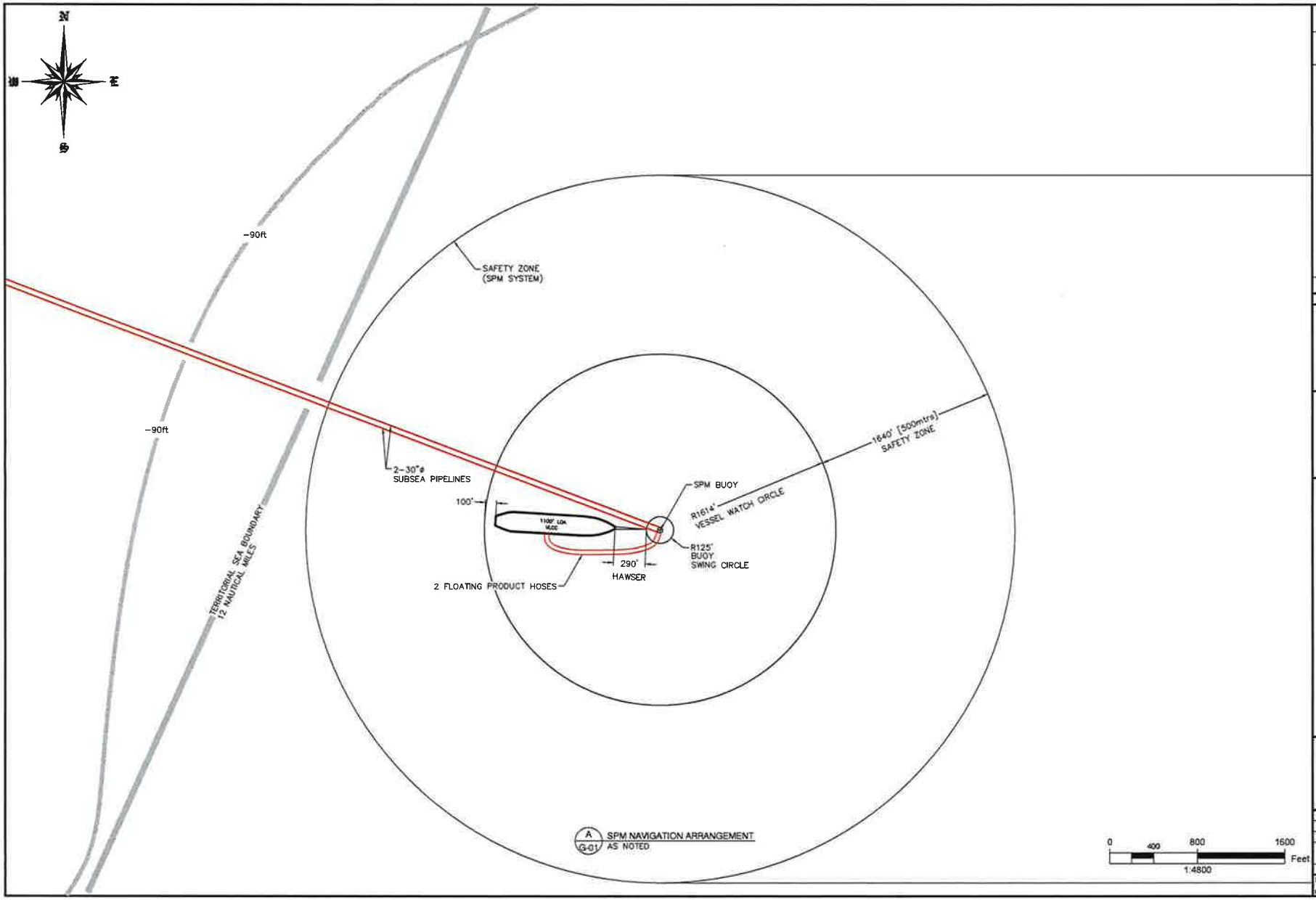
Coordinate System: NAD 1983 StatePlane
Texas South Central FIPS 4204 Feet
Projection: Lambert Conformal Conic
Datum: North American 1983
Units: Foot US

0 5,000 10,000 20,000 Feet

Project Component Overview Map
Texas Gulf Terminals Inc
Texas Gulf Terminals Project

Date: May 21, 2018
Prepared By: CG
Project: TGTI
1 inch = 10,000 feet

LOYD ENGINEERING, INC.



REV	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	-

ISSUED FOR REVIEW

TEXAS GULF TERMINALS INC.

TEXAS GULF TERMINALS PROJECT

SPM ARRANGEMENT DETAIL

LOYD ENGINEERING, INC.
HOUSTON, TEXAS USA
LICENSE NO. F-312540

DESIGN BY:	SL
DRAWN BY:	-
DATE:	MARCH 2018
SCALE:	AS NOTED @ 22"X34"
SHEET:	2 OF 2
DRAWING NO:	
REV. A	2

6.1. EMISSIONS SUMMARY

A summary of proposed emissions is shown in table below.

Table 6-1. Potential Emissions Summary

	NO_X (tpy)	CO (tpy)	VOC (tpy)	SO_2 (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	H_2S (tpy)	H_2SO_4 (tpy)
New Sources								
Loading	--	--	10,808	--	--	--	0.24	--
Fugitives	--	--	0.22	--	--	--	--	--
Total Project Increases:	--	--	10,808	--	--	--	0.24	--

6.2. INFORMATION FOR EMISSION CALCULATIONS

6.2.1. Marine Loading

Emissions from marine loading of crude oil/condensate are calculated based on TCEQ's Air Permit Technical Guidance for Chemical Sources: Loading Operations (October 2000) using the following equation from U.S. EPA's AP-42, Section 5.2:

$$L = 12.46 \times S \times P \times M/T$$

where:

L = Loading Loss (lb/10^3 gal of liquid loaded)
S = Saturation factor
P = True vapor pressure of liquid loaded (psia)
M = Molecular weight of vapors (lb/lb-mole)
T = Temperature of bulk liquid loaded (R)

A saturation factor of 0.2 is used for submerged loading using ships. A maximum true vapor pressure of 11 psia is used for crude oil/condensate loading.

6.3. POLLUTION CONTROL EQUIPMENT

TGTI proposes to use submerged loading and loading only onto ships which comply with VOC management plan requirements in MEPC.185(59) as control for VOC emissions. A detailed Best Available Control Technology (BACT) analysis is conducted and provided in the New Source Review (NSR) application.

Table 6-2 – Summary of Proposed BACT (VOC)

Emission Unit	Pollutant	BACT Determination	Proposed BACT Emission Limit	Averaging Period
SPM Buoy System	VOC	Submerged Loading and loading ships which comply with VOC management plan requirements in MEPC.185(59)	N/A	N/A

7.1. FEDERAL REQUIREMENTS

The proposed SPM buoy system will be located approximately 14 miles from the coast of Kleberg County. Due to unavailability of attainment/non-attainment information in project area offshore, TGTI proposes to use the attainment status of the nearest County onshore, which is Kleberg County. Kleberg County is considered in attainment or unclassified for all FNSR pollutants. Therefore, the project will not be subject to Non-attainment New Source Review (NNSR), and will only be subject to Prevention of Significant Deterioration (PSD) review if it is determined that emissions of criteria pollutants from the facility will trigger the major source threshold. A major stationary source is defined as either one of the sources identified in 40 CFR 51.166 and which has a PTE of 100 tons or more per year of any regulated pollutant, or any other stationary source which has a PTE of 250 tpy or more of a regulated pollutant. The proposed project is not on the list of 28 source categories listed in 40 CFR 51.166 which have a major source threshold of 100 tpy. Therefore, the proposed project will be subject to PSD if it is determined that emissions form the facility will exceed 250 tpy of any regulated pollutant.

The only FNSR pollutant from the proposed project will be VOC. Based on potential air emissions from the facility, the project will be subject to preconstruction review under the federal PSD regulations since potential VOC emissions will be greater than the 250 ton per year PSD major source threshold. TGTI has submitted an application covering the NSR air permit application requirements under separate cover. The major requirement have been summarized in the following sections.

Table 7-1. FNSR PSD Analysis Summary

	NO_X (tpy)	CO (tpy)	VOC (tpy)	SO_2 (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	H_2S (tpy)	H_2SO_4 (tpy)
New Sources								
Loading	--	--	10,808	--	--	--	0.24	--
Fugitives	--	--	0.22	--	--	--	--	--
Total Project Increases:	--	--	10,808	--	--	--	0.24	--
PSD Threshold	250	250	250	250	250	250	10	7
PSD Review Required	N/A	N/A	Yes	N/A	N/A	N/A	N/A	N/A

7.2. FEDERAL BACT

Based on the BACR analysis, TGTI has determined that submerged loading is BACT for the proposed SPM buoy system. Given that VRU and VCU are both technologically infeasible and there are no comparable sources in RBLC that show otherwise, TGTI proposes submerged loading as BACT. A detailed BACT analysis was provided under separate cover in the NSR application.

Table 7-2. – Summary of Proposed BACT (VOC)

Emission Unit	Pollutant	BACT Determination	Proposed BACT Emission Limit	Averaging Period
SPM Buoy System	VOC	Submerged Loading and loading ships which comply with VOC management plan requirements in MEPC.185(59)	N/A	N/A

7.3. AIR QUALITY MODELING AND OTHER IMPACT ANALYSES

While the NAAQS compliance demonstration and State Health Effects Review are being submitted under separate cover, the Additional Impacts Analysis is addressed below.

7.4. ADDITIONAL IMPACTS ANALYSIS

Due to the large distance of the Project's location from land areas, TGTI believes that the following impact analyses would not be applicable to the proposed project:

- Growth analysis
- Soils and vegetation analysis
- Visibility impairment analysis

Federal and TCEQ guidelines require that an air quality dispersion modeling analysis (including visibility analysis) be performed for each Class I area located within 100 km of a facility undergoing an installation/modification that exceeds PSD significant emission rates. Since the nearest Class I area is more than 500 km from the proposed SPM buoy system, a Class I area analysis is not required.

7.5. CASE-BY-CASE MACT ANALYSIS

TGTI developed a case-by-case MACT under section 112(g) of the CAA and 40 CFR 63, as referenced in 30 TAC Chapter 116, Subchapter E. The case-by-case application was developed because the SPM buoy system will be a major source of HAP emissions that is not regulated by an existing MACT standard. TGTI has concluded that submerged fill and loading of only ships which comply with VOC management plan requirements in MEPC.185(59) represents MACT for the proposed SPM buoy system since this is the control that is met by the best similar source and additional control beyond this is not feasible due to technical and safety constraints. Therefore, submerged fill and loading only ships which meet the VOC management plan requirements of MEPC.185(59) meets MACT under 112(g) for HAP emissions from the proposed SPM buoy system.

7.6. STATE REGULATORY REQUIREMENTS

7.6.1. General Application Requirements (30 TAC §116.111)

(1) a completed Form PI-1 General Application signed by an authorized representative of the applicant. All additional support information specified on the form must be provided before the application is complete;

A completed TCEQ Form PI-1 signed by an authorized representative and all additional supporting information as specified on the form are provided in this application.

(2) information which demonstrates that emissions from the facility, including any associated dockside vessel emissions, meet all of the following.

(2)(A) Protection of public health and welfare.

(2)(A)(i) The emissions from the proposed facility will comply with all rules and regulations of the commission and with the intent of the Texas Clean Air Act (TCAA), including protection of the health and property of the public.

TGTI will comply with all rule and regulations of the commission and with the intent of the Texas Clean Air Act (TCAA), including protection of the health and property of the public. A review of potentially applicable rules is provided below.

Chapter 101 – General Rules: The proposed SPM buoy system will be operated in accordance with all applicable requirements in Chapter 101. Specifically, the proposed SPM buoy system will be operated in accordance with the Chapter 101 General Rules relating to circumvention, nuisance, traffic hazard, notification and recordkeeping requirements for emission events and for startup/shutdown/maintenance, sampling and sampling port procedures, emissions inventory requirements, compliance with Environmental Protection Agency Standards, the National Primary and Secondary Ambient Air Quality Standards, inspection fees, emissions fees, and all other applicable General Rules.

Chapter 111 - Control of Air Pollution from Visible Emissions and Particulate Matter: The proposed SPM buoy system will comply with all applicable requirements in Chapter 111.

Chapter 112 – Control of Air Pollution from Sulfur Compounds: The proposed SPM buoy system will comply with all applicable emission limitations, allowable emission rates, monitoring, reporting, and recordkeeping requirements of 30 TAC Chapter 112.

Chapter 113 – Control of Air Pollution from Toxic Materials: Chapter 113 regulates the emission of radionuclides (40 CFR Part 61, Subpart R), municipal solid waste landfills, hospital/medical/infectious waste incinerators, and hazardous air pollutants for source categories (40 CFR Part 63). There will be no emissions of radionuclides from the proposed SPM buoy system. The proposed SPM buoy system is not a municipal solid waste landfill and does not have a hospital/medical/ infectious waste incinerator. Therefore, these sections of the regulation do not apply. Emissions from hazardous air pollutants are regulated under the MACT program, addressed in the discussion of compliance with Chapter 122 in item (2)(F) below.

Chapter 114 – Control of Air Pollution from Motor Vehicles: No motor vehicles will operate at the proposed SPM buoy system. Therefore, the provisions of Chapter 114 do not apply.

Chapter 115 – Control of Air Pollution from Volatile Organic Compounds (VOC): The proposed SPM buoy system will comply with all applicable requirements in Chapter 115 for loading operations.

Chapter 117 – Control of Air Pollution from Nitrogen Compounds: The proposed SPM buoy system will not be located in a county that is subject to the requirements of Chapter 117.

Chapter 118 – Control of Air Pollution Episodes: The proposed SPM buoy system will not be located in a county that is subject to the requirements of Chapter 118.

Chapter 122 – Federal Operating Permits: The proposed SPM buoy system will be a major source of regulated pollutants as defined in 30 TAC Chapter 122. TGTI will submit a Title V Permit application per the requirements of 40 CFR Part 71 per EPA Region 6 request.

(2)(B) Measurement of emissions. The proposed facility will have provisions for measuring the emission of significant air contaminants as determined by the executive director. This may include the installation of sampling ports on exhaust stacks and construction of sampling platforms in accordance with guidelines in the "Texas Commission on Environmental Quality Sampling Procedures Manual."

Emissions from any source addressed in the application will be sampled upon request of the Executive Director of the TCEQ, and sampling ports and sampling platforms will be installed as needed.

(2)(C) Best available control technology (BACT) must be evaluated for and applied to all facilities subject to the TCAA. Prior to evaluation of BACT under the TCAA, all facilities with pollutants subject to regulation under Title I Part C of the Federal Clean Air Act (FCAA) shall evaluate and apply BACT as defined in §116.160(c)(1)(A) of this title (relating to Prevention of Significant Deterioration Requirements).

This permit application demonstrates that the proposed SPM buoy system will utilize BACT for all emissions sources being proposed as part of this permit application.

(2)(D) New Source Performance Standards (NSPS). The emissions from the proposed facility will meet the requirements of any applicable NSPS as listed under 40 Code of Federal Regulations (CFR) Part 60, promulgated by the United States Environmental Protection Agency (EPA) under FCAA, §111, as amended.

The proposed SPM buoy system will not be subject to any NSPS under 40 CFR Part 60.

(2)(E) National Emission Standards for Hazardous Air Pollutants (NESHAP). The emissions from the proposed facility will meet the requirements of any applicable NESHAP, as listed under 40 CFR Part 61, promulgated by EPA under FCAA, §112, as amended.
The proposed SPM buoy system will not be subject to NESHAPs under 40 CFR Parts 61.

(2)(F) NESHAP for source categories. The emissions from the proposed facility will meet the requirements of any applicable maximum achievable control technology standard as listed under 40 CFR Part 63, promulgated by the EPA under FCAA, §112 or as listed under Chapter 113, Subchapter C of this title (relating to National Emissions Standards for Hazardous Air Pollutants for Source Categories (FCAA §112, 40 CFR Part 63)).

TGTI has submitted a case-by-case MACT applicability assessment to demonstrate that the maximum achievable control technology is being applied to the proposed SPM buoy system.

(2)(G) Performance demonstration. The proposed facility will achieve the performance specified in the permit application. The applicant may be required to submit additional engineering data after a permit has been issued in order to demonstrate further that the proposed facility will achieve the performance specified in the permit application. In addition, dispersion modeling, monitoring, or stack testing may be required.

The proposed SPM buoy system will achieve the performance represented in this permit application.

(2)(H) Nonattainment review. If the proposed facility is located in a nonattainment area, it shall comply with all applicable requirements in this chapter concerning nonattainment review.

As discussed earlier in this section, the proposed SPM buoy system is not located in a nonattainment county, NNSR is not applicable.

(2)(I) Prevention of Significant Deterioration (PSD) review.
(2)(I)(i) If the proposed facility is located in an attainment area, it shall comply with all applicable requirements in this chapter concerning PSD review.

(2)(I)(ii) If the proposed facility or modification meets or exceeds the applicable greenhouse gases thresholds defined in §116.164 of this title (relating to Prevention of Significant Deterioration Applicability for Greenhouse Gases Sources) then it shall comply with all applicable requirements in this chapter concerning PSD review for sources of greenhouse gases.

The proposed SPM buoy system is a new major source with respect to the PSD permitting program due to potential emissions of VOCs; therefore, TGTI has submitted and NSR air permit application under separate cover in order to comply with the PSD new source review requirements.

(2)(J) Air dispersion modeling. Computerized air dispersion modeling may be required by the executive director to determine air quality impacts from a proposed new facility or source modification. In determining whether to issue, or in conducting a review of, a permit application for a shipbuilding or ship repair operation, the commission will not require and may not consider air dispersion modeling results predicting ambient concentrations of non-criteria air contaminants over coastal waters of the state. The commission shall determine compliance with non-criteria ambient air contaminant standards and guidelines at land-based off-property locations.

TGTI has conducted air dispersion modeling to demonstrate the ambient air impacts of the proposed SPM buoy system. They have been submitted under separate cover.

(2)(K) Hazardous air pollutants. Affected sources (as defined in §116.15(1) of this title (relating to Section 112(g) Definitions)) for hazardous air pollutants shall comply with all applicable requirements under Subchapter E of this chapter (relating to Hazardous Air Pollutants: Regulations Governing Constructed or Reconstructed Major Sources (FCAA, §112(g), 40 CFR Part 63)).

TGTI will comply will comply with all applicable requirements under Subchapter E of this chapter as related to Section 112(g).

(2)(L) Mass cap and trade allowances. If subject to Chapter 101, Subchapter H, Division 3, of this title (relating to Mass Emissions Cap and Trade Program), the proposed facility, group of facilities, or account must obtain allowances to operate.

This regulation refers to Chapter 101, Subchapter H, Division 3, which applies to facilities in the Houston-Galveston-Brazoria (HGB) ozone nonattainment area. The proposed SPM buoy system will not located in the HGB ozone nonattainment area. Therefore, the provisions of this regulation do not apply.

(b) In order to be granted a permit, amendment, or special permit amendment, the owner or operator must comply with the following notice requirements.

(1) Applications declared administratively complete before September 1, 1999, are subject to the requirements of Division 3 of this subchapter (relating to Public Notification and Comment Procedures).

Not applicable. The permit application will be sent to the TCEQ in 2018.

(2) Applications declared administratively complete on or after September 1, 1999, are subject to the requirements of Chapter 39 of this title (relating to Public Notice) and Chapter 55 of this title (relating to Request for Reconsideration and Contested Case Hearings; Public Comment). Upon request by the owner or operator of a facility which previously has received a permit or special permit from the commission, the executive director or designated representative may exempt the relocation of such facility from the provisions in Chapter 39 of this title if there is no indication that the operation of the facility at the proposed new location will significantly affect ambient air quality and no indication that operation of the facility at the proposed new location will cause a condition of air pollution.

TGTI will comply with all applicable notice requirements under Chapter 39 and Chapter 55 associated with this permit application.

8.1. PERMIT FEE

Based on the requirements 40 CFR 71.9 Each permit application requires an application fee that is based upon the actual emissions from the project. The total fee is estimated in 40 CFR Part 71 form provided in Section 4 of this Title V application. Since this application is being submitted before the proposed project has begun operation, the required permit application fee is $0.

9. CERTIFICATION OF COMPLIANCE

The certification of compliance is included in the 40 CFR Part 71 form provided in Section 4 of this application

APPENIDX F: TCEQ AUTHORIZATIONS FOR ONSHORE FACILITIES

Tank Farm

- NRSP Application
- NRSP Approval Documentation
- PBR 106.511 Documentation for Emergency Generator

Booster Station

- NRSP Application
- NRSP Approval Documentation

Valve Station

- De Minimis Documentation

Tank Farm
NRSP Application

TEXAS GULF TERMINALS INC.
5 HOUSTON CENTER, 1401 MCKINNEY, SUITE 1500, HOUSTON, TX 77010, USA TEL: +(1) 832 203 6400 - FAX: +(1) 832 203 6401

June 22, 2018

Air Permits Initial Review Team (APIRT)
Texas Commission on Environmental Quality
Building C, Third Floor, Room 300 W, Mail Code 161
12100 Park 35 Circle
Austin, TX 78753

RE: ***Air Quality Standard Permit for Oil and Gas Handling and Production Facilities***
Texas Gulf Terminals Inc. – TGTI Onshore Terminal – Nueces County
Registration No. 151335
TCEQ Customer Reference No. (CN) CN605490085
TCEQ Regulated Entity Reference No. (RN) RN110317666

To Whom It May Concern,

Texas Gulf Terminals, Inc. (TGTI) submitted a Non-Rule Standard Permit (NRSP) registration in April 2018 to authorize the construction of a crude oil/condensate terminal known as the TGTI Onshore Terminal on the mainland near the Laguna Madre shore line in Kleberg County, Texas. The NRSP registration was approved on April 9, 2018 with the assigned Registration No. 151335. With this registration, TGTI is proposing to authorize the following changes to equipment and operations at the onshore terminal under the Non-Rule Standard Permit.

- Add Oil Water Separator and associated Fugitives;
- An emergency generator is authorized under PBR 106.511; therefore it is not included in this Non-rule Standard Permit;
- Update the physical location of the terminal, and
- Reduce the maximum filling rate of slop oil tank (EPN TK-SLOP) from 25,000 bbl/hr to 23,000 bbl/hr.

Please note that TGTI submitted the pre-construction notification (Notification Number 244724, Project No. 151335) for this project on June 22, 2018 via STEERS. The $900 application fee [$850 NRSP fee and $50 New Project Notification (NPN) fee] has been submitted electronically through the TCEQ STEERS system.

If you have any questions or comments regarding this submittal, please do not hesitate to contact me directly at 832-203-6493.

Sincerely,

Denise Rogers

Denise Rogers
Environmental Compliance Manager

Enclosure

cc: TCEQ Region 14, Corpus Christi
Mr. Brian Burdorf, Trinity Consultants, Inc.

TCEQ NON-RULE STANDARD PERMIT AMENDMENT REGISTRATION

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
Nueces County, Texas

Prepared By:

TRINITY CONSULTANTS
1800 West Loop South
Suite 1000
Houston, TX 77027
(713) 552-1371

June 2018

Project 174403.0035

Trinity Consultants

Environmental solutions delivered uncommonly well

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1. EXECUTIVE SUMMARY

Texas Gulf Terminals, Inc. (TGTI) submitted a Non-Rule Standard Permit (NRSP) registration in April 2018 to authorize the construction of a crude oil/condensate terminal known as the TGTI Onshore Terminal on the mainland near the Laguna Madre shore line in Kleberg County, Texas. TGTI has been assigned Texas Commission on Environmental Quality (TCEQ) Customer Reference Number (No.) (CN) CN605490085 and a TCEQ Regulated Entity No. (RN) RN110317666. The New Project Notification (NPN) has been assigned the Registration Number 151335.

With this registration, TGTI is proposing to authorize the following changes to equipment and operations at the onshore terminal under the Non-Rule Standard Permit:

- Add Oil Water Separator and associated Fugitives;
- An emergency generator is authorized under PBR 106.511; therefore it is not included in this Non-rule Standard Permit;
- Update the physical location of the terminal, and
- Reduce the maximum filling rate of slop oil tank (EPN TK-SLOP) from 25,000 bbl/hr to 23,000 bbl/hr.

TGTI submitted the initial application (Notification Number 151335, Project No. 284021) for this project on April 09, 2018 via STEERS and received TCEQ approval on the same date. TGTI is submitting this Standard Permit revision to authorize additional equipment and change in location of the TGTI Onshore Terminal. This registration demonstrates that the site complies with the Non-Rule Standard Permit requirements and therefore, may be authorized to operate under the specified Standard Permit provisions.

The new location proposed for the site will be in Nueces County (current permit representation location is in Kleberg county) is currently classified as an attainment or unclassified area for all criteria pollutants.[1] The proposed TGTI Onshore Terminal will be a minor source with respect to Prevention of Significant Deterioration (PSD) and the Federal Operating Permit (Title V) programs. Although the proposed TGTI Onshore Terminal is located outside of the Barnett Shale Counties, Texas Gulf Terminals is voluntarily proposing to comply with the requirements of the Non-Rule Standard Permit (NRSP).

This registration includes the supporting documentation for the proposed equipment and operations at the TGTI Onshore Terminal, including an area map, plot plan, process description, process flow diagram (PFD), core data form, emissions data, impacts assessment, profession engineer seal, and review of potentially applicable regulatory requirements.

[1] The United States Environmental Protection Agency (U.S.EPA) Green Book. Source: https://www3.epa.gov/airquality/greenbook/ancl.html#TX. Accessed in November 2017.

2. PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

The proposed TGTI Onshore Terminal is a crude oil/condensate storage terminal. The TGTI Onshore Terminal storage tanks handle sweet crude oil/condensate with a maximum True Vapor Pressure (TVP) of 11 psia. The site will receive these products via up to four (4) bi-directional pipelines (inbound and outbound). Two (2) outbound pipelines will also be utilized. The products will be stored in internal floating roof (IFR) tanks. The proposed terminal will store the products within twelve (12) IFR tanks (EPNs TK-501, TK-502, TK-503, TK-504, TK-505, TK-506, TK-507, TK-508, TK-509, TK-510, TK-511 and TK-512) each with a storage volume of 500,000 bbl. A 250,000 bbl internal floating roof tank will be used to store either Slop Oil or the crude/condensate product. Each tank is represented with a maximum of 110 turnovers in a given year.

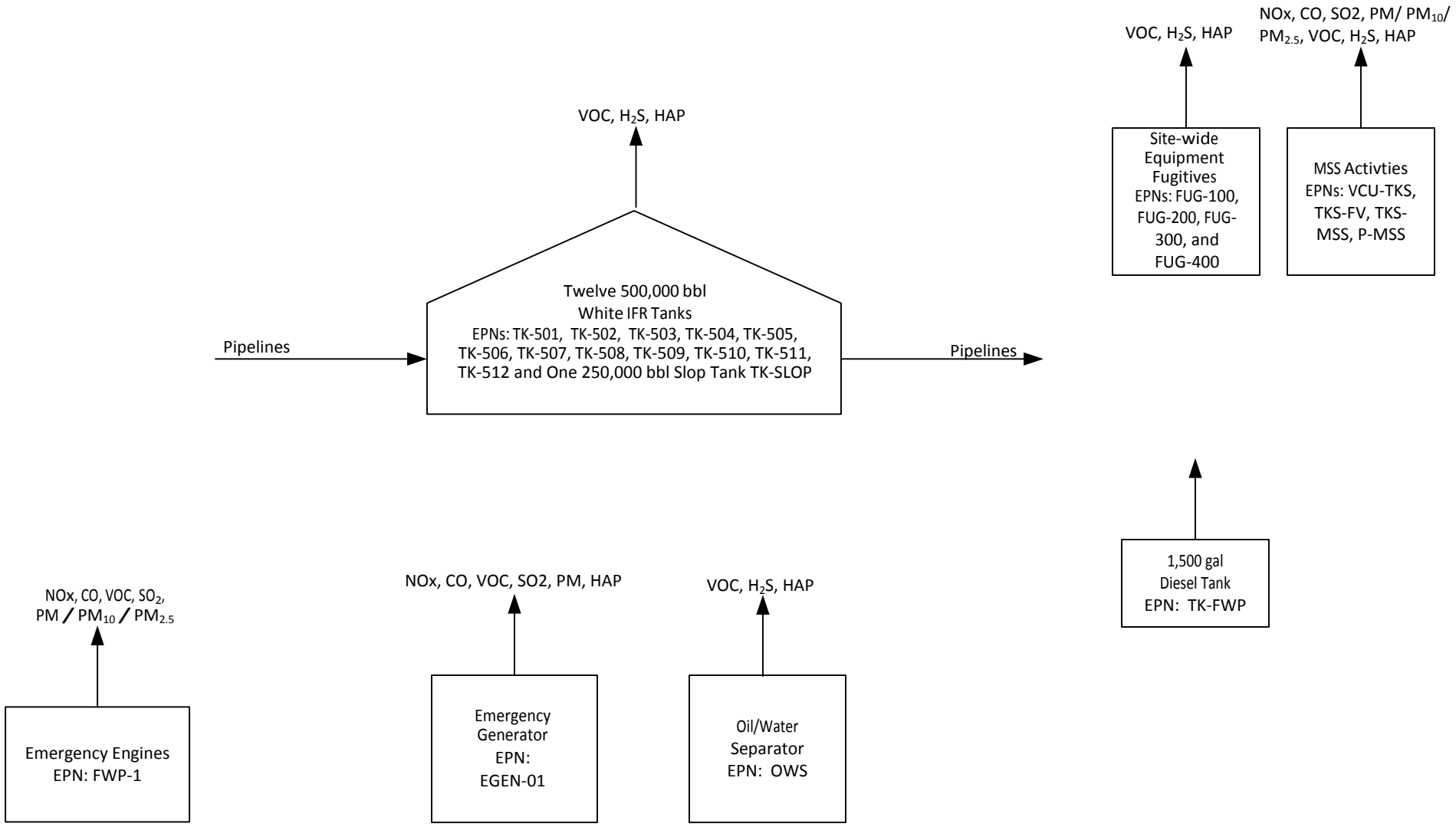
Fugitive emissions (EPNs FUG-100, FUG-200, FUG-300, and FUG-400) are emitted from piping connections and components throughout the TGTI Onshore Terminal, which are accounted for based on the estimated number of components to be installed. The terminal will also include one (1) emergency firewater pump (EPN FWP-1), (1) emergency generator (EPN EGEN-01)[2], one (1) diesel tank (EPN TK-FWP) and one oil-water separator (EPN OWS).

Planned periodic maintenance is performed on the proposed storage tanks at the site. The TGTI Onshore Terminal will include a vapor combustion unit (VCU) to combust emissions from standing idle, degassing and refilling maintenance activities (EPN VCU-TKS) and a carbon control unit (EPN TKS-MSS) to control sludge removal and vacuum truck venting activities. The VCU will operate using pipeline quality natural gas fuel. Tank MSS activities as associated with forced ventilation (EPN TKS-FV) will be vented directly to the atmosphere.

Planned pipeline MSS activities will also be performed at the site and will include activities such as pipeline pigging. All piping MSS emissions will be vented directly to the atmosphere (EPN P-MSS).

A process flow diagram is included at the end of this section for reference.

[2] The emergency generator is authorized under PBR 106.511; therefore it is not included in this Non-rule Standard Permit application.



Texas Gulf Terminals Inc.

Texas Gulf Terminals Inc. Onshore Terminal
Process Flow Diagram

Trinity Consultants

June 2018

3. EMISSIONS CALCULATION METHODOLOGY

This section describes the emissions calculation methodologies used to calculate emissions from the sources at the TGTI Onshore Terminal. The sources at the TGTI Onshore Terminal are expected to generate emissions of nitrogen oxides (NO_X), carbon monoxide (CO), sulfur dioxide (SO_2), hydrogen sulfide (H_2S), volatile organic compounds (VOCs), particulate matter (PM), including PM with an aerodynamic diameter of 10 microns or less (PM_{10}), PM with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$), and hazardous air pollutants (HAPs), specifically benzene. Greenhouse gas (GHG) emissions are not addressed within this registration because the project does not trigger PSD permitting for any criteria pollutant.[3] A summary of emissions proposed in this application is provided at the end of this section. Detailed emission calculations for this registration are included in Appendix B.

3.1. STORAGE TANKS

Emissions from storage tanks include VOC, H_2S, and benzene. Annual emissions from the proposed IFR storage tanks and horizontal diesel tank were calculated using TANKS 4.0.9d. Table 3-1 below lists out the maximum proposed throughputs for each of the storage tanks that were used in the corresponding TANKS 4.09d runs.

Table 3-1. Storage Tanks Located at the TGTI Onshore Terminal

EPN	Tank Contents	Tank Size (bbl)	Maximum Fill/Withdrawal Rate (bbl/hr)	Throughput (bbl/year)	Maximum and Average True Vapor Pressure (TVP) (psia)
TK-501	Sweet Crude Oil/Condensate Tank	500,000	60,000	55,000,000	11.00
TK-502	Sweet Crude Oil/Condensate Tank	500,000	60,000	55,000,000	11.00
TK-503	Sweet Crude Oil/Condensate Tank	500,000	60,000	55,000,000	11.00
TK-504	Sweet Crude Oil/Condensate Tank	500,000	60,000	55,000,000	11.00
TK-505	Sweet Crude Oil/Condensate Tank	500,000	60,000	55,000,000	11.00
TK-506	Sweet Crude Oil/Condensate Tank	500,000	60,000	55,000,000	11.00
TK-507	Sweet Crude Oil/Condensate Tank	500,000	60,000	55,000,000	11.00
TK-508	Sweet Crude Oil/Condensate Tank	500,000	60,000	55,000,000	11.00
TK-509	Sweet Crude Oil/Condensate Tank	500,000	60,000	55000,000	11.00
TK-510	Sweet Crude Oil/Condensate Tank	500,000	60,000	55,000,000	11.00
TK-511	Sweet Crude Oil/Condensate Tank	500,000	60,000	55,000,000	11.00
TK-512	Sweet Crude Oil/Condensate Tank	500,000	60,000	55,000,000	11.00
TK-SLOP	Slop Oil Storage Tank	250,000	23,000	27,500,000	11.00
TK-FWP	Diesel Fuel Storage Tank	1,500 (gal)	1,500 (gal)	1,200 (gal)	--

The material resulting in worst-case emissions between sweet crude oil and condensate is chosen to represent the hourly and annual emissions for each tank. The hourly and annual withdrawal and standing losses for the IFR tanks were calculated using the U.S. Environmental Protection Agency (EPA) TANKS 4.09d program. The

[3] Per June 23, 2014 Supreme Court ruling, a site cannot be considered major based solely on GHG emissions. If a site is an existing major source, then GHG emissions may undergo PSD review.

hourly breathing losses from these tanks are based on the annual emissions generated from U.S. EPA TANKS 4.09d averaged out over the month.

It is estimated that each sweet crude oil/condensate tank will have a maximum of 110 turnovers in a given year. Texas Gulf Terminals conservatively estimated the maximum and average Total Vapor Pressure (TVP) of the tank content to be 11 psia.

The sum of the withdrawal and standing losses were used to represent the worst-case VOC emissions from each tank. The hourly and annual benzene emissions are conservatively based on 1.5% benzene in sweet crude oil/condensate. As the tanks will store sweet crude, the maximum hourly and annual H_2S emissions are based on H_2S vapor fraction of 24 ppmv.

The short-term emissions associated with the diesel horizontal storage tank were calculated in accordance with the TCEQ Guidance Document on *Estimating Short Term Emission Rates from Tanks* (APDG 6250v1, Revised February 2018) as outlined below.

$$L_{MAX} = \frac{M_V \times P_{VA}}{R \times T} \times FR_M$$

Where:

L_{MAX}	=	Maximum short term emission rate, lbs/hour
M_V	=	Vapor molecular weight, lb/lb-mole
P_{VA}	=	Vapor pressure at worst case temperature, psia
FR_M	=	Maximum filling rate, gal/hr
R	=	Ideal gas constant, 80.273 (psia x gal)/(lbmol x °R)
T	=	Worst case liquid surface temperature, °95

Per TCEQ guidance, the worst case liquid surface temperature is either 95°F or the actual temperature, whichever is higher.

Annual emissions associated with the diesel storage tank were calculated using the U.S. Environmental Protection Agency (EPA) TANKS 4.09d program.

A copy of the TANKS 4.09d output is provided in Appendix B. A summary of the emissions from the tanks are provided in the table below:

Table 3-2. Summary of Tank Emissions at the TGTI Onshore Terminal

EPN	Description	Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
TK-501	IFR Tank 501	VOC	11.06	6.88
		H_2S	<0.01	<0.01
		Benzene	0.16	0.09
TK-502	IFR Tank 502	VOC	11.06	6.88
		H_2S	<0.01	<0.01
		Benzene	0.16	0.09
TK-503	IFR Tank 503	VOC	11.06	6.88
		H_2S	<0.01	<0.01
		Benzene	0.16	0.09
TK-504	IFR Tank 504	VOC	11.06	6.88

EPN	Description	Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
		H_2S	<0.01	<0.01
		Benzene	0.16	0.09
TK-505	IFR Tank 505	VOC	11.06	6.88
		H_2S	<0.01	<0.01
		Benzene	0.16	0.09
TK-506	IFR Tank 506	VOC	11.06	6.88
		H_2S	<0.01	<0.01
		Benzene	0.16	0.09
TK-507	IFR Tank 507	VOC	11.06	6.88
		H_2S	<0.01	<0.01
		Benzene	0.16	0.09
TK-508	IFR Tank 508	VOC	11.06	6.88
		H_2S	<0.01	<0.01
		Benzene	0.16	0.09
TK-509	IFR Tank 509	VOC	11.06	6.88
		H_2S	<0.01	<0.01
		Benzene	0.16	0.09
TK-510	IFR Tank 510	VOC	11.06	6.88
		H_2S	<0.01	<0.01
		Benzene	0.16	0.09
TK-511	IFR Tank 511	VOC	11.06	6.88
		H_2S	<0.01	<0.01
		Benzene	0.16	0.09
TK-512	IFR Tank 512	VOC	11.06	6.88
		H_2S	<0.01	<0.01
		Benzene	0.16	0.09
TK-SLOP	IFR Slop Tank	VOC	7.60	5.19
		H_2S	<0.01	<0.01
		Benzene	0.11	0.07
TK-FWP	Firewater Pump Diesel Tank	VOC	0.05	<0.01

3.2. FUGITIVE EMISSIONS FROM PIPING COMPONENTS

Process fugitive emissions result from leaking components (EPNs FUG-100, FUG-200, FUG-300, and FUG-400) such as valves, flanges, and pumps. Emissions of process fugitives are estimated using a representative component count and the corresponding oil and gas production emission factors provided in the EPA's "Protocol for Equipment Leak Emission Estimates" document, as referenced in TCEQ's Equipment Leak Fugitives guidance document.[4,5] Based on the liquids analysis, the components are assumed to be in light oil service, and are conservatively assumed to be 100% VOC.

Texas Gulf Terminals will conduct the Audio, Visual, and Olfactory (AVO) walk-through inspections as required by the use of these factors. Additionally, Texas Gulf Terminals will execute leak detection and repair (LDAR)

[4] U.S. EPA. Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017). November 1995.

[5] TCEQ. Industrial Emissions Assessment Section, Emissions Factors for Equipment Leak Fugitive Components, RG-360A, January 2008.

program meeting the requirements of the TCEQ's 28M program. A summary of the emissions from the fugitives are provided in the in the table below:

Table 3-3. Summary of Fugitive Emissions at the TGTI Onshore Terminal

EPN	Description	Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
FUG-100	Tanks & Vapor Combustion Unit Fugitives	VOC	0.63	2.75
		H_2S	<0.01	<0.01
		Benzene	<0.01	0.01
FUG-200	Manifold Fugitives	VOC	0.54	2.34
		H_2S	<0.01	<0.01
		Benzene	<0.01	0.01
FUG-300	Meter Skids Fugitives	VOC	0.24	1.03
		H_2S	<0.01	<0.01
		Benzene	<0.01	<0.01
FUG-400	Fugitives at OWS	VOC	0.01	0.05
		H_2S	<0.01	<0.01
		Benzene	<0.01	<0.01

3.3. FIREWATER PUMP

Emissions from the diesel Firewater Pump Engine (EPN FWP-01) result from the combustion of ultra-low sulfur diesel. Hourly emission rates of NO_X, CO, PM, PM_{10}, $PM_{2.5}$, VOC, and SO_2 are based on 40 CFR Part 60 Subpart IIII, Table 4 Emission Standards for Stationary Fire Pump Engines for engines greater than 750 hp with model year after 2008. The annual emission rate is based on maximum annual operation of 100 hours per year. A summary of emissions from the firewater pump are listed in the table below.

Table 3-4. Summary of Firewater Pump Emissions at the TGTI Onshore Terminal

EPN	Description	Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
FWP-01	Firewater Pump Engine	VOC	0.39	0.02
		CO	7.45	0.37
		SO_2	0.01	<0.01
		NO_X	13.36	0.67
		PM/ PM_{10}/ $PM_{2.5}$	0.43	0.02

3.4. MAINTENANCE, STARTUP & SHUTDOWN EMISSIONS

MSS activities are necessary and are performed periodically to ensure that the TGTI Onshore Terminal will operate in a manner that is safe, efficient, and environmentally sound. MSS activities are performed to the IFR product storage tanks and the pipelines, as necessary.

3.4.1. Tank Cleaning Operations

MSS emissions associated with the IFR storage tanks consist of tank standing idle losses, tank degassing, tank refilling/roof refloating, tank forced ventilation, as well as sludge removal and vacuum truck venting activities. All emission calculations for the storage tanks are based on the physical tank parameters and the physical properties of the materials stored. The calculations have conservatively assumed that the tanks have a full liquid heel. Hourly and annual emissions from tank cleanings are based on worst-case emissions between sweet crude oil and condensate.

Only one tank MSS activity will generally occur in any given hour and a maximum of four tanks can undergo MSS in a given year. Emissions from Standing Idle, Degassing, Forced Ventiation, and Refilling Activities are routed to the Vapor Combustion Unit (EPN VCU-TKS). The hourly emissions are based on the maximum emissions from any single MSS activity. Emissions from Sludge Removal and Vacuum Truck Venting activities are routed to carbon control (EPN TKS-MSS).

Emissions from the VCU will consist of emissions from combustion of sweet crude oil/condensate product vapors. Sweet crude oil/condensate emissions result from standing idle, degassing, and refilling activities. The NO_X and CO emissions from the VCU are based on 0.10 pound per million British thermal unit (lb/MMBtu) and 0.20 lb/MMBtu, respectively. NO_X and CO emissions from the combustion of the vapors generated by the MSS activities are calculated based on the product vapor streams routed to the vapor combustion unit. $PM/PM_{10}/PM_{2.5}$ emissions are based on the maximum hourly and annual flowrate to the VCU and the pound per million standard cubic feet (lb/MMscf) calculated using the heating value of sweet crude oil/condensate. H_2S and SO_2 emissions are calculated assuming sweet crude oil/condensate and a H_2S destruction efficiency of 99%. SO_2 emissions assume a 100% conversion from H_2S during combustion. Benzene emissions are calculated assuming 1.5% benzene in sweet crude oil/condensate vapors.

All MSS activities are calculated per TCEQ MSS Guidance, which references AP-42 Chapter 7.1, Organic Liquid Storage Tanks, American Petroleum Institute (API) Technical Report 2567 titled "*Evaporative Loss from Storage Tank Floating Roof Landings*", and API Technical Report 2568 titled "*Evaporative Loss from the Cleaning of Storage Tanks*".[6,7,8,9] The specific MSS activity emission calculation methodologies are described in the sections below.

3.4.1.1. Standing Idle Losses

Standing idle losses are calculated using TCEQ's MSS Guidance (AP-42 Chapter 7.1 and API 2568). Standing idle losses occur at two different times: 1) between initial degassing and subsequent maintenance and 2) after tank withdrawal is completed and before clean-out. Since these tank idling activities will not occur at the same time, the scenario that yields the highest emissions is used to represent the maximum hourly emissions. Emissions from Standing Idle are routed to the vapor combustion unit (EPN VCU-TKS). The VCU will have a destruction efficiency of 99% for VOC, Benzene, and H_2S.

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[6] TCEQ, MSS Guidance, Background Document. Source: https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/mss/mss-guidance.pdf

[7] API, Technical Report 2567, Evaporative Loss from Storage Tank Floating Roof Landings, April 2005.

[8] API, Technical Report 2568, Evaporative Loss from the Cleaning of Storage Tanks, November 2007.

[9] AP-42 Chapter 7.1, Organic Liquid Storage Tanks, November 2006.

3.4.1.2. Tank Degassing

Tank degassing (initial vapor purge) emissions for all tanks are calculated using TCEQ's MSS Guidance. Emissions from tank degassing are routed to the vapor combustion unit (EPN VCU-TKS). The VCU will have a destruction efficiency of 99% for VOC, Benzene, and H_2S. The VOC saturation factor of 60% is obtained from TCEQ's MSS Guidance (API 2568).

3.4.1.3. Tank Forced Ventilation

After initial degassing, the emissions associated with the additional purging are covered under the forced ventilation emission calculations. All tanks will be operated in the same manner. Tank forced ventilation with diluted sludge emissions for all tanks are calculated using TCEQ's MSS Guidance.

3.4.1.4. Tank Refilling/Roof Refloating

Tank refilling/roof refloating emissions for all tanks are calculated using TCEQ's MSS Guidance (API 2568). During planned MSS events, refilling of tanks will occur after tank cleaning has been performed with forced degassing. A saturation factor of 0.15 is used for drain dry tanks.

Additional situations at the site can lead to tank landings and subsequent tank refilling/roof refloating; however, these activities are defined as emergency events or scheduled MSS and do not require authorization. Examples of these activities include emergency mixer or valve repairs. During these situations, TGTI will comply with 30 TAC Chapter 101 requirements and will utilize the vapor destruction unit for additional control.

3.4.1.5. Tank Sludge Removal/Vacuum Truck Venting

Additional MSS activities include emissions from the sludge removal and the vacuum truck venting. It is assumed that 90% of the emissions from sludge will be captured in the vacuum truck.

Vacuum trucks are placed at the site during MSS activities in order to remove the sludge from the bottom of the tanks, which are then shipped offsite. The number of vacuum trucks required will be based on the amount of volume needed to be removed. It is assumed that a total of twenty (20) trucks each with a 100 barrel capacity will be required to adequately cover the sludge from the tanks in a given year. Emissions from these tanks are calculated using saturation factor of 0.6 based on AP-42 Table 5.2-1, Chapter 5.2, Transportation and Marketing of Petroleum Liquids for submerged loading using dedicated normal service.

3.4.2. Pipeline Cleaning Activities

The planned and predictable maintenance activities include pipeline pigging. Equipment draining emissions are calculated using the loading loss emission factor obtained from AP-42 Chapter 5.2, Transportation and Marketing of Petroleum Liquids and taking the maximum volume of the equipment to be drained (i.e., line clearing, pig receivers).[10] When lines are opened for repairs, the VOC emissions result from clingage in the line (i.e., line breaks). VOC clingage emissions are calculated using TCEQ's MSS Guidance.

A statement of basis is included at the top of the pigging MSS emission source calculation, which provides the equations used and an explanation of the calculation performed. These calculations are based on the use of the ideal gas law. Additionally, pipeline pigging clingage emissions are based on the liquid density of the product. Emissions from the MSS operations on site are summarized in the following table.

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[10] AP-42 Chapter 5.2, Transportation and Marketing of Petroleum Liquids, June 2008.

3.4.3. Oil-water Separator

The TGTI Onshore Terminal will have one oil-water separator (EPN OWS) to separate water draws from storage tanks. The oil-water separator will receive a mixture of crude oil, sludge, distillate material, and water. The worst-case crude properties that could generate the highest emission rates are conservatively used in the calculations.

Emissions are calculated based on VOC concentration of 100 ppmv at breakthrough, the volume of loading, and the ideal gas law equation. The volume includes the vapor displaced due to loading the separator, as well as the standing losses of the separator. The annual uncontrolled standing losses of the separator are calculated in accordance with U.S. EPA AP-42 Section 7.1.3.1 (November 2006), conservatively assuming the average liquid level is zero.

Table 3-5. Summary of MSS Emissions at the TGTI Onshore Terminal

EPN	Description	Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
VCU-TKS	Vapor Combustion Unit for Controlled Standing Idle, Degassing, and Refilling Activities	VOC	11.23	0.68
		NO_X	2.10	0.13
		CO	4.19	0.25
		$PM/PM_{10}/PM_{2.5}$	0.16	<0.01
		SO_2	0.04	<0.01
		H_2S	<0.01	<0.01
		Benzene	0.08	<0.01
TKS-MSS	Sludge removal and Vacuum Truck Venting Activities	VOC	4.05	0.17
		H_2S	<0.01	<0.01
		Benzene	0.03	<0.01
P-MSS	Pipeline MSS Emissions	VOC	2.22	<0.01
		H_2S	<0.01	<0.01
		Benzene	0.02	<0.01
OWS	Oil-water Separator	VOC	0.67	0.28
		H_2S	<0.01	<0.01
		Benzene	<0.01	<0.01

4. IMPACTS EVALUATION

The NRSP requires an impacts evaluation for National Ambient Air Quality Standards [NAAQS; nitrogen dioxide (NO_2) and SO_2], State Property Line Standards (SO_2 and H_2S), and State Health Effects Review (benzene).

Per the NRSP, if an off-site receptor is greater than one (1) mile from the site, no further analysis is required for a State Health Effects Evaluation. If the property line is greater than one (1) mile from the emission sources, then no further analysis is required for NAAQS or State Property Line Standards. Since the closest off-site receptor is greater than 1 mile from the site, a State Health Effects Evaluation is not required.

Since the nearest off-site receptor is greater than 1 mile from the site, analysis for benzene is not required under State Health Effects Evaluation. The de minimis thresholds for impacts evaluation, as specified in the NRSP Section (k)(3)(C), are shown in Table 4-1 below. Based on the emissions calculations shown in Appendix B of this application and shown in Table 4-1 below, the emissions of NO_X are above the specified de minimis limit; therefore, further impacts evaluation is required. For the NO_2 emissions, if the corresponding SIL is exceeded, the screening background concentration is added to the modeled impacts for comparison to the NAAQS in accordance with TCEQ oil and gas modeling guidance. Since the TGTI Onshore Terminal will be located in TCEQ Region 14, NO_2 1-hour screening background concentration of 70 μg/m^3 was used per TCEQ guidance.

Per the TCEQ's Oil and Gas Standard Permit by Rule Refined- Screening Modeling Guidelines, "short-term standards are usually the controlling concentrations; that is, if the standard is met for the shortest time period, standards for longer averaging periods will also be met." Therefore, if the predicted concentrations from the maximum 1-hour emissions for a NAAQS or applicable state standard are at or are lower than the concentrations from a longer averaging period, the demonstration is complete. An impacts evaluation demonstrating compliance with the hourly and annual NO_2 NAAQS is, therefore, included in this section. Generic screening modeling tables specified in NRSP Section (m) are used to demonstrate compliance with the required standards. Since the firewater pump and emergency generator[11] engines operate for less than 100 hours per year each, emissions from the engines were annualized. As shown in Table 4-2, the sum of screening impacts from the engine and the vapor combustion unit were above the SIL. When the background concentration of 90 μg/m^3, as mentioned above, was added, the overall concentration was less than the NAAQS value of 188 μg/m^3. Similarly, for the annual averaging period, the screening impacts of the engine and the fire water pump were added to the screening impacts of the vapor combustion unit. The sum of the impacts for the annual averaging period of NO_2 was less than the NO_2 SIL of 1 μg/m^3 for the annual averaging period. Therefore no further impacts analysis is required.

Table 4-1. Impacts Evaluation Required?

	Hourly NO_2	Hourly SO_2	Hourly H_2S	Hourly Benzene
	E (lb/hr)	E (lb/hr)	E (lb/hr)	E (lb/hr)
Current Site-wide Total	22.34	0.07	3.16E-03	2.13
De minimis Limits[1]	4	2	0.025	0.039
Impacts Review Required?	Yes	No	No	N/A[2]

[11] The emergency generator is authorized under PBR 106.511; therefore it is not included in this Non-rule Standard Permit.

[1]De minimis limits per the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, Effective November 8, 2012, (k)(3)(C)

[2] An impacts evaluation is not required for benzene as the Terminal meets the requirements under (k)(3)(A) per the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, Effective November 8, 2012 is defined in 101.1(115) and does not include methane and ethane.

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Table 4-2. NO_2 Impacts Evaluation

NO_2 Impacts Evaluation - Hourly

						Hourly Impact Analysis [1]								
EPN	Description	Which impacts table corresponds to this EPN?	Distance to Property Line (ft)	Height of Release Point (ft)	G_{EPNx} [2] ($\mu g/m^3$)/(lb/hr)	Proposed NO_2 Hourly Emissions [3] (lb/hr)	$E_{EPNx, hourly}$ [4] ($\mu g/m^3$)	$E_{total, hourly}$ ($\mu g/m^3$)	$SIL_{NO2, hourly}$ ($\mu g/m^3$)	Is Modeled Concentration < SIL?	TCEQ Region 14 NO_2 1-hr Background Concentration ($\mu g/m^3$)	Background Concentration + Estimate Hourly Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Overall NO_2 1-hr Concentration < NAAQS ?
FWP-1	Firewater Pump	Engine	401	8	17	0.14	2.33	46.94	7.5	NO	70	116.94	188	YES
VCU-TKS	Vapor Combustion Unit	Thermal Destruction Device	250	60	23	1.89	43.40							
EGEN-01	Emergency Generator	Engine	299	8	17	0.07	1.20							

[1] Project emissions are representative of site-wide emissions since this is a new site under the Non-Rule Standard Permit.
[2] G_{EPNx} values obtained from Tables 3 and 5D of the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, Effective November 8, 2012.
[3] The NO_x-to-NO_2 ratio of 0.9 is applied for all sources.
[4] The Modeled Hourly Concentration for each EPN ($\mu g/m^3$) = Modeled Hourly Emission Increase (lb/hr) x Ground Level Concentration from the Table ($\mu g/m^3$)/(lb/hr)

NO_2 Impacts Evaluation - Annual

						Annual Impacts Analysis [1]						
EPN	Description	Which impacts table corresponds to this EPN?	Distance to Property Line (ft)	Height of Release Point (ft)	G_{EPNx} [2] ($\mu g/m^3$)/(lb/hr)	Proposed NO_2 Annual Emissions [3] (tpy)	NO_2 Hourly Emissions [4] (lb/hr)	$E_{EPNx, annual}$ [5] ($\mu g/m^3$)	$E_{total, annual}$ ($\mu g/m^3$)	$SIL_{NO2, annual}$ ($\mu g/m^3$)	Is Modeled Concentration < SIL?	NAAQS ($\mu g/m^3$)
FWP-1	Firewater Pump	Engine	50	8	17	0.60	0.14	0.19	0.33	1	YES	100
VCU-TKS	Vapor Combustion Unit	Thermal Destruction Device	175	60	23	0.11	0.03	0.05				
EGEN-01	Emergency Generator	Engine	299	8	17	0.31	0.07	0.10				

[1] Project emissions are representative of site-wide emissions since this is a new site under the Non-Rule Standard Permit.
[2] G_{EPNx} values obtained from Tables 3 and 5D of the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, Effective November 8, 2012.
[3] The NO_x-to-NO_2 ratio of 0.9 is applied for all sources.
[4] Modeled hourly emissions average the annual emissions over an entire year of operation. Modeled Hourly Emissions (lb/hr) = Annual Emissions Increase (tpy) / 8,760 (hrs/yr) x 2,000 (lb/ton)
[5] The Modeled Annual Concentration for each EPN ($\mu g/m^3$) = Modeled Hourly Emission Increase (lb/hr) x Ground Level Concentration from the Table ($\mu g/m^3$)/(lb/hr) x 0.08

5. GENERAL STANDARD PERMIT REQUIREMENTS

According to the NRSP, Section (g), the site must comply with all applicable requirements of 30 TAC §116.610; §116.611, Registration to Use a Standard Permit; §116.614, Standard Permit Fees; and §116.615, General Conditions. The NRSP supersedes the notification requirements of 30 TAC §116.615, General Conditions and the emission limitations of 30 TAC §116.610(a)(1), Applicability.

5.1. APPLICABILITY (30 TAC §116.610) EFFECTIVE FEBRUARY 1, 2006

(a) Under the Texas Clean Air Act, §382.051, a project that meets the requirements for a standard permit listed in this subchapter or issued by the commission is hereby entitled to the standard permit, provided the following conditions listed in this section are met. For the purposes of this subchapter, project means the construction or modification of a facility or a group of facilities submitted under the same registration.

(1) Any project that results in a net increase in emissions of air contaminants from the project other than carbon dioxide, water, nitrogen, methane, ethane, hydrogen, oxygen, or those for which a national ambient air quality standard has been established must meet the emission limitations of §106.261 of this title (relating to Facilities (Emission Limitations), unless otherwise specified by a particular standard permit.

The NRSP supersedes the emission limitations of this citation per Section (g). As such, this analysis is not required.

(2) Construction or operation of the project must be commenced prior to the effective date of a revision to this subchapter under which the project would no longer meet the requirements for a standard permit.

The project will meet the requirements of the current version of the NRSP at the time construction and operation commences.

(3) The proposed project must comply with the applicable provisions of the Federal Clean Air Act (FCAA), §111 (concerning New Source Performance Standards) as listed under 40 Code of Federal Regulations (CFR) Part 60, promulgated by the United States Environmental Protection Agency (EPA).

The TGTI Onshore Terminal will comply with all applicable New Source Performance Standards (NSPS), as discussed in Section 8 of this application.

(4) The proposed project must comply with the applicable provisions of FCAA, §112 (concerning Hazardous Air Pollutants) as listed under 40 CFR Part 61, promulgated by the EPA.

There are no National Emission Standards for Hazardous Air Pollutants (NESHAP) standards in 40 CFR Part 61 applicable to the sources included in this registration.

(5) The proposed project must comply with the applicable maximum achievable control technology standards as listed under 40 CFR Part 63, promulgated by the EPA under FCAA, §112 or as listed under Chapter 113, Subchapter C of this title (relating to National Emissions Standards for Hazardous Air Pollutants for Source Categories (FCAA, §112, 40 CFR Part 63)).

The TGTI Onshore Terminal will comply with all applicable NESHAP (40 CFR Part 63), as discussed in Section 8 of this application.

(6) If subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) the proposed facility, group of facilities, or account must obtain allocations to operate.

The TGTI Onshore Terminal will be located in Nueces County, which is not part of the Houston-Galveston-Brazoria ozone nonattainment area; therefore, the Mass Emissions Cap and Trade program requirements do not apply.

(b) Any project that constitutes a new major stationary source or major modification as defined in §116.12 of this title (relating to Nonattainment and Prevention of Significant Deterioration Review Definitions) is subject to the requirements of §116.110 of this title (relating to Applicability) rather than this subchapter.

The TGTI Onshore Terminal will be located in Nueces County, which is considered attainment or unclassified for all criteria pollutants; therefore, NNSR permitting requirements do not apply. The project does not constitute a new major stationary source under the PSD program, as shown in Section 3 of this registration; therefore, PSD permitting requirements do not apply and the NRSP can be claimed.

(c) Persons may not circumvent by artificial limitations the requirements of §116.110 of this title.

This registration is submitted to demonstrate compliance with the Standard Permit regulations. Texas Gulf Terminals is not circumventing the requirements of 116.110 through the use of artificial limitations.

(d) Any project involving a proposed affected source (as defined in §116.15(1) of this title (relating to Section 112(g) Definitions)) shall comply with all applicable requirements under Subchapter E of this chapter (relating to Hazardous Air Pollutants: Regulations Governing Constructed or Reconstructed Major Sources (FCAA, §112(g), 40 CFR Part 63)). Affected sources subject to Subchapter E of this chapter may use a standard permit under this subchapter only if the terms and conditions of the specific standard permit meet the requirements of Subchapter E of this chapter.

The project does not involve an affected source as defined in 30 TAC §116.15(1). Therefore, this paragraph does not apply.

5.2. REGISTRATION TO USE A STANDARD PERMIT (30 TAC §116.611) EFFECTIVE DECEMBER 11, 2002

(a) If required, registration to use a standard permit shall be sent by certified mail, return receipt requested, or hand delivered to the executive director, the appropriate commission regional office, and any local air pollution program with jurisdiction, before a standard permit can be used. The registration must be submitted on the required form and must document compliance with the requirements of this section, including, but not limited to:

(1) the basis of emission estimates;

(2) quantification of all emission increases and decreases associated with the project being registered;
(3) sufficient information as may be necessary to demonstrate that the project will comply with §116.610(b) of this title (relating to Applicability);
(4) information that describes efforts to be taken to minimize any collateral emissions increases that will result from the project;
(5) a description of the project and related process; and
(6) a description of any equipment being installed.

This registration for the TGTI Onshore Terminal includes all required items and are being submitted to TCEQ.

(b) Construction may begin any time after receipt of written notification from the executive director that there are no objections or 45 days after receipt by the executive director of the registration, whichever occurs first, except where a different time period is specified for a particular standard permit.

The NRSP specifies that construction may begin any time after receipt of a pre-construction notification. Texas Gulf Terminals submitted a pre-construction notification to the TCEQ via STEERS. The notification was given a Registration Number 151335.

(c) In order to avoid applicability of Chapter 122 of this title (relating to Federal Operating Permits), a certified registration shall be submitted. The certified registration must state the maximum allowable emission rates and must include documentation of the basis of emission estimates and a written statement by the registrant certifying that the maximum emission rates listed on the registration reflect the reasonably anticipated maximums for operation of the facility. The certified registration shall be amended if the basis of the emission estimates changes or the maximum emission rates listed on the registration no longer reflect the reasonably anticipated maximums for operation of the facility. The certified registration shall be submitted to the executive director; to the appropriate commission regional office; and to all local air pollution control agencies having jurisdiction over the site. Certified registrations must also be maintained in accordance with the requirements of §116.115 of this title (relating to General and Special Conditions).

(1) Certified registrations established prior to the effective date of this rule shall be submitted on or before February 3, 2003.
(2) Certified registrations established on or after the effective date of this rule shall be submitted no later than the date of operation.

The TGTI Onshore Terminal will be a minor source under Chapter 122 requirements, relating to Title V permitting. The NRSP registration is inherently considered to be federally enforceable. As such, this registration serves as the certified registration demonstrating that emissions are below the Title V thresholds.

5.3. STANDARD PERMIT FEES (30 TAC §116.614) EFFECTIVE OCTOBER 20, 2002

Any person who registers to use a standard permit or an amended standard permit, or to renew a registration to use a standard permit shall remit, at the time of registration, a flat fee of $900 for each standard permit being registered, unless otherwise specified in a particular standard permit. No fee is required if a registration is automatically renewed by the commission. All standard permit fees will be remitted in the form of a check, certified

check, electronic funds transfer, or money order made payable to the Texas Commission on Environmental Quality (TCEQ) and delivered with the permit registration to the TCEQ, P.O. Box 13088, MC 214, Austin, Texas 78711-3087. No fees will be refunded.

Texas Gulf Terminals has paid the $50 pre-construction notification fee and $850 registration fee, as required in the NRSP through STEERS.[12]

5.4. GENERAL CONDITIONS (30 TAC §116.615) EFFECTIVE MARCH 15, 2007

The following general conditions are applicable to holders of standard permits, but will not necessarily be specifically stated within the standard permit document.

(1) Protection of public health and welfare. The emissions from the facility, including dockside vessel emissions, must comply with all applicable rules and regulations of the commission adopted under Texas Health and Safety Code, Chapter 382, and with the intent of the Texas Clean Air Act (TCAA), including protection of health and property of the public.

This standard permit registration documents that the proposed project will comply with the rules and regulations of the TCEQ and the intent of the Texas Clean Air Act (TCAA), including protection of health and property of the public.

(2) Standard permit representations. All representations with regard to construction plans, operating procedures, and maximum emission rates in any registration for a standard permit become conditions upon which the facility or changes thereto, must be constructed and operated. It is unlawful for any person to vary from such representations if the change will affect that person's right to claim a standard permit under this section. Any change in condition such that a person is no longer eligible to claim a standard permit under this section requires proper authorization under §116.110 of this title (relating to Applicability). If the facility remains eligible for a standard permit, the owner or operator of the facility shall notify the executive director of any change in conditions which will result in a change in the method of control of emissions, a change in the character of the emissions, or an increase in the discharge of the various emissions as compared to the representations in the original registration or any previous notification of a change in representations. Notice of changes in representations must be received by the executive director no later than 30 days after the change.

Texas Gulf Terminals understands that standard permit representations become conditions upon which the facility must be operated. Any changes to the representations in this registration will be communicated to the TCEQ, as required in 30 TAC §116.615(2).

(3) Standard permit in lieu of permit amendment. All changes authorized by standard permit to a facility previously permitted under §116.110 of this title shall be administratively incorporated into that facility's permit at such time as the permit is amended or renewed.

TGTI Onshore Terminal will not operate under a TAC Chapter 116 case-by-case permit; therefore, this citation does not apply.

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[12] Per Non-Rule Standard Permit, Section 6002(f)(5)(C).

(4) Construction progress. Start of construction, construction interruptions exceeding 45 days, and completion of construction shall be reported to the appropriate regional office not later than 15 working days after occurrence of the event, except where a different time period is specified for a particular standard permit.

The requirements in the NRSP supersede these notification requirements per Section (g).

(5) Start-up notification.

(a) The appropriate air program regional office of the commission and any other air pollution control agency having jurisdiction shall be notified prior to the commencement of operations of the facilities authorized by a standard permit in such a manner that a representative of the executive director may be present.

(b) For phased construction, which may involve a series of units commencing operations at different times, the owner or operator of the facility shall provide separate notification for the commencement of operations for each unit.

(c) Prior to beginning operations of the facilities authorized by the permit, the permit holder shall identify to the Office of Permitting, Remediation, and Registration, the source or sources of allowances to be utilized for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program).

(d) A particular standard permit may modify start-up notification requirements.

The requirements in the NRSP supersede these notification requirements per Section (g).

(6) Sampling requirements. If sampling of stacks or process vents is required, the standard permit holder shall contact the commission's appropriate regional office and any other air pollution control agency having jurisdiction prior to sampling to obtain the proper data forms and procedures. All sampling and testing procedures must be approved by the executive director and coordinated with the regional representatives of the commission. The standard permit holder is also responsible for providing sampling facilities and conducting the sampling operations or contracting with an independent sampling consultant.

If stack sampling is required by the Executive Director, Texas Gulf Terminals will comply with these stack sampling requirements.

(7) Equivalency of methods. The standard permit holder shall demonstrate or otherwise justify the equivalency of emission control methods, sampling or other emission testing methods, and monitoring methods proposed as alternatives to methods indicated in the conditions of the standard permit. Alternative methods must be applied for in writing and must be reviewed and approved by the executive director prior to their use in fulfilling any requirements of the standard permit.

Texas Gulf Terminals is not requesting any alternatives to emissions control methods, sampling or other emission testing methods, or monitoring methods proposed as alternative methods in the conditions of the Standard Permit. Texas Gulf Terminals understands that if changes are proposed, a demonstration of equivalency of methods will be required.

(8) Recordkeeping. A copy of the standard permit along with information and data sufficient to demonstrate applicability of and compliance with the standard permit shall be maintained in a file at the plant site and made available at the request of representatives of the executive director, the United States Environmental Protection Agency, or any air pollution control agency having jurisdiction. For facilities that normally operate unattended, this information shall be maintained at the nearest staffed location within Texas specified by the standard permit holder in the standard permit registration. This information must include, but is not limited to, production records and operating hours. Additional recordkeeping requirements may be specified in the conditions of the standard permit. Information and data sufficient to demonstrate applicability of and compliance with the standard permit must be retained for at least two years following the date that the information or data is obtained. The copy of the standard permit must be maintained as a permanent record.

Texas Gulf Terminals will maintain records, as required by the Standard Permit, and make them available to regulatory personnel upon request.

(9) Maintenance of emission control. The facilities covered by the standard permit may not be operated unless all air pollution emission capture and abatement equipment is maintained in good working order and operating properly during normal facility operations. Notification for emissions events and scheduled maintenance shall be made in accordance with §101.201 and §101.211 of this title (relating to Emissions Event Reporting and Recordkeeping Requirements; and Scheduled Maintenance, Startup, and Shutdown Reporting and Recordkeeping Requirements).

Texas Gulf Terminals will maintain the air pollution capture and abatement equipment for the facilities covered by this Standard Permit in good working order and will operate the air pollution capture and abatement equipment properly during normal facility operations. Notifications under 30 TAC §101.201 and §101.211 will be made, as necessary.

(10) Compliance with rules. Registration of a standard permit by a standard permit applicant constitutes an acknowledgment and agreement that the holder will comply with all rules, regulations, and orders of the commission issued in conformity with the TCAA and the conditions precedent to the claiming of the standard permit. If more than one state or federal rule or regulation or permit condition are applicable, the most stringent limit or condition shall govern. Acceptance includes consent to the entrance of commission employees and designated representatives of any air pollution control agency having jurisdiction into the permitted premises at reasonable times to investigate conditions relating to the emission or concentration of air contaminants, including compliance with the standard permit.

Texas Gulf Terminals will comply with all applicable rules, regulations, and orders of the TCEQ and U.S. EPA, as appropriate. Regulatory personnel will be allowed to enter the site at reasonable times, as necessary.

(11) Distance limitations, setbacks, and buffer zones. Notwithstanding any requirement in any standard permit, if a standard permit for a facility requires a distance, setback, or buffer from other property or structures as a condition of the permit, the determination of whether the distance, setback, or buffer is satisfied shall be made on the basis of conditions existing at the earlier of:

(a) the date new construction, expansion, or modification of a facility begins; or

(b) the date any application or notice of intent is first filed with the commission to obtain approval for the construction or operation of the facility.

Any distance limitations, setbacks, and buffer zones will be determined as required by this section.

6. SPECIFIC STANDARD PERMIT REQUIREMENTS

According to the NRSP (6002-Non-Rule, effective November 8, 2012), the following specific requirements apply.

6.1. AIR QUALITY STANDARD PERMIT FOR OIL AND GAS HANDLING AND PRODUCTION FACILITIES EFFECTIVE NOVEMBER 8, 2012

(a) ***Applicability****. This standard permit applies to all stationary facilities, or groups of facilities, at a site which handle gases and liquids associated with the production, conditioning, processing, and pipeline transfer of fluids or gases found in geologic formations on or beneath the earth's surface including, but not limited to, crude oil, natural gas, condensate, and produced water with the following conditions.*

(1) The requirements in paragraphs (a)-(k) of this standard permit are applicable in only for new projects and dependent facilities located in the Barnett Shale (Cooke, Dallas, Denton, Ellis, Erath, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Somervell, Tarrant, and Wise Counties) on or after April 1, 2011. For all other new projects and dependent facilities in all other counties of the state, paragraph (l) of this standard permit is applicable.

The TGTI Onshore Terminal will be located in Nueces County, which is not defined as a Barnett Shale County; therefore, Texas Gulf Terminals is voluntarily registering this facility under the NRSP.

(2) Only one Air Quality Standard Permit for Oil and Gas Handling and Production Facilities for an oil and gas site (OGS) may be registered for a combination of dependent facilities and authorizes all facilities in sweet or sour service. This standard permit may not be used if operationally dependent facilities are authorized by the permit by rule in Title 30, Texas Administrative Code (30 TAC) §106.352, Oil and Gas Handling and Production Facilities, or a permit under 30 TAC §116.111,General Application. Existing authorized facilities, or groups of facilities, at an OGS under this standard permit which are not changing certified character or quantity of emissions must only meet subsections (i) and (k) of this standard permit (protectiveness review and planned maintenance, startup, and shutdown (MSS) requirements) and otherwise retain their existing authorization. Other facilities which are not covered under this standard permit may be authorized by other authorizations at an OGS if (b)(6) and (k) of this standard permit are met.

The TGTI Onshore Terminal will be authorized under only one Standard Permit. There are no operationally dependent facilities authorized under a 116.111 case-by-case construction permit.

(3) This standard permit does not relieve the owner or operator from complying with any other applicable provision of the Texas Health and Safety Code, Texas Water Code, rules of the Texas Commission on Environmental Quality (TCEQ), or any additional local, state or federal regulations. Emissions that exceed the limits in this standard permit are not authorized and are violations.

Texas Gulf Terminals will comply with all other applicable provisions of the Texas Health and Safety Code, Texas Water Code, TCEQ rules, and any additional local, state, or federal regulations. Texas Gulf Terminals understands that emissions that exceed the limits set forth in the Standard Permit are not authorized and are considered violations.

(4) Emissions from upsets, emergencies, or malfunctions are not authorized by this standard permit. This standard permit does not regulate methane, ethane, or carbon dioxide.

No emissions from upsets, emergencies, or malfunctions are included in this authorization.

(b) ***Definitions and Scope.***

(1) Facility is a discrete or identifiable structure, device, item, equipment, or enclosure that constitutes or contains a stationary source. Stationary sources associated with a mine, quarry, or well test lasting less than 72 hours are not considered facilities.

(2) Receptor includes any building which is in use as a single or multi-family residence, school, day-care, hospital, business, or place of worship at the time this standard permit is registered. A residence is a structure primarily used as a permanent dwelling. A business is a structure that is occupied for at least 8 hours a day, 5 days a week, and does not include businesses who are handling or processing materials as described in subsection (a). This term does not include structures occupied or used solely by the owner or operator of the oil and gas facility, or the mineral rights owner of the property upon which the facility is located. All measurements of distance to receptors shall be taken from the emission release point at the oil and gas facility that is nearest to the point on the building that is nearest to the oil and gas facility.

(3) An OGS is defined as all facilities which meet the following:
(A) Located on contiguous or adjacent properties;
(B) Under common control of the same person (or persons under common control); and
(C) Designated under same 2-digit standard industrial classification (SIC) codes.

(4) For purposes of determining applicability of 30 TAC Chapter 122, Federal Operating Permits, the definitions of 30 TAC §122.10, General Definitions, apply.

(5) A project under this standard permit is defined as the following and must meet all requirements of this standard permit prior to construction or implementation of changes.
(A) Any new facility or new group of operationally dependent facilities at an OGS; or
(B) Physical changes to existing authorized facilities or group of facilities at an OGS which increase the potential to emit over previously registered emission limits; or
(C) Operational changes to existing authorized facilities or group of facilities at an OGS which increase the potential to emit over previously registered emission limits.

(6) For purposes of registration under this standard permit, the following facilities shall be included:
(A) All facilities or groups of facilities at an OGS which are operationally dependent on each other;
(B) Facilities must be located within a 1/4 mile of a project emission point, vent, or fugitive component, except for those components excluded in (b)(6)(C) of this standard permit;
(C) If piping or fugitive components are the only connection between facilities and the distance between facilities exceeds 1/4 mile, then the facilities are considered separate for purposes of this registration;
(D) The boundaries of the registration become fixed at the time this standard permit is registered. No individual facility may be authorized under more than one registration;
(E) Any facility or group of facilities authorized under an existing standard permit registration which is operationally dependent on a project must be revised to incorporate the project; and

(F) A registration may include facilities which are claiming 30 TAC §116.620, Installation and/or Modification of Oil and Gas Facilities as well as projects which are claiming this standard permit. Existing authorized facilities, or group of facilities, at an OGS under this standard permit which are not changing registered and certified character or quantity of emissions must only meet paragraphs (i) and (k) of this standard permit (the protectiveness review and planned maintenance, startup, and shutdown (MSS) requirements) until the registration is renewed after December 31, 2015, after which paragraphs (a) – (k) of this standard permit apply.

(7) For purposes of all previous claims of this standard permit (or any previous version of this standard permit) where no project is occurring:

(A) Existing authorized facilities, or group of facilities, which have not registered planned MSS activity emissions prior to the effective dates in (a)(1) of this standard permit must meet paragraph (i) of this standard permit (planned MSS) no later than January 5, 2012; or

(B) Existing authorized facilities, or group of facilities, which have registered planned MSS activity emissions and compliance with 30 TAC §116.620(a)(1) has been demonstrated prior to the effective dates in (a)(1) of this standard permit, must meet paragraph (i) of this standard permit (planned MSS) no later than the registration renewal submitted after December 31, 2015.

(8) For purposes of ensuring protection of public health and welfare and demonstrating compliance with applicable ambient air standards and effects screening levels, the impacts analysis as specified in paragraph (k) of this standard permit must be completed.

(A) All impacts analysis must be done on a contaminant-by- contaminant basis for any net project increases. If a claim under this standard permit is only for planned MSS under paragraph (i) of this standard permit, the analysis shall evaluate planned MSS scenarios only.

(B) Hourly and annual emissions shall be limited based on the most stringent of paragraphs (h) or (k) of this standard permit.

Texas Gulf Terminals will use outlined definitions, as applicable, for compliance determinations. This registration includes the facilities outlined in the scope of the NRSP. Texas Gulf Terminals has included the necessary representations within the registration to demonstrate compliance with the NRSP requirements.

(c) ***Authorized Facilities, Changes and Activities.***

(1) For existing OGS which are authorized by previous versions of this standard permit:

(A) A project requires registration unless otherwise specified.

(B) The following projects do not require registration, but must comply with best management practices in paragraph (e) of this standard permit, compliance demonstrations in paragraphs (i) and (j) of this standard permit and must be incorporated into the registration at the next revision or certification:

(i) Addition of any piping, fugitive components, any other new facilities that increase registered emissions less than or equal to 1.0 tpy volatile organic compounds (VOC), 5.0 tpy nitrogen oxides (NO_X), 0.01 tpy benzene, and 0.05 tpy hydrogen sulfide (H_2S) over a rolling 12-month period;

(ii) Changes to any existing facilities that increase registered emissions less than or equal to 1.0 tpy VOC, 5.0 tpy nitrogen oxides (NO_X), 0.01 tpy benzene, and 0.05 tpy H_2S over a rolling 12-month period; or

(iii) Total increases over a rolling 60-month period that are less than or equal to 5.0 tpy VOC or NO_X, 0.05 tpy benzene, or 0.1 tpy H_2S; or

(iv) Addition of any new engine rated less than 100 horsepower (hp); or

(v) Replacement of any facility if the new facility does not increase the previous registered emissions.

(C) In lieu of registering proposed changes under this standard permit, incremental emissions increases associated with construction of new facilities or changes to existing facilities may be authorized by 30 TAC §106.261, Facilities (Emission Limitations) or §106.262, Facilities (Emissions and Distance Limitations), if the maximum worst-case emissions also meet the limitations established by paragraphs (b)(8) and (k) of this standard permit for all air contaminants with proposed increases.

The entire TGTI Onshore Terminal is being authorized with this NRSP registration and is not authorized by previous versions of this Standard Permit; therefore, this section does not apply.

(2) All authorizations under this standard permit shall meet the following:

(A) New, changed, or replacement facilities shall not exceed the thresholds for major source or major modification as defined in 30 TAC §116.12, Nonattainment and Prevention of Significant Deterioration Review Definitions, and in Federal Clean Air Act §112(g) or §112(j);

(B) All facilities shall comply with all applicable 40 Code of Federal Regulations (CFR), Parts 60, 61, and 63 requirements for New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and Maximum Achievable Control Technology (MACT); and

(C) All facilities shall comply with all applicable requirements of 30 TAC Chapters 111, Control of Air Pollution from Visible Emissions and Particulate Matter, 112, Control of Air Pollution from Sulfur Compounds, 113, Standards of Performance for Hazardous Air Pollutants and for Designated Facilities and Pollutants, 115, Control of Air Pollution from Volatile Organic Compounds), and 117, Control of Air Pollution from Nitrogen Compounds.

The TGTI Onshore Terminal will not be subject to the Nonattainment New Source Review (NNSR) program since Nueces County is in attainment or unclassified county for all criteria pollutants. The TGTI Onshore Terminal project does not constitute a major source. The facility will comply with all applicable state and federal regulations, as outlined in Section 8 of this registration.

(3) To be eligible for this standard permit an applicant:

(A) shall meet all applicable requirements as set forth in this standard permit;

(B) shall not misrepresent or fail to fully disclose all relevant facts in obtaining the permit; and

(C) shall not be indebted to the state for failure to make payment of penalties or taxes imposed by the statutes or rules within the commission's jurisdiction.

The sources included in this Standard Permit registration meet the criteria set forth in this condition. Texas Gulf Terminals is not indebted to the state for failure to make payment of penalties or taxes imposed by the statutes or rules within the commission's jurisdiction.

(4) All facilities related to the operation of any OGS, under any version of this standard permit (or co-located at a site with an OGS standard permit), previously authorized by, and continuing to meet, the conditions of a permit by rule under 30 TAC Chapter 106, Permits by Rule (or any historical version) must:

(A) Be incorporated into this standard permit in any initial registration, revision, or renewal for this standard permit. These facilities will become authorized by this standard permit and previous authorizations will be voided.
(B) Meet all emission limits established by this standard permit and review in accordance with paragraph (b)(8) of this standard permit.
(C) Meet requirements of paragraphs (e), (i), and (j) of this standard permit for Best Management Practices and Minimum Requirements, Planned MSS, and associated Records, Sampling and Monitoring of this standard permit.
(D) Only if facilities or groups of facilities are changed in such a way as to increase the potential to emit, production processing capacity, or registered emission rate, the requirements in paragraph (e) (BACT) of this standard permit are required to be met. In all other cases, these facilities are not required to meet paragraph (e) of this standard permit.

The TGTI Onshore Terminal will comply with all applicable emission limits and BACT requirements established by this Standard Permit.

(d) ***Facilities and Exclusions***

(1) Only the following specific facilities and groups of facilities have been evaluated for this standard permit, along with supporting infrastructure equipment and facilities, and may be included in a registration:
(A) Fugitive components, including valves, pressure relief valves, pipe flanges and connectors, pumps, compressors, stuffing boxes, instrumentation and meters, natural gas driven pneumatic pumps, and other similar devices with seals that separate process and waste material from the atmosphere and the associated piping;
(B) Separators, including all gas, oil, and water physical separation units;
(C) Treatment and processing equipment, including heater-treaters, methanol injection, glycol dehydrators, molecular or mole sieves, amine sweeteners, H_2S scavenger chemical reaction vessels for sulfur removal, and iron sponge units;
(D) Cooling towers and associated heat exchangers;
(E) Gas recovery units, including cryogenic expansion, absorption, adsorption, heat exchangers, and refrigeration units;
(F) Combustion units, including engines, turbines, boilers, reboilers, and heaters;
(G) Storage tanks for crude oil, condensate, produced water fuels, treatment chemicals, slop and sump oils and pressure tanks with liquified petroleum gases;
(H) Surface facilities associated with underground storage of gas or liquids;
(I) Truck loading equipment;
(J) Control equipment, including vapor recovery systems, glycol and amine reboiler condensers, flares, vapor combustors, and thermal oxidizers; and
(K) Temporary facilities used for planned maintenance, and temporary control devices for planned start-ups and shutdowns.

(2) ***Exclusions****. The following are not authorized under this standard permit:*
(A) Sour water strippers or sulfur recovery units;
(B) Carbon dioxide hot carbonate processing units;
(C) Water injection facilities (these facilities may otherwise be authorized by 30 TAC §106.351, Salt Water Disposal);

(D) Liquefied petroleum gases, crude oil, or condensate transfer or loading into or from railcars, ships, or barges. These facilities may otherwise be authorized by 30 TAC §106.261, Facilities (Emission Limitations)) and §106.262, Facilities (Emissions and Distance Limitations);
(E) Incinerators for solid waste destruction;
(F) Remediation of petroleum contaminated water and soil. These facilities may otherwise be authorized by 30 TAC §106.533, Remediation; and
(G) Cooling Towers and heat exchangers with direct contact with gaseous or liquid process streams containing VOC, H_2S, halogens or halogen compounds, cyanide compounds, inorganic acids, or acid gases.

This registration includes only those sources specifically evaluated and allowed under this Standard Permit. The TGTI Onshore Terminal will not include any facilities not authorized by the Standard Permit.

(e) ***Best Management Practices (BMP) and Best Available Control Technology (BACT) Requirements.*** *For any project, and any associated emission control equipment registered under this standard permit this paragraph shall be met as applicable. These requirements are not applicable to existing, unchanging facilities until any renewal submitted after December 31, 2015.*

(1) All facilities which have the potential to emit air contaminants must be maintained in good working order and operated properly during facility operations. Each operator shall establish and maintain a program to replace, repair, and/or maintain facilities to keep them in good working order. The minimum requirements of this program shall include:
(A) Compliance with manufacturer's specifications and recommended programs applicable to equipment performance and effect on emissions, or alternatively, an owner or operator developed maintenance plan for such equipment that is consistent with good air pollution control practices.
(B) Cleaning and routine inspection of all equipment; and
(C) Replacement and repair of equipment on schedules which prevent equipment failures and maintain performance.

(2) Any OGS facility shall be operated at least 50 feet from any property line or receptor (whichever is closer to the facility). This distance limitation does not apply to the following:
(A) Any fugitive components that are used for isolation and or safety purposes may be located at one-half of the width of any applicable easement;
(B) Any facility at a location for which the distance requirements were satisfied at the time this standard permit is registered (provided that the authorization was maintained) regardless of whether a receptor is subsequently built or put to use less than 50 feet from any OGS facility; or
(C) Existing facilities which are located less than 50 feet from a property line or receptor when constructed and previously authorized. If modified or replaced, the operator shall consider, to the extent that good engineering practice will permit, moving these facilities to meet the 50 foot requirement. Replacement facilities must meet all other requirements of this standard permit.

(3) Engines and turbines shall meet the emission and performance standards listed in Table 6 in paragraph (m) and the following requirements:
(A) Liquid fueled engines used for back-up power generation and periodic power needs at the OGS are authorized if the fuel has no more than 0.05% sulfur and the engine is operated less than 876 hours per rolling 12-month period.

(B) Engines and turbines used for electric generation more than 876 hours per rolling 12-month period are authorized if no reliable electric service is readily available. In all other circumstances, electric generators must meet the technical requirements of the Air Quality Standard Permit for Electric Generating Unit (EGU) (not including the EGU standard permit registration requirements) and the emissions shall be included in the registration under this standard permit;

(C) All applicable requirements of 30 TAC Chapter 117; and

(D) All applicable requirements of 40 CFR Part 60 and 40 CFR Part 63.

(E) Compression ignition engines that are rated less than 225 kW (300 hp) and emit less than or equal to the emission tier for an equivalent sized model year 2008 non-road compression ignition engine located at 40 CFR § 89.112, Table 1 are authorized.

(4) Open-topped tanks or ponds containing VOCs or H_2S are allowed up to a PTE equal to 1 tpy of VOC and 0.1 tpy of H_2S.

(5) All process equipment and storage facilities individually must meet the requirements of BACT listed in Table 10 in paragraph (m). Any combination of process equipment and storage facilities with an uncontrolled PTE of equal to or greater than 25 tpy of VOC must also meet the requirements of Table 10, row titled "Combined Control Requirements." All of the following streams and facilities must be included for this site-wide assessment:

(A) For any gaseous vent stream with a concentration of 1% VOC must be considered for capture and control requirements;

(B) For any liquid stream with a potential to emit of equal to or greater than 1 tpy VOC for each vessel or storage facility.

(6) The following shall apply to all fugitive components associated with the project:

(A) All seals and gaskets in VOC or H_2S service shall be installed, checked, and properly maintained to prevent leaking. All components shall be physically inspected quarterly for leaks.

(B) New and replaced fugitive components and instrumentation in gas or liquid service with the uncontrolled potential to emit equal to or greater than 10 tpy VOC or 1 tpy H_2S are subject to a leak detection and repair (LDAR) program as specified in Table 9 in paragraph (m). Additional requirements are applicable where uncontrolled potential to emit equal to or greater than 25 tpy VOC or 5 tpy H_2S as specified in Table 9. Planned MSS from fugitive components must also meet the requirements of Table 9.

(C) All components found to be leaking shall be repaired. Every reasonable effort shall be made to repair a leaking component. All leaks not repaired immediately shall be tagged or noted in a log. At manned sites, leaks shall be repaired no later than 30 days after the leak is found. At unmanned sites, leaks shall be repaired no later than 60 days after the leak is found. If the repair of a component would require a unit shutdown, which would create more emissions than the repair would eliminate, the repair may be delayed until the next shutdown.

(D) Tank hatches, not designed to be completely sealed, shall remain closed (but not completely sealed in order to maintain safe design functionality) except for sampling, gauging, loading, unloading, or planned maintenance activities.

(E) To the extent that good engineering practices will permit, new and reworked valves and piping connections shall be located in a place that is reasonably accessible for leak checking during plant operation and underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

(7) Tanks and vessels must utilize a paint color that minimizes the effects of solar heating (including, but not limited to, white or aluminum). To meet this requirement the solar absorptance should be 0.43 or less, as referenced in Table 7.1-6 in Compilation of Air Pollutant Emission Factors (AP-42). Paint shall be applied according to paint producers recommended application requirements if provided and in sufficient quantity as to be considered solar resistant. Paint shall be maintained in good condition and will not compromise tank integrity. Minimal amounts of rust may be present not to exceed 10% of the external surface area of the roof or walls of the tank and in no way may compromise tank integrity. Additionally, up to 10% of the external surface area of the roof or walls of the tank or vessel may be painted with other colors to allow for identification and/or aesthetics. For tanks and vessels purposefully darkened to create the process reaction and help condense liquids from being entrained in the vapor or are in an area whereby a local, state, federal law, ordinance, or private contract predating this standard permit's effective date establishes in writing tank and vessel colors other than white, these requirements do not apply.

(8) All emission estimation methods including but not limited to computer programs such as GRI-GLYCalc, AmineCalc, E&P Tanks, and Tanks 4.0, must be used with monitoring data generated in accordance with Table 8 in subsection (m) of this section where monitoring is required. All emission estimation methods must also be used in a way that is consistent with protocols established by the commission or promulgated in federal regulations (NSPS, NESHAPS). Where control of emissions is relied upon to meet subsection (k) of this section, control monitoring is required.

(9) Process reboilers, heaters, and furnaces that are also used for control of waste gas streams may claim 50 to 99% destruction efficiency for VOCs and H_2S depending on the design and level of monitoring applied. The 90% destruction may be claimed where the waste gas is delivered to the flame zone or combustion fire box with basic monitoring as specified in paragraph (j). Any value greater than 90% and up to 99% destruction efficiency may be claimed where enhanced monitoring and/or testing are applied as specified in paragraph (j). If the waste gas is premixed with the primary fuel gas and used as the primary fuel in the device through the primary fuel burners, 99% destruction may be claimed with basic monitoring as specified in paragraph (j). In systems where the combustion device is designed to cycle on and off to maintain the designed heating parameters, and may not fully utilize the waste gas stream, records of run time and enhanced monitoring is required to claim any run time beyond 50%.

(10) Vapor recovery Systems (VRSs) may claim up to 100% control. The control efficiency is based on whether it is a mechanical VRU (mVRU) or a liquid VRU (lVRU). The VRUs must meet the appropriate design, monitoring and record-keeping in Table 7 and Table 8 in paragraph (m).

(11) Flares used for control of emissions from production, planned MSS, emergency, or upset events may claim design destruction efficiency of 98% for VOCs and H_2S and 99% for VOCs containing no more than three carbon atoms that contain no elements other than carbon and hydrogen. All flares must be designed and operated in accordance with the following:

(A) Meet specifications for minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring found in 40 CFR §60.18;

(B) If necessary to ensure adequate combustion, sufficient gas shall be added to make the gases combustible;

(C) An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes;

(D) An automatic ignition system may be used in lieu of a continuous pilot;

(E) Flares must be lit at all times when gas streams are present;
(F) Fuel for all flares shall be sweet gas or liquid petroleum gas except where only field gas is available and it is not sweetened at the site; and
(G) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed at total of 5 minutes during any two consecutive hours. Acid gas flares which must comply with opacity limits and records in accordance with 30 TAC §111.111(a)(4), Requirements for Specified Sources, regarding gas flares, are exempt from this visible emission limitation.
(H) Flares may be designed with steam or air assist to help reduce visible emissions from the flare but must meet the appropriate requirements in 40 CFR 60.18.
(I) At no time shall minimum heating values fall below the associated minimum heating value in 60.18

(12) Thermal oxidation and vapor combustion control devices may claim design destruction efficiency from 90 to 99.9% for VOCs and H_2S depending on the design and the level of monitoring and testing applied. A device designed for the variability of the waste gas streams it controls with basic monitoring to indicate oxidation or combustion is occurring when waste gas is directed to the device may claim 90% destruction efficiency. Devices with intermediate monitoring, designed for the variability of the waste gas streams they control, with a fire box or fire tube designed to maintain a temperature above 1,400 degrees Fahrenheit (F) for 0.5 seconds, residence time; or designed to meet the parameters of a flare with minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring as found in 40 CFR §60.18, but within a full or partial enclosure may claim a design destruction efficiency of 90 to 98%. Devices with enhanced monitoring and ports and platforms to allow stack testing may claim a 99% efficiency where the devices are designed for the variability of the waste gas streams they control, with a fire box or fire tube designed to maintain a temperature above 1,400 degrees F for 0.5 seconds, residence time. The devices that can claim 99% destruction efficiency may claim 99.9% destruction efficiency if stack testing is conducted and confirms the efficiency and the enhanced monitoring is adjusted to ensure the continued efficiency. Temperature and residence time requirements may be modified if stack testing is conducted to confirm efficiencies.

BMP and BACT requirements are addressed for the TGTI Onshore Terminal in Section 7 of this registration.

(f) ***Registration, Revision, and Renewal Requirements***

(1) For all previous claims of this standard permit (or any previous version of this standard permit) existing authorized facilities, or group of facilities, are not required to meet the requirements of this standard permit, with the exception of planned MSS, until a renewal under the standard permit is submitted after December 31, 2015.

(2) If no other changes except for authorizing planned MSS occurs at an existing OGS under this standard permit, or any previous version of this standard permit, (b)(7) applies.
(A) Records demonstrating compliance with paragraph (i) must be kept;
(B) If the OGS must certify emissions to establish nonapplicability of prevention of significant deterioration (PSD), nonattainment new source review (NNSR), or the federal operating permit programs, this certification may be filed using Form APD-CERT. No fee is required for this certification.

(C) Planned MSS shall be incorporated at the next revision or update to a registration under this standard permit after January 5, 2012, and no later than any renewal submitted after December 31, 2015.

(3) Facilities, groups of facilities or planned MSS from facilities registered under this standard permit cannot also be authorized by a permit under 30 TAC §116.111, General Application.

(4) Prior to construction or implementation of changes for any project which meets this standard permit a notification shall be submitted through the e-Permits system. This notification shall include the following:

(A) Identifying information (Core Data) and a general description of the project must be submitted through e-Permits (or if not available, hard-copy) using the "APD OGS New Project Notification."

(B) A fee of $25 for small businesses as defined in 30 TAC §106.50, or $50 for all others must be submitted through the commission's e-Pay system.

(5) For any registration which meets the emission limitations of this standard permit must meet the following:

(A) Within 90 days after start of operation or implemented changes (whichever occurs first), the facilities must be registered with a PI-1S Standard Permit Application.

(B) This registration shall include a detailed summary of maximum emissions estimates based on: site-specific or defined representative gas and liquid analysis; equipment design specifications and operations; material type and throughput; and other actual parameters essential for accuracy for determining emissions and compliance with all applicable requirements of this standard permit.

(C) The fee for this registration shall be $475 for small businesses, or $850 for all others.

(D) Construction may begin any time after receipt of written notification to the executive director. Operations may continue after receipt of registration if there are no objections or 45 days after receipt by the executive director of the registration, whichever occurs first.

(6) If an OGS emissions increase, either through a change in production or addition of facilities, the site may change authorization (Level 1 or Level 2 PBR in 30 TAC §106.352 or Standard Permit) in the following circumstances:

(A) Within 90 days from the initial notification of construction of an oil and gas facility, a registration can update the authorization mechanism by submitting an initial registration or revision to the PBR or Standard Permit.

(B) Within 90 days of the change of production or installation of additional equipment, by submitting an initial registration or revision to the PBR or Standard Permit.

(7) All registrations, registration revisions, and renewals shall be submitted to the commission through a PI-1S Standard Permit Registration Form. Fee requirements do not apply when there are changes in representations with no increase in emissions within 6-months after a standard permit registration has been issued.

TGTI submitted the preconstruction notification (STDPMT Notification 151335, Project No. 284021) for this project on April 09, 2018 via STEERS. TGTI is submitting this Standard Permit revision to authorize additional equipment and change in location of the TGTI Onshore Terminal. Although this submittal is within 6 months of the initial registration, there is an increase in

emissions; therefore, the fee requirements apply. Texas Gulf Terminals has submitted the pre-construction notification and $50 fee (Registration No. 151335) for this project via STEERS. A fee of $850 has also been submitted via STEERS.

(g) *Any claim under this standard permit must comply with all applicable requirements of 30 TAC §116.610; §116.611, Registration to Use a Standard Permit; §116.614, Standard Permit Fees; and §116.615, General Conditions. This standard permit supersedes: the notification requirements of 30 TAC §116.615, General Conditions; and the emission limitations of 30 TAC §116.610(a)(1), Applicability.*

The general Standard Permit requirements are addressed in Section 5 of this registration.

(h) ***Emission Limitations.*** *Total maximum estimated registered or certified emissions shall meet the most stringent of the following. All emissions estimates must be based on representative worst-case operations and planned MSS activities.*

(1) *Total maximum estimated annual emissions of any air contaminant shall not exceed the applicable limits for a major stationary source or major modification for PSD and NNSR as specified in 30 TAC §116.12.*

(2) *Emissions must meet the limitations established in paragraph (k) of this standard permit.*

(3) *Maximum emissions are limited to less than the following after any operator limitations or controls:*

Air contaminant	*steady-state or < 30 psig periodic releases lb/hr*	*≥ 30 psig periodic lb/hr up to 600 hr/yr*	*Total tpy*
*Total VOC**			*250*
*Total crude oil or condensate VOC**	*145*	*318*	
*Total natural gas VOC**	*750*	*1635*	
Benzene	*7*	*15.4*	*10.2*
Hydrogen sulfide	*10.8*	*9.8*	*47*
Sulfur dioxide	*93.2*		*250*
Nitrogen oxides	*121*		*250*
Carbon monoxide	*104*		*250*
PM10 and PM2.5	*28*		*15*

* VOC is defined in 101.1(115) and does not include methane and ethane

The total maximum emissions will meet the requirements of the Standard Permit, as illustrated in Section 3 and Appendix B of this registration.

(i) ***Planned Maintenance, Start-ups and Shutdowns (MSS).*** *For any facility, group of facilities or site using this standard permit or previous versions of this standard permit, the following shall apply:*

(1) Prior to January 5, 2012, representations and registration of planned MSS is voluntary, but if represented must meet the applicable limits of this standard permit. After January 5, 2012, all emissions from planned MSS activities and facilities must be considered for compliance with applicable limits of this standard permit unless otherwise specified in (b)(7). This standard permit may not be used at a site or for facilities authorized under 30 TAC §116.111 if planned MSS has already been authorized under that permit.

(2) As specified, releases of air contaminants during, or as result of, planned MSS must be quantified and meet the emission limits in this standard permit, as applicable. This analysis must include:
(A) Alternate operational scenarios or redirection of vent streams;
(B) Pigging, purging, and blowdowns;
(C) Temporary facilities if used for degassing or purging of tanks, vessels, or other facilities;
(D) Degassing or purging of tanks, vessels, or other facilities; and
(E) Management of sludge from pits, ponds, sumps, and water conveyances.

(3) Other planned MSS activities authorized by this standard permit are limited to the following. These planned MSS activities require only recordkeeping of the activity.
(A) Routine engine component maintenance including filter changes, oxygen sensor replacements, compression checks, overhauls, lubricant changes, spark plug changes, and emission control system maintenance.
(B) Boiler refractory replacements and cleanings.
(C) Heater and heat exchanger cleanings.
(D) Turbine hot standard permit swaps.
(E) Pressure relief valve testing, calibration of analytical equipment; Instrumentation/analyzer maintenance; replacement of analyzer filters and screens.

(4) Engine/compressor start-ups associated with preventative system shutdown activities have the option to be authorized as part of typical operations if:
(A) Prior to operation, alternative operating scenarios to divert gas or liquid streams are registered and certified with all supporting documentation;
(B) Engine/compressor shutdowns shall result in no greater than 4 lbs/hr of natural gas emissions; and
(C) Emissions which result from subsequent compressor start-up activities are controlled to a minimum of 98% efficiency for VOC and H_2S.

MSS activities are included in this registration and Texas Gulf Terminals will comply with the associated recordkeeping and quantification requirements set forth within the NRSP.

(j) ***Records, Sampling and Monitoring.*** *The following records shall be maintained at a site in written or electronic form and be readily available to the agency or local air pollution control program with jurisdiction upon request. All required records must be kept at the facility site. If the facility normally operates unattended, records must be maintained at an office within Texas having day-to-day operational control of the plant site. Other requirements, including but not limited to, federal recordkeeping or testing requirements, can be used to demonstrate compliance if the other requirements are at least as stringent as the associated requirements in the table below. Any documentation that is already being kept for other purposes will suffice for demonstrating requirements. If a control or method is not relied upon to meet this standard permit, then the associated sampling, monitoring, and records are not applicable.*
(1) Sampling and demonstrations of compliance shall include the requirements listed in Table 7 in paragraph (m) of this standard permit.

(2) Monitoring and records for demonstrations of compliance shall include the requirements listed in Table 8 in paragraph (m) of this standard permit.

Texas Gulf Terminals will maintain all records as required by the Standard Permit, including records demonstrating compliance with the requirements in Table 7 and Table 8 of the NRSP.

(k) ***Emission Limits Based on Impacts Evaluation****.*

(1) All impacts evaluations must be completed on a contaminant-by- contaminant basis for only any net emissions increases resulting from a project and must meet the following as appropriate:

(A) Compliance with state or federal ambient air standards shall be demonstrated for NO_2, SO_2, and H_2S at any property-line within one mile of a project.

(B) Compliance with hourly effects screening levels (ESLs) for benzene and annual ESL for benzene, shall be demonstrated at the nearest receptor within 1 mile of a project.

(2) Distance measurements shall be determined using the following:

(A) For each facility or group of facilities, the shortest corresponding distance from any emission point, vent, or fugitive component to the nearest receptor must be used with the appropriate compliance determination method with the published ESLs as found through the TCEQ internet webpage.

(B) For each facility or group of facilities, the shortest corresponding distance from any emission point, vent, or fugitive component to the nearest property line must be used with the appropriate compliance determination method with any applicable state or federal ambient air quality standard.

(3) Impacts evaluations are not required under the following cases:

(A) If there is no receptor within 1 mile of a registration no further ESL review is required.

(B) If there is no property line within 1 mile of a registration no further ambient air quality review is required.

(C) If the project total emissions are less than any of the following rates, no additional analysis or demonstration of the specified air contaminant is required:

Air contaminant	***lb/hr***
Benzene	*0.039*
Hydrogen sulfide	*0.025*
Sulfur dioxide	*2*
Nitrogen oxides	*4*

(4) Evaluation of emissions shall meet the following.

(A) For all evaluations of NO_X to NO_2 a conversion factor of 0.20 for 4 stroke rich and lean burn engines and 0.50 for 2-stroke engines may be used.

(B) The maximum predicted concentration or rate at the property boundary or receptor, whichever is appropriate, must not exceed a state or federal ambient air standard or ESL.

(5) The impacts analysis shall be based on the following facility emissions:

(A) The following shall be met for ESL reviews:

(i) If a project's air contaminant maximum predicted concentrations are equal to or less than 10% of the appropriate ESL, no further review is required;

(ii) If a project's air contaminant maximum predicted concentrations combined with project increases for that contaminant over a rolling 60-month period after the effective date of this revised standard permit are equal to or less than 25% of the appropriate ESL, no further review is required.

(iii) In all other cases, all facility emissions at an OGS, regardless of authorization type, located within 1 mile of a project requiring registration under this standard permit shall be evaluated.

(B) The following shall be met for state and federal ambient air quality standard reviews:

(i) If a project's air contaminant maximum predicted concentrations are equal to or less than 10% the significant impact level (SIL) (also known as de minimis impact in

(ii) 30 TAC 101, General Rules), no further review is required; In all other cases, all facility emissions at an OGS, regardless of authorization type, located within 1 mile of a project requiring registration under this standard permit shall be evaluated.

(6) Evaluation must comply with one of the methods listed with no changes or exceptions:

(A) Tables.

(i) Emission impact Tables 2 – 5F in paragraph (m) of this standard permit may be used in accordance with the limits and descriptions in Table 1 in paragraph (m).

(ii) Values in Tables 2 - 5F in paragraph (m) of this standard permit may be used with linear interpolation between height and distance points. A distance of less than 50 feet or greater than 5,500 feet may not be used. Release heights may not be extrapolated beyond the limits of any table and instead the minimum or maximum height will be used. If distances and release heights are not interpolated, the next lowest height and lesser distances shall be used for determination of maximum acceptable emissions. All facilities exempted from the distance to the property line restriction in paragraph (e)(2) of this standard permit must use 50 feet as the distance to the property line for those ambient standards based on property line.

(B) Screening Modeling. A screening model may be used to demonstrate acceptable emissions from an OGS under this standard permit if all of the parameters in the screening modeling protocol provided by the commission are met.

(C) Dispersion Modeling. A refined dispersion model may be used to demonstrate acceptable emissions from an OGS under this standard permit if all of the parameters in the refined dispersion modeling protocol provided by the commission are met.

The Impacts Evaluation is discussed in detail in Section 4 of this registration.

(l) *Existing, Unchanged Facilities and Projects Before Effective Date. The requirements in 30 TAC §116.620 are applicable to existing unchanged facilities and new or changing facilities as specified in paragraph (a)(1) of this standard permit.*

The TGTI Onshore Terminal is proposed and is not existing; therefore, this section does not apply.

(m) The following Tables shall be used as required by this standard permit.

Table 1 Emission Impact Tables Limits and Descriptions;
Table 2 Generic Modeling Results for Fugitives & Process Vents;

Table 3 Generic Modeling Results for Flares and Thermal Destruction Devices;
Table 4 Generic Modeling Results for Blowdowns, Purging, and Pigging;
Table 5A Generic Modeling Results for Engines Less Than or Equal to 250 hp;
Table 5B Generic Modeling Results for Engines Greater Than 250 hp to Less Than or Equal to 500 hp;
Table 5C Generic Modeling Results for Engines Greater Than 500 hp to Less Than or Equal to 1000 hp;
Table 5D Generic Modeling Results for Engines Greater Than 1000 hp to Less Than or Equal to 1500 hp;
Table 5E Generic Modeling Results for Engines Greater Than 1500 hp to Less Than or Equal to 2000 hp;
Table 5F Generic Modeling Results for Engines Greater Than 2000 hp Table 6 Engine and Turbine Emission and Operational Standards Table 7 Sampling and Demonstrations of Compliance;
Table 8 Monitoring and Records Demonstrations;
Table 9 Fugitive Component Leak Detection and Repair (LDAR) Control Program; and
Table 10 Best Available Control Technology (BACT) Requirements.

The aforementioned tables are used in the assessment of the applicable requirements for the NRSP. Texas Gulf Terminals will comply with the requirements set forth in the tables, as applicable.

7. BEST MANAGEMENT PRACTICES (BMP) AND BEST AVAILABLE CONTROL TECHNOLOGY (BACT) REQUIREMENTS

For any project and any associated emission control equipment registered under the NRSP, the following requirements shall be met, as applicable.

7.1. PROGRAM TO REPLACE, REPAIR, AND/OR MAINTAIN FACILITIES

(1) All facilities which have the potential to emit air contaminants must be maintained in good working order and operated properly during facility operations. Each operator shall establish and maintain a program to replace, repair, and/or maintain facilities to keep them in good working order. The minimum requirements of this program shall include:

(A) Compliance with manufacturer's specifications and recommended programs applicable to equipment performance and effect on emissions, or alternatively, an owner or operator developed maintenance plan for such equipment that is consistent with good air pollution control practices.

(B) Cleaning and routine inspection of all equipment; and

(C) Replacement and repair of equipment on schedules which prevent equipment failures and maintain performance.

Texas Gulf Terminals will comply with all applicable rules to maintain equipment in good working order and ensure the equipment is operated properly. Texas Gulf Terminals will establish and maintain a program to replace, repair, and/or maintain facilities to keep them in good working order. The program will comply with the requirements outlined above.

7.2. DISTANCE LIMITATIONS

(2) Any OGS facility shall be operated at least 50 feet from any property line or receptor (whichever is closer to the facility). This distance limitation does not apply to the following:

(A) Any fugitive components that are used for isolation and or safety purposes may be located at one-half of the width of any applicable easement;

(B) Any facility at a location for which the distance requirements were satisfied at the time this standard permit is registered (provided that the authorization was maintained) regardless of whether a receptor is subsequently built or put to use 50 feet from any OGS facility; or

(C) Existing facilities which are located less than 50 feet from a property line or receptor when constructed and previously authorized. If modified or replaced, the operator shall consider, to the extent that good engineering practice will permit, moving these facilities to meet the 50 foot requirement. Replacement facilities must meet all other requirements of this standard permit.

All emission sources will be operated at least 50 feet from any property line or receptor (whichever is closer to the facility), except as allowed.

7.3. ENGINES AND TURBINES

(3) Engines and turbines shall meet the emission and performance standards listed in Table 6 in paragraph (m) and the following requirements:

The TGTI Onshore Terminal will operate one (1) emergency firewater diesel engine. Table 6 (emission limits) of the Non-Rule Standard Permit does not apply to emergency engines.

(A) *Liquid fueled engines used for back-up power generation and periodic power needs at the OGS are authorized if the fuel has no more than 0.05% sulfur and the engine is operated less than 876 hours per rolling 12-month period.*

The engine will not be used for power generation; therefore, the requirement does not apply.

(B) *Engines and turbines used for electric generation more than 876 hours per rolling 12-month period are authorized if no reliable electric service is readily available. In all other circumstances, electric generators must meet the technical requirements of the Air Quality Standard Permit for Electric Generating Unit (EGU) (not including the EGU standard permit registration requirements) and the emissions shall be included in the registration under this standard permit;*

The engine will not be used for power generation; therefore, the requirement does not apply.

(C) *All applicable requirements of 30 TAC Chapter 117; and*

The TGTI Onshore Terminal will be located in Nueces County, which is not an affected county under 30 TAC Chapter 117; therefore, these requirements do not apply.

(D) *All applicable requirements of 40 CFR Part 60 and 40 CFR Part 63.*

The TGTI Onshore Terminal will operate one (1) emergency firewater compression ignition diesel engine. The engine has applicable requirements contained in either 40 CFR Part 60 Subpart IIII or 40 CFR part 63 Subpart ZZZZ. The details of the applicability determination are in Section 8 of this registration. Texas Gulf Terminals will comply with all applicable requirements.

(E) *Compression ignition engines that are rated less than 225 kW (300 hp) and emit less than or equal to the emission tier for an equivalent sized model year 2008 non-road compression ignition engine located at 40 CFR § 89.112, Table 1 are authorized.*

The engine horsepower (hp) will be greater than 300 hp; therefore, the requirement does not apply.

7.4. OPEN-TOPPED TANKS OR PONDS

(4) *Open-topped tanks or ponds containing VOCs or H_2S are allowed up to a PTE equal to 1 tpy of VOC and 0.1 tpy of H_2S.*

Texas Gulf Terminals is not proposing to install or operate any open-topped tanks or pods; therefore, these requirements do not apply.

7.5. PROCESS EQUIPMENT AND STORAGE FACILITIES

(5) All process equipment and storage facilities individually must meet the requirements of BACT listed in Table 10 in paragraph (m). Any combination of process equipment and storage facilities with an uncontrolled PTE of equal to or greater than 25 tpy of VOC must also meet the requirements of Table 10, row titled "Combined Control Requirements". All of the following streams and facilities must be included for this site-wide assessment:

(A) For any gaseous vent stream with a concentration of 1% VOC must be considered for capture and control requirements;

(B) For any liquid stream with a potential to emit of equal to or greater than 1 tpy VOC for each vessel or storage facility.

Texas Gulf Terminals will comply with all applicable requirements in Table 10 for process equipment and storage facilities.

VOC emissions for the TGTI Onshore Terminal are above 25 tpy; therefore, Texas Gulf Terminals will comply with the BACT combined control requirements as outlined in Table 10.

The twelve (12) sweet crude oil/condensate storage tanks, and the slop oil tank at the TGTI Onshore Terminal are internal floating roof tanks. The TGTI Onshore Terminal also contains a horizontal diesel storage tank and an oil-water separator. Most tank cleaning and degassing activity emissions are controlled using a vapor combustion unit with 99% control efficiency. Tank MSS emissions (EPN TKS-FV) are less than 1 tpy; therefore, these activities do not require control. Sources that are emitted as fugitives (e.g., equipment leak fugitives, truck loading) are also excluded from this analysis.

Uncontrolled tank normal emissions are greater than 1 tpy for each of the crude/condensate tanks. TGTI will implement the following control measures to meet the BACT requirements outlined in Table 10:

- **Tanks will be painted a color to minimize the effect of solar heating; and**
- **Tank hatches shall remain closed except as allowed by Table 10.**

All tanks have uncontrolled emissions less than 5 tpy and a capacity of greater than 500 gallons; therefore, they will be filled using submerged fill to comply with Table 10.

7.6. FUGITIVES

(6) The following shall apply to all fugitive components associated with the project:

(a) All seals and gaskets in VOC or H_2S service shall be installed, checked, and properly maintained to prevent leaking. All components shall be physically inspected quarterly for leaks.

(b) New and replaced fugitive components and instrumentation in gas or liquid service with the uncontrolled potential to emit equal to or greater than 10 tpy VOC or 1 tpy H_2S are subject to a leak detection and repair (LDAR) program as specified in Table 9 in paragraph (m). Additional requirements are applicable where uncontrolled potential to emit equal to or greater than 25 tpy VOC or 5 tpy H_2S as specified in Table 9. Planned MSS from fugitive components must also meet the requirements of Table 9.

(c) All components found to be leaking shall be repaired. Every reasonable effort shall be made to repair a leaking component. All leaks not repaired immediately shall be tagged or noted in a log. At manned sites, leaks shall be repaired no later than 30 days after the leak is found. At unmanned sites, leaks shall be repaired no later than 60 days after the leak is found. If the repair of a component would require a unit shutdown, which would create more emissions than the repair would eliminate, the repair may be delayed until the next shutdown.

(d) Tank hatches, not designed to be completely sealed, shall remain closed (but not completely sealed in order to maintain safe design functionality) except for sampling, gauging, loading, unloading, or planned maintenance activities.

(e) To the extent that good engineering practices will permit, new and reworked valves and piping connections shall be located in a place that is reasonably accessible for leak checking during plant operation and underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

The uncontrolled VOC emissions from equipment leak fugitives are between 10 tpy and 25 tpy; therefore, Texas Gulf Terminals will implement the TCEQ 28M LDAR program that meets these requirements.

7.7. TANKS

(7) Tanks and vessels must utilize a paint color that minimizes the effects of solar heating (including, but not limited to, white or aluminum). To meet this requirement the solar absorptance should be 0.43 or less, as referenced in Table 7.1-6 in Compilation of Air Pollutant Emission Factors (AP-42). Paint shall be applied according to paint producers recommended application requirements if provided and in sufficient quantity as to be considered solar resistant. Paint shall be maintained in good condition and will not compromise tank integrity. Minimal amounts of rust may be present not to exceed 10% of the external surface area of the roof or walls of the tank and in no way may compromise tank integrity. Additionally, up to 10% of the external surface area of the roof or walls of the tank or vessel may be painted with other colors to allow for identification and/or aesthetics. For tanks and vessels purposefully darkened to create the process reaction and help condense liquids from being entrained in the vapor or are in an area whereby a local, state, federal law, ordinance, or private contract predating this standard permit's effective date establishes in writing tank and vessel colors other than white, these requirements do not apply.

Texas Gulf Terminals will comply with all applicable requirements for painting the storage tanks, except as allowed.

7.8. ESTIMATION METHODS

(8) All emission estimation methods including but not limited to computer programs such as GRI-GLYCalc, AmineCalc, E&P Tanks, and Tanks 4.0, must be used with monitoring data generated in accordance with Table 8 in subsection (m) of this section where monitoring is required. All emission estimation methods must also be used in a way that is consistent with protocols established by the commission or promulgated in federal regulations (NSPS, NESHAPS). Where control of emissions is relied upon to meet subsection (k) of this section, control monitoring is required.

Texas Gulf Terminals will comply will all applicable requirements for estimation methods and the associated monitoring and recordkeeping requirements in Table 8.

7.9. PROCESS REBOILERS, HEATERS, AND FURNACES AS CONTROL DEVICES

(9) Process reboilers, heaters, and furnaces that are also used for control of waste gas streams may claim 50 to 99% destruction efficiency for VOCs and H2S depending on the design and level of monitoring applied. The 90% destruction may be claimed where the waste gas is delivered to the flame zone or combustion fire box with basic monitoring as specified in paragraph (j). Any value greater than 90% and up to 99% destruction efficiency may be claimed where enhanced monitoring and/or testing are applied as specified in paragraph (j). If the waste gas is premixed with the primary fuel gas and used as the primary fuel in the device through the primary fuel burners, 99% destruction may be claimed with basic monitoring as specified in paragraph (j). In systems where the combustion device is designed to cycle on and off to maintain the designed heating parameters, and may not fully utilize the waste gas stream, records of run time and enhanced monitoring is required to claim any run time beyond 50%.

Texas Gulf Terminals is not using any of these devices as a control; therefore, this subsection does not apply.

7.10. VAPOR RECOVERY UNITS

(10) Vapor recovery Systems (VRSs) may claim up to 100% control. The control efficiency is based on whether it is a mechanical VRU (mVRU) or a liquid VRU (lVRU). The VRUs must meet the appropriate design, monitoring and record-keeping in Table 7 and Table 8 in paragraph (m).

The TGTI Onshore Terminal will not operate any of these sources; therefore, no BMP or BACT is required.

7.11. FLARES AS CONTROL DEVICES

(11) Flares used for control of emissions from production, planned MSS, emergency, or upset events may claim design destruction efficiency of 98% for VOCs and H2S and 99% for VOCs containing no more than three carbon atoms that contain no elements other than carbon and hydrogen. All flares must be designed and operated in accordance with the following:

- *(a) Meet specifications for minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring found in 40 CFR §60.18;*
- *(b) If necessary to ensure adequate combustion, sufficient gas shall be added to make the gases combustible;*
- *(c) An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes;*
- *(d) An automatic ignition system may be used in lieu of a continuous pilot;*
- *(e) Flares must be lit at all times when gas streams are present;*
- *(f) Fuel for all flares shall be sweet gas or liquid petroleum gas except where only field gas is available and it is not sweetened at the site; and*

(g) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed at total of 5 minutes during any 2 consecutive hours. Acid gas flares which must comply with opacity limits and records in accordance with 30 TAC §111.111(a)(4), Requirements for Specified Sources, regarding gas flares, are exempt from this visible emission limitation.

(h) Flares may be designed with steam or air assist to help reduce visible emissions from the flare but must meet the appropriate requirements in 40 CFR 60.18.

(i) At no time shall minimum heating values fall below the associated minimum heating value in 60.18

The TGTI Onshore Terminal will not operate any flares; therefore, this is not applicable.

7.12. THERMAL OXIDATION AND VAPOR COMBUSTION DEVICES

(12) Thermal oxidation and vapor combustion control devices may claim design destruction efficiency from 90 to 99.9% for VOCs and H2S depending on the design and the level of monitoring and testing applied. A device designed for the variability of the waste gas streams it controls with basic monitoring to indicate oxidation or combustion is occurring when waste gas is directed to the device may claim 90% destruction efficiency. Devices with intermediate monitoring, designed for the variability of the waste gas streams they control, with a fire box or fire tube designed to maintain a temperature above 1,400 degrees Fahrenheit (F) for 0.5 seconds, residence time; or designed to meet the parameters of a flare with minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring as found in 40 CFR § 60.18, but within a full or partial enclosure may claim a design destruction efficiency of 90 to 98%. Devices with enhanced monitoring and ports and platforms to allow stack testing may claim a 99% efficiency where the devices are designed for the variability of the waste gas streams they control, with a fire box or fire tube designed to maintain a temperature above 1,400 degrees F for 0.5 seconds, residence time. The devices that can claim 99% destruction efficiency may claim 99.9% destruction efficiency if stack testing is conducted and confirms the efficiency and the enhanced monitoring is adjusted to ensure the continued efficiency. Temperature and residence time requirements may be modified if stack testing is conducted to confirm efficiencies.

The TGTI Onshore Terminal will operate a Vapor Combustion Unit (VCU) to control emissions from some MSS activities at its storage tanks. In accordance with the requirements above, a 99% DRE is claimed. Texas Gulf Terminals will comply with the applicable monitoring and design requirements for the control device.

8.1. STATE REQUIREMENTS REVIEW

> **30 TAC Chapter 111:**
  - Emission sources at the TGTI Onshore Terminal are subject to the regulations listed in 30 TAC 111.111(a) and 111.151. Texas Gulf Terminals will operate and maintain emissions sources so as not to exceed the applicable visible and particulate matter emissions limits.

> **30 TAC Chapter 112:**
  - All emission sources will comply with the applicable requirements of Chapter 112, regarding the control of sulfur compounds. None of the emission sources at the TGTI Onshore Terminal are subject to the source-specific emission limits in Chapter 112. The emissions sources at the TGTI Onshore Terminal are expected to comply with the SO_2 and H_2S net ground level concentration limits.

> **30 TAC Chapter 115:**
  - The TGTI Onshore Terminal is located in Nueces County, which is currently an affected county under Chapter 115. Emission sources at the TGTI Onshore Terminal are subject to the regulations listed in 30 TAC 115.112 and 115.114. Texas Gulf Terminals will operate and maintain emissions sources so as not to exceed the applicable requirements.

> **30 TAC Chapter 117:**
  - The TGTI Onshore Terminal is located in Nueces County, which is currently not an affected county under Chapter 117; therefore, there are no applicable requirements under this Chapter.

8.2. FEDERAL REQUIREMENTS REVIEW

8.2.1. Part 60 – New Source Performance Standards (NSPS)

> **40 CFR Part 60 Subpart A: *General Provisions***
  - Any source subject to a source-specific NSPS is also subject to the general provisions of NSPS Subpart A. Unless specifically excluded by the source-specific NSPS, Subpart A generally requires initial construction notification, initial startup notification, performance tests, performance test date initial notification, general monitoring requirements, general recordkeeping requirements, and semiannual monitoring and/or excess emission reports. Since the TGTI Onshore Terminal is subject to a source-specific NSPS, the Terminal will also subject to NSPS Subpart A and will comply with the applicable regulations.

> **40 CFR Part 60 Subpart Kb: *Storage Vessels***
  - This subpart applies to tanks constructed, reconstructed, or modified after July 23, 1984 and with a storage capacity of greater than 39,900 gallons and vapor pressure between 0.75 psia (5.2 kPa) and 11.1. psia (76.6 kPa). All storage tanks at the proposed TGTI Onshore Terminal (EPNs TK-501, TK-502, TK-503, TK-504, TK-505, TK-506, TK-507, TK-508, TK-509, TK-510, TK-511, TK-512 and TK-SLOP) are greater than 39,900 gallons. Tank TK-FWP has a storage capacity less than 39,900 gallons; therefore, this subpart is not applicable to TK-FWP.

> **40 CFR Part 60 Subpart KKK: *Equipment Leaks of VOC from Onshore Natural Gas Processing Plants***
  - This subpart applies to natural gas processing plants. The TGTI Onshore Terminal is not a processing plant; therefore, this subpart does not apply.

- **40 CFR Part 60 Subpart LLL:** ***Onshore Natural Gas Processing: SO_2 Emissions***
  - This subpart applies to natural gas processing plants that use a sulfur recovery unit. The TGTI Onshore Terminal is not a processing plant and does not utilize any sulfur recovery units; therefore, this subpart does not apply.

- **40 CFR Part 60 Subpart IIII:** ***Stationary Compression Ignition Internal Combustion Engines***
  - This subpart applies to compression ignition engines. There will be one (1) emergency compression ignition engine at the proposed TGTI Onshore Terminal. The Firewater Pump, which is a 1,300 horsepower (hp) engine, was constructed after the applicable date of July 11, 2005 and was manufactured after April 2006. Therefore, this subpart applies to the Engine. Texas Gulf Terminals will comply with NSPS IIII requirements for emergency engine as applicable.

- **40 CFR Part 60 OOOO:** ***Crude Oil and Natural Gas Production, Transmission, and Distribution***
  - This subpart applies to Crude Oil and Natural Gas Production, Transmission, and Distribution Facilities for onshore natural gas processing plants. NSPS Subpart OOOO regulates emissions and work practice standards for compressors, condensate tanks and fugitive sources installed after August 23, 2011, and on or before September 18, 2015.
  - The proposed emissions sources at the TGTI Onshore Terminal will be constructed after September 18, 2015; therefore, the sources proposed or affected by this project are not regulated by NSPS OOOO.

- **40 CFR Part 60 OOOOa:** ***Crude Oil and Natural Gas Facilities***
  - This subpart applies to Crude Oil and Natural Gas Facilities for which construction, modification, or reconstruction commenced after September 18, 2015. NSPS Subpart OOOOa regulates emissions and work practice standards for onshore affected facilities, such as compressors, storage tanks, pneumatic devices and pumps, and fugitive sources at oil & gas drill sites up to the point of custody transfer to oil transmission pipelines.
  - The proposed terminal will receive sweet crude oil from transmissions pipelines which is after the point of custody transfer from oil & gas drill sites. As a result, NSPS OOOOa does not apply to the TGTI Onshore Terminal.

8.2.2. Part 61 – National Emission Standards for Hazardous Air Pollutants

- **40 CFR Part 61 Subpart V:**
  - This subpart applies to sources that are intended to operate in volatile hazardous air pollutant service. This registration does not contain any sources in this service; therefore, this subpart does not apply.

8.2.3. Part 63 – National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT)

- **40 CFR Part 63 Subpart A:** ***General Provisions***
  - This subpart applies to any site that is subject to an individual MACT Subpart. Since the sources at the TGTI Onshore Terminal are subject to at least one MACT Subpart, Texas Gulf Terminals will comply with the general requirements in Subpart A.

- **40 CFR Part 63 Subpart HH:** ***Oil and Natural Gas Production Facilities***
  - There are no dehydrators at the TGTI Onshore Terminal; therefore, this subpart does not apply.

- **40 CFR Part 63 Subpart ZZZZ: *Stationary Reciprocating Internal Combustion Engines (RICE*)**
  - There will be one (1) emergency firewater compression ignition engine located at the TGTI Onshore Terminal. The engine will be subject to MACT Subpart ZZZZ. Texas Gulf Terminals will meet the requirements of MACT ZZZZ for the engine.

9. NNSR & PSD APPLICABILITY REVIEW

Under U.S. EPA and TCEQ rules, sites located in areas that are designated in attainment of the NAAQS for a criteria pollutant are potentially regulated under the PSD program if they are considered *major sources*. Major source thresholds are defined in 40 CFR §52.21 (b)(1)(i). The proposed site-wide VOC emissions and all criteria pollutant emissions are below the major source thresholds under the PSD program; therefore, the TGTI Onshore Terminal is not subject to PSD permitting.

NNSR applies to facilities located in areas designated as nonattainment for one or more of the criteria pollutants. The TGTI Onshore Terminal is located in Nueces County, which has been designated as an attainment or unclassified area for all criteria air pollutants.[13] As a result, the NNSR program does not apply to the proposed project.

[13] The United States Environmental Protection Agency (U.S. EPA) Green Book. Source: https://www3.epa.gov/airquality/greenbook/hbcs.html#TX, accessed in November 2017.

10. PROFESSIONAL ENGINEER (P.E.) SEAL

The professional engineer (P.E.) seal is attached in this section for the proposed project.

FORM PI-1 SECTION X PROFESSIONAL ENGINEER (P.E.) SEAL

I, Neelesh V. Sule, have reviewed the following sections of the attached application for the Non-Rule Standard Permit Amendment submitted by Texas Gulf Terminals, Inc:

Emissions Data

Best Available Control Technology

The capital cost of the project is estimated to be greater than $2,000,000.

The application for Non-Rule Standard Permit, as referenced above, was reviewed on the 15th day of June 2018.

Signed: STATE OF TEXAS NEELESH V. SULE 113323 LICENSED PROFESSIONAL ENGINEER

Date: June 15, 2018

Professional Engineer Registration Number: 113323

APPENDIX A: TCEQ TABLE 1(A)

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	June 2018	Permit No.:	151335	Regulated Entity No.	RN110317666
Area Name:	TGTI Onshore Terminal			Customer Reference No.	CN605490085

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) Pounds per Hour [1]	(B) TPY [1]
TK-501	TK-501	IFR Tank 501	VOC	11.06	6.88
			H_2S	<0.01	<0.01
			Benzene	0.16	0.09
TK-502	TK-502	IFR Tank 502	VOC	11.06	6.88
			H_2S	<0.01	<0.01
			Benzene	0.16	0.09
TK-503	TK-503	IFR Tank 503	VOC	11.06	6.88
			H_2S	<0.01	<0.01
			Benzene	0.16	0.09
TK-504	TK-504	IFR Tank 504	VOC	11.06	6.88
			H_2S	<0.01	<0.01
			Benzene	0.16	0.09
TK-505	TK-505	IFR Tank 505	VOC	11.06	6.88
			H_2S	<0.01	<0.01
			Benzene	0.16	0.09
TK-506	TK-506	IFR Tank 506	VOC	11.06	6.88
			H_2S	<0.01	<0.01
			Benzene	0.16	0.09
TK-507	TK-507	IFR Tank 507	VOC	11.06	6.88
			H_2S	<0.01	<0.01
			Benzene	0.16	0.09

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	June 2018	Permit No.:	151335	Regulated Entity No.	RN110317666
Area Name:	TGTI Onshore Terminal			Customer Reference No.	CN605490085

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) Pounds per Hour [1]	(B) TPY [1]
TK-508	TK-508	IFR Tank 508	VOC	11.06	6.88
			H_2S	<0.01	<0.01
			Benzene	0.16	0.09
TK-509	TK-509	IFR Tank 509	VOC	11.06	6.88
			H_2S	<0.01	<0.01
			Benzene	0.16	0.09
TK-510	TK-510	IFR Tank 510	VOC	11.06	6.88
			H_2S	<0.01	<0.01
			Benzene	0.16	0.09
TK-511	TK-511	IFR Tank 511	VOC	11.06	6.88
			H_2S	<0.01	<0.01
			Benzene	0.16	0.09
TK-512	TK-512	IFR Tank 512	VOC	11.06	6.88
			H_2S	<0.01	<0.01
			Benzene	0.16	0.09
TK-SLOP	TK-SLOP	Slop Oil Tank	VOC	7.60	5.19
			H_2S	<0.01	<0.01
			Benzene	0.11	0.07
TK-FWP	TK-FWP	Firewater Pump Diesel Tank	VOC	0.05	<0.01

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	June 2018	Permit No.:	151335	Regulated Entity No.	RN110317666
Area Name:	TGTI Onshore Terminal			Customer Reference No.	CN605490085

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) Pounds per Hour [1]	(B) TPY [1]
FWP-1	FWP-1	Firewater Pump	VOC	0.39	0.02
			NO_X	13.36	0.67
			CO	7.45	0.37
			$PM/PM_{10}/PM_{2.5}$	0.43	0.02
			SO_2	0.01	<0.01
FUG-100	FUG-100N, FUG-100S	Fugitives at Tanks & VCU Unit	VOC	0.63	2.75
			H_2S	<0.01	<0.01
			Benzene	<0.01	0.03
FUG-200	FUG-200	Fugitives at Manifold	VOC	0.54	2.34
			H_2S	<0.01	<0.01
			Benzene	<0.01	0.02
FUG-300	FUG-300	Fugitives at Meter Skids	VOC	0.24	1.03
			H_2S	<0.01	<0.01
			Benzene	<0.01	<0.01
FUG-400	FUG-400	Fugitives at OWS	VOC	0.01	0.05
			H_2S	<0.01	<0.01
			Benzene	<0.01	<0.01

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	June 2018	Permit No.:	151335	Regulated Entity No.	RN110317666
Area Name:	TGTI Onshore Terminal			Customer Reference No.	CN605490085

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) Pounds per Hour [1]	(B) TPY [1]
VCU-TKS	VCU-TKS	Vapor Combustion Unit (VCU) for Controlled Standing Idle, Degassing, Forced Ventilation, and Refilling Activities	VOC	11.23	0.68
			NO_X	2.10	0.13
			CO	4.19	0.25
			$PM/PM_{10}/PM_{2.5}$	0.16	<0.01
			SO_2	0.04	<0.01
			H_2S	<0.01	<0.01
			Benzene	0.08	<0.01
OWS	OWS	Oil Water Separator	VOC	0.67	0.28
			H_2S	<0.01	<0.01
			Benzene	<0.01	<0.01
TKS-MSS	TKS-MSS	Sludge Removal and Vacuum Truck Venting Activities	VOC	4.05	0.17
			H_2S	<0.01	<0.01
			Benzene	0.03	<0.01
P-MSS	P-MSS	Pipeline MSS	VOC	2.22	<0.01
			H_2S	<0.01	<0.01
			Benzene	0.02	<0.01

EPN: Emission Point Number

FIN: Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	June 2018	Permit No.:	151335	Regulated Entity No.	RN110317666
Area Name:	TGTI Onshore Terminal			Customer Reference No.	CN605490085

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

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS											
1. Emission Point			4. UTM Coordinates of Emission Point			Source								
						5. Building Height (Feet)	6. Height Above Ground (Feet)	7.Stack Exit Data			8. Fugitives			
EPN (A)	FIN (B)	NAME (C)	Zone	East (Meters)	North (Meters)			Diameter (Feet) (A)	Velocity (fps) (B)	Temp. (°F) (C)	Length (ft.) (A)	Width (ft.) (B)	Axis Degrees (C)
TK-501	TK-501	IFR Tank 501	14	656,126	3,053,246		60	0.003	0.003	Ambient			
TK-502	TK-502	IFR Tank 502	14	656,286	3,053,247		60	0.003	0.003	Ambient			
TK-503	TK-503	IFR Tank 503	14	656,126	3,053,120		60	0.003	0.003	Ambient			
TK-504	TK-504	IFR Tank 504	14	656,286	3,053,121		60	0.003	0.003	Ambient			
TK-505	TK-505	IFR Tank 505	14	656,127	3,052,995		60	0.003	0.003	Ambient			
TK-506	TK-506	IFR Tank 506	14	656,287	3,052,995		60	0.003	0.003	Ambient			
TK-507	TK-507	IFR Tank 507	14	656,128	3,052,790		60	0.003	0.003	Ambient			
TK-508	TK-508	IFR Tank 508	14	656,288	3,052,791		60	0.003	0.003	Ambient			
TK-509	TK-509	IFR Tank 509	14	656,128	3,052,664		60	0.003	0.003	Ambient			
TK-510	TK-510	IFR Tank 510	14	656,288	3,052,665		60	0.003	0.003	Ambient			
TK-511	TK-511	IFR Tank 511	14	656,129	3,052,539		60	0.003	0.003	Ambient			
TK-512	TK-512	IFR Tank 512	14	656,289	3,052,539		60	0.003	0.003	Ambient			
TK-SLOP	TK-SLOP	Slop Oil Tank	14	656,207	3,052,893		60	0.003	0.003	Ambient			
TK-FWP	TK-FWP	Firewater Pump Diesel Tank	14	656,207	3,052,893		10	0.003	0.003	Ambient			
FWP-1	FWP-1	Firewater Pump	14	656,207	3,052,893		8	0.3	65.6	440.33			
FUG-100	FUG-100N, FUG-100S	Fugitives at Tanks & VCU Unit	14	656,211	3,053,050		3						
FUG-200	FUG-200	Fugitives at Manifold	14	656,216	3,052,889		3						
FUG-300	FUG-300	Fugitives at Meter Skids	14	656,007	3,052,869		3						
FUG-400	FUG-400	Fugitives at OWS	14	656,379	3,052,865		3						
VCU-TKS	VCU-TKS	Vapor Combustion Unit (VCU) for Controlled Standing Idle, Degassing, Forced Ventilation, and Refilling Activities	14	656,207	3,052,893		60	10.0	55.0	1400			
OWS	OWS	Oil Water Separator	14	656,379	3,052,865								
TKS-MSS	TKS-MSS	Sludge Removal and Vacuum Truck Venting Activities	14	656,207	3,052,893		10				232.64	232.64	
P-MSS	P-MSS	Pipeline MSS	14	656,207	3,052,893		3						

APPENDIX B: DETAILED EMISSIONS CALCULATIONS

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
Non-Rule Standard Permit Limit Comparison

Air Contaminant	Site-Wide Emission Totals			Standard Permit Limits per 6002(h).		
	Steady-state or <30 psig periodic release (lb/hr)	≥ 30 psig periodic (up to 600 hr/yr) (lb/hr)	Total (tpy)	Steady-state or <30 psig periodic release (lb/hr)	≥ 30 psig (up to 600 hr/yr) (lb/hr)	Total (tpy)
Total VOC [1]	145.23	--	95.07	--	--	250
Total crude oil or condensate VOC [1]	144.79	--	--	145	318	--
Total natural gas VOC	--	--	--	750	1635	--
Benzene [1]	2.13	--	1.25	7	15.4	10.2
H_2S [1]	3.16E-03	--	2.08E-03	10.8	9.8	47
SO_2	0.05	--	3.24E-03	93.2	--	250
NO_x	15.46	--	0.80	121	--	250
CO	11.65	--	0.63	104	--	250
PM_{10}	0.59	--	0.03	28	--	15
$PM_{2.5}$	0.59	--	0.03	28	--	15

[1] Hourly emissions include the worst-case between normal and MSS operations for storage tanks.

[2] The emergency generator is authorized under PBR 106.511; therefore,it is not included in this assessment.

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
Emissions Summary

EPN / Emission Source	VOC		NO_x		CO		PM		PM_{10}		$PM_{2.5}$		SO_2		H_2S		Benzene	
	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy
TK-501 / IFR Tank 501	11.06	6.88	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	0.16	0.09
TK-502 / IFR Tank 502	11.06	6.88	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	0.16	0.09
TK-503 / IFR Tank 503	11.06	6.88	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	0.16	0.09
TK-504 / IFR Tank 504	11.06	6.88	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	0.16	0.09
TK-505 / IFR Tank 505	11.06	6.88	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	0.16	0.09
TK-506 / IFR Tank 506	11.06	6.88	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	0.16	0.09
TK-507 / IFR Tank 507	11.06	6.88	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	0.16	0.09
TK-508 / IFR Tank 508	11.06	6.88	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	0.16	0.09
TK-509 / IFR Tank 509	11.06	6.88	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	0.16	0.09
TK-510 / IFR Tank 510	11.06	6.88	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	0.16	0.09
TK-511 / IFR Tank 511	11.06	6.88	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	0.16	0.09
TK-512 / IFR Tank 512	11.06	6.88	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	0.16	0.09
TK-SLOP / Slop Oil Tank	7.60	5.19	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	0.11	0.07
TK-FWP / Firewater Pump Diesel Tank	0.05	2.05E-04	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
FWP-1 / Firewater Pump	0.39	0.02	13.36	0.67	7.45	0.37	0.43	0.02	0.43	0.02	0.43	0.02	0.01	<0.01	--	--	--	--
FUG-100 / Fugitives at Tanks & VCU Unit	0.63	2.75	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	<0.01	0.03
FUG-200 / Fugitives at Manifold	0.54	2.34	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	<0.01	0.02
FUG-300 / Fugitives at Meter Skids	0.24	1.03	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	<0.01	<0.01
FUG-400 / Fugitives at OWS	0.01	0.05	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	<0.01	<0.01
VCU-TKS / Vapor Combustion Unit (VCU) for Controlled Standing Idle, Degassing, Forced Ventilation, and Refilling Activities	11.23	0.68	2.10	0.13	4.19	0.25	0.16	<0.01	0.16	<0.01	0.16	<0.01	0.04	<0.01	<0.01	<0.01	0.08	<0.01
TKS-MSS / Sludge Removal and Vacuum Truck Venting Activities	4.05	0.17	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	0.03	<0.01
P-MSS / Pipeline MSS	2.22	1.11E-03	--	--	--	--	--	--	--	--	--	--	--	--	<0.01	<0.01	0.02	<0.01
Oil Water Separator (OWS)	0.67	0.28													<0.01	<0.01	<0.01	<0.01
Emergency Generator (PBR 106.511)[1]	2.87	0.14	6.88	0.34	11.46	0.57	0.84	0.04	0.84	0.04	0.84	0.04	0.03	<0.01			<0.01	<0.01
Totals		**95.22**		**1.14**		**1.20**		**0.07**		**0.07**		**0.07**		**<0.01**		**<0.01**		**1.25**
Maximum Operating Schedule:			**Hours/Day**	24	**Days/Week**	7				**Weeks/Year**	52		**Hours/Year**	8760				

[1] The emergency generator is authorized under PBR 106.511 and is not included as part of this Non-Rule Standard Permit.

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
Internal Floating Roof Storage Tank Emissions Calculations

Emissions from Internal Floating Roof Storage Tanks [1]

EPN	Tank Type	Tank Content	Annual Throughput [2]	Hourly Throughput [3]	TVP [2]	VOC Standing Loss [4]		VOC Withdrawal Loss		Hourly VOC Emissions [5]	Annual VOC Emissions	Benzene Standing Loss		Benzene Withdrawal Loss		Hourly Benzene Emissions [6]	Annual Benzene Emissions [6]	Hourly H_2S Emissions [7],[9]	Annual H_2S Emissions [8],[10]
			(bbl/yr/tank)	(bbl/hr)	(psia)	(lb/yr)	(lb/hr)	(lb/yr)	(lb/hr)	(lb/hr)	(tpy)	(lb/yr)	(lb/hr)	(lb/yr)	(lb/hr)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
TK-501	Internal Floating Roof	Crude Oil	55,000,000	60,000	11.00	4,296	0.74	9,464	10.32	11.06	6.88	41.33	7.08E-03	144.13	0.16	0.16	0.09	2.42E-04	1.50E-04
TK-502	Internal Floating Roof	Crude Oil	55,000,000	60,000	11.00	4,296	0.74	9,464	10.32	11.06	6.88	41.33	7.08E-03	144.13	0.16	0.16	0.09	2.42E-04	1.50E-04
TK-503	Internal Floating Roof	Crude Oil	55,000,000	60,000	11.00	4,296	0.74	9,464	10.32	11.06	6.88	41.33	7.08E-03	144.13	0.16	0.16	0.09	2.42E-04	1.50E-04
TK-504	Internal Floating Roof	Crude Oil	55,000,000	60,000	11.00	4,296	0.74	9,464	10.32	11.06	6.88	41.33	7.08E-03	144.13	0.16	0.16	0.09	2.42E-04	1.50E-04
TK-505	Internal Floating Roof	Crude Oil	55,000,000	60,000	11.00	4,296	0.74	9,464	10.32	11.06	6.88	41.33	7.08E-03	144.13	0.16	0.16	0.09	2.42E-04	1.50E-04
TK-506	Internal Floating Roof	Crude Oil	55,000,000	60,000	11.00	4,296	0.74	9,464	10.32	11.06	6.88	41.33	7.08E-03	144.13	0.16	0.16	0.09	2.42E-04	1.50E-04
TK-507	Internal Floating Roof	Crude Oil	55,000,000	60,000	11.00	4,296	0.74	9,464	10.32	11.06	6.88	41.33	7.08E-03	144.13	0.16	0.16	0.09	2.42E-04	1.50E-04
TK-508	Internal Floating Roof	Crude Oil	55,000,000	60,000	11.00	4,296	0.74	9,464	10.32	11.06	6.88	41.33	7.08E-03	144.13	0.16	0.16	0.09	2.42E-04	1.50E-04
TK-509	Internal Floating Roof	Crude Oil	55,000,000	60,000	11.00	4,296	0.74	9,464	10.32	11.06	6.88	41.33	7.08E-03	144.13	0.16	0.16	0.09	2.42E-04	1.50E-04
TK-510	Internal Floating Roof	Crude Oil	55,000,000	60,000	11.00	4,296	0.74	9,464	10.32	11.06	6.88	41.33	7.08E-03	144.13	0.16	0.16	0.09	2.42E-04	1.50E-04
TK-511	Internal Floating Roof	Crude Oil	55,000,000	60,000	11.00	4,296	0.74	9,464	10.32	11.06	6.88	41.33	7.08E-03	144.13	0.16	0.16	0.09	2.42E-04	1.50E-04
TK-512	Internal Floating Roof	Crude Oil	55,000,000	60,000	11.00	4,296	0.74	9,464	10.32	11.06	6.88	41.33	7.08E-03	144.13	0.16	0.16	0.09	2.42E-04	1.50E-04
TK-SLOP	Internal Floating Roof	Slop Oil Tank	27,500,000	23,000	11.00	1,630	0.28	8,748	7.32	7.60	5.19	15.68	2.68E-03	133.22	0.11	0.11	0.07	1.66E-04	1.13E-04

Reference:

[1] Emissions calculated using EPA's TANKS 4.0.9d software

[2] Based on Revised Project Design Document provided by TGTI to Trinity Consultants on February 22, 2018.

[3] Based on Revised Project Design Document provided by TGTI to Trinity Consultants on February 22, 2018.

[4] Based on Updated fittings design provided to TGTI by Trinity in March 2018.

[5] Vapor pressure values remain constant for both hourly and annual calculations. Per TCEQ's 2018 guidance "Short-term Emissions from Floating Roof Storage Tanks" (APDG6419v1, Released 02/18), the hourly standing emissions are calculated based on a product factor of 0.6. Th hourly VOC and benzene emissions are the summation of respective standing and withdrawal losses of VOC and benzene.

$$\text{Hourly Standing Emissions (lb/hr)} = \frac{4{,}295.77\ \text{lb}}{\text{yr}} \cdot \frac{0.6}{0.4} \cdot \frac{\text{yr}}{8{,}760\ \text{hr}} = 0.74\ \text{lb/hr}$$

$$\text{Hourly Withdrawal Emissions (lb/hr)} = \frac{9{,}464.40\ \text{lb}}{\text{yr}} \cdot \frac{60{,}000\ \text{bbl}}{\text{hr}} \cdot \frac{\text{yr}}{55{,}000{,}000\ \text{bbl}} = 10.32\ \text{lb/hr}$$

$$\text{Hourly VOC Emissions (lb/hr)} = 0.74\ \text{lb/hr} + 10.32\ \text{lb/hr} = 11.06\ \text{lb/hr}$$

[6] Maximum and average benzene in crude/condensate liquid is assumed to be 1.50%

[7] Maximum ratio of H_2S in Crude/Condensate is assumed to be 2.19E-05

[8] Average ratio of H_2S in Crude/Condensate is assumed to be 2.19E-05

[9] H_2S Hourly Emissions (lb/hr) = Max H_2S Mass Ratio (lb H_2S/lb VOC) x Uncontrolled VOC Emissions (lb/hr)

$$H_2S\ \text{Hourly Emissions (lb/hr)} = \frac{2.19\text{E-}05\ \text{lb H2S}}{\text{lb VOC}} \cdot \frac{11.06\ \text{lb}}{\text{hr}} = 2.42\text{E-}04\ \text{lb/hr}$$

[10] H_2S Annual Emissions (tpy) = Avg H_2S Mass Ratio (lb H_2S/lb VOC) x Uncontrolled VOC Emissions (tpy)

$$H_2S\ \text{Annual Emissions (tpy)} = \frac{2.19\text{E-}05\ \text{lb H2S}}{\text{lb VOC}} \cdot 6.88\ \text{tpy} = 1.50\text{E-}4\ \text{tpy}$$

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
Internal Floating Roof Storage Tank Emissions Calculations

Emissions from Internal Floating Roof Storage Tanks [1]

EPN	Tank Type	Tank Content	Annual Throughput [2]	Hourly Throughput [3]	Hourly TVP [2]	Annual TVP [2]	VOC Standing Loss [4]		VOC Withdrawal Loss		Hourly VOC Emissions [5]	Annual VOC Emissions	Benzene Standing Loss [6]		Benzene Withdrawal Loss		Hourly Benzene Emissions [6]	Annual Benzene Emissions [6]	Hourly H_2S Emissions [7][9]	Annual H_2S Emissions [8][10]
			(bbl/yr/tank)	(bbl/hr)	(psia)	(psia)	(lb/yr)	(lb/hr)	(lb/yr)	(lb/hr)	(lb/hr)	(tpy)	(lb/yr)	(lb/hr)	(lb/yr)	(lb/hr)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
TK-501	Internal Floating Roof	Condensate	55,000,000	60,000	11.00	9.25	10,201	2.29	1,872	2.04	4.34	6.04	41.82	8.17E-03	28.51	0.03	0.04	0.04	7.30E-05	1.02E-04
TK-502	Internal Floating Roof	Condensate	55,000,000	60,000	11.00	9.25	10,201	2.29	1,872	2.04	4.34	6.04	41.82	8.23E-03	28.51	0.03	0.04	0.04	7.30E-05	1.02E-04
TK-503	Internal Floating Roof	Condensate	55,000,000	60,000	11.00	9.25	10,201	2.29	1,872	2.04	4.34	6.04	41.82	8.23E-03	28.51	0.03	0.04	0.04	7.30E-05	1.02E-04
TK-504	Internal Floating Roof	Condensate	55,000,000	60,000	11.00	9.25	10,201	2.29	1,872	2.04	4.34	6.04	41.82	8.23E-03	28.51	0.03	0.04	0.04	7.30E-05	1.02E-04
TK-505	Internal Floating Roof	Condensate	55,000,000	60,000	11.00	9.25	10,201	2.29	1,872	2.04	4.34	6.04	41.82	8.23E-03	28.51	0.03	0.04	0.04	7.30E-05	1.02E-04
TK-506	Internal Floating Roof	Condensate	55,000,000	60,000	11.00	9.25	10,201	2.29	1,872	2.04	4.34	6.04	41.82	8.23E-03	28.51	0.03	0.04	0.04	7.30E-05	1.02E-04
TK-507	Internal Floating Roof	Condensate	55,000,000	60,000	11.00	9.25	10,201	2.29	1,872	2.04	4.34	6.04	41.82	8.23E-03	28.51	0.03	0.04	0.04	7.30E-05	1.02E-04
TK-508	Internal Floating Roof	Condensate	55,000,000	60,000	11.00	9.25	10,201	2.29	1,872	2.04	4.34	6.04	41.82	8.23E-03	28.51	0.03	0.04	0.04	7.30E-05	1.02E-04
TK-509	Internal Floating Roof	Condensate	55,000,000	60,000	11.00	9.25	10,201	2.29	1,872	2.04	4.34	6.04	41.82	8.23E-03	28.51	0.03	0.04	0.04	7.30E-05	1.02E-04
TK-510	Internal Floating Roof	Condensate	55,000,000	60,000	11.00	9.25	10,201	2.29	1,872	2.04	4.34	6.04	41.82	8.23E-03	28.51	0.03	0.04	0.04	7.30E-05	1.02E-04
TK-511	Internal Floating Roof	Condensate	55,000,000	60,000	11.00	9.25	10,201	2.29	1,872	2.04	4.34	6.04	41.82	8.23E-03	28.51	0.03	0.04	0.04	7.30E-05	1.02E-04
TK-512	Internal Floating Roof	Condensate	55,000,000	60,000	11.00	9.25	10,201	2.29	1,872	2.04	4.34	6.04	41.82	8.23E-03	28.51	0.03	0.04	0.04	7.30E-05	1.02E-04
TK-SLOP	Internal Floating Roof	Slop Oil Tank	27,500,000	23,000	11.00	9.25	3,869	0.87	1,730	1.45	2.32	2.80	15.86	3.10E-03	26.35	0.02	0.03	0.02	3.90E-05	4.71E-05

Reference:

[1] Emissions calculated using EPA's TANKS 4.0.9d software

[2] Based on Revised Project Design Document provided by TGTI to Trinity Consultants on February 22, 2018.

[3] Based on Revised Project Design Document provided by TGTI to Trinity Consultants on February 22, 2018.

[4] Based on Updated fittings design provided to TGTI by Trinity in March 2018.

[5] Vapor pressure values remain constant for both hourly and annual calculations. Per TCEQ's 2018 guidance "Short-term Emissions from Floating Roof Storage Tanks" (APDG6419v1, Released 02/18), the hourly standing emissions are calculated based on a product factor of 0.6. Th hourly VOC emissions are the summation of standing and withdrawal losses. The annual emissions of condensate-gasoline are calculated using RVP of 13.5. The hourly emissions are calculated using condensate-gasoline TVP of 11 psia to be conservative.

$$\text{Hourly Standing Emissions (lb/hr)} = \frac{10{,}200.70\ \text{lb}}{\text{yr}} \cdot \frac{0.6}{0.4} \cdot \frac{\text{yr}}{8{,}760\ \text{hr}} = 2.29\ \text{lb/hr}$$

$$\text{Hourly Withdrawal Emissions (lb/hr)} = \frac{1{,}701.76\ \text{lb}}{\text{yr}} \cdot \frac{60{,}000\ \text{bbl}}{\text{hr}} \cdot \frac{\text{yr}}{55{,}000{,}000\ \text{bbl}} = 2.04\ \text{lb/hr}$$

Hourly VOC Emissions (lb/hr) = 2.29 lb/hr + 2.04 lb/hr = 4.34 lb/hr

[6] Maximum and average benzene in crude/condensate liquid is assumed to be 1.50%

[7] Maximum ratio of H_2S in Crude/Condensate is assumed to be 1.68E-05 lb H_2S/lb VOC

[8] Average ratio of H_2S in Crude/Condensate is assumed to be 1.68E-05 lb H_2S/lb VOC

[9] H_2S Hourly Emissions (lb/hr) = Max H_2S Mass Ratio (lb H_2S/lb VOC) x Uncontrolled VOC Emissions (lb/hr)

$$H_2S\ \text{Hourly Emissions (lb/hr)} = \frac{1.68\text{E-05 lb H2S}}{\text{lb VOC}} \cdot \frac{4.34\ \text{lb}}{\text{hr}} = 7.30\text{E-05 lb/hr}$$

[10] H_2S Annual Emissions (tpy) = Avg H_2S Mass Ratio (lb H_2S/lb VOC) x Uncontrolled VOC Emissions (tpy)

$$H_2S\ \text{Annual Emissions (tpy)} = \frac{1.68\text{E-05 lb H2S}}{\text{lb VOC}} \cdot \frac{6.04\ \text{tpy}}{} = 1.02\text{E-4 tpy}$$

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
EPN TK-FWP / FIN TK-FWP
Diesel Storage Tank Emissions Calculations

EPN	FIN	Source Name	Product	Tank Type	Max Fill Rate[1] (gal/hr)	Annual Throughput (gal/yr)	Standing Loss (lb/yr)	Withdrawal Loss (lb/yr)	Vapor Molecular Weight (M_V)[2] (lb/lb-mole)	Maximum Daily Liquid Surface Temperature[2] (°R)	Vapor Pressure at Maximum Liquid Surface Temperature (P_{VA}) (psia)	Ideal Gas Constant (gal Psi lb-mol^{-1} °R^{-1})	Hourly VOC Emissions[4] (lb/hr)	Annual VOC Emissions[5] (tpy)
TK-FWP	TK-FWP	Firewater Pump Diesel Tank	Diesel	Horizontal	1,500	1,200	0.04	0.37	130.00	554.67	0.012	80.27	0.05	2.05E-04
												Maximum VOC Emissions	**0.05**	**2.05E-04**

[1] The maximum fill rate is based on filling a 1,500 gallon horizontal storage tank.
[2] Vapor pressures, vapor molecular weights and temperatures of the products loaded based on products' physical properties.
[3] Hourly emissions are calculated based on TCEQ guidance, *Estimating Short Term Emission Rates from Tanks (APDG 6250v1, Revised 02/18)* . Methodology is detailed below.
[4] Annual emissions were calculated using EPA's TANKS 4.0.9d software summing both withdrawal and standing losses.

Maximum Short-Term Emission Formula for Fixed Roof Tanks

$$L_{MAX} = \frac{M_V P_{VA}}{RT} FR_M$$

Where

L_{MAX}= Maximum short term emission rate, lbs/hour
M_v= vapor molecular weight, lb/lb-mole
P_{VA}= VP at max daily liquid surface temperature, psia
FR_M= Maximum filling rate, gal/hr
R= Ideal gas constant, (psia gal)/(lb-mol °R)
T= Max daily liquid surface temperature, °R

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
EPN FUG-100 / FINS FUG-100N, FUG-100S
Tanks & Vapor Combustion Unit Unit Fugitives Emissions Calculations

Component Type	Oil & Gas Emission Factor Type	Fugitive Emission Factor [1]	Total Number of Components [2]	LDAR Program	Control Efficiency [3]	VOC Emissions [4],[5],[6]		Benzene Emissions [7],[8]		H_2S Emissions [9],[10]	
	(lb/hr)	(lb/hr/ component)			(%)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Valves											
Gas / Vapor	Gas	0.00992	108	28M	75%	0.27	1.18	2.55E-03	0.01	5.88E-06	2.57E-05
Light Liquid	Light Oil > 20° API	0.0055	13	28M	75%	0.02	0.08	1.70E-04	7.44E-04	3.91E-07	1.71E-06
Heavy Liquid	Heavy Oil < 20° API	0.0000185	0	28M	0%	0	0	0	0	0	0
Pump Seals											
Gas/Vapor	Gas	0.00529	0	28M	0%	0	0	0	0	0	0
Light Liquid	Light Oil > 20° API	0.02866	0	28M	75%	0	0	0	0	0	0
Heavy Liquid	Heavy Oil < 20° API	0.00113	0	28M	0%	0	0	0	0	0	0
Flanges											
Gas / Vapor	Gas	0.00086	549	28M	30%	0.33	1.45	3.14E-03	0.01	7.23E-06	3.17E-05
Light Liquid	Light Oil > 20° API	0.000243	65	28M	30%	0.01	0.05	1.05E-04	4.60E-04	2.42E-07	1.06E-06
Heavy Liquid	Heavy Oil < 20° API	0.00000086	0	28M	30%	0	0	0	0	0	0
Compressor Seals											
Gas / Vapor	Gas	0.0194	0	28M	75%	0	0	0	0	0	0
Relief Valves											
Gas / Vapor	Gas	0.0194	0	28M	75%	0	0	0	0	0	0
					Total VOC	**0.63**	**2.75**	**5.97E-03**	**0.03**	**1.37E-05**	**6.02E-05**

References:

[1] Emission Factors were obtained from *Table 4. Average Emission Factors - Petroleum Industry* (Oil & Gas Production Operations) of TCEQ's Addendum to RG-360A, Emission Factors for Equipment Leak Fugitives Components, January 2008.

[2] Component Count is based on Revised Project Design Document provided by Lloyd Engineering, Inc. to TGTI on September 15, 2017.

[3] Based on TCEQ control efficiency guidance for 28M Leak Detection and Repair Program.

[4] Fugitive emissions are conservatively estimated to be 100% VOC.

[5] Annual hours of operation are 8,760 hours/year

[6] Sample calculation - Valves (Light Liquid)

$$\text{Hourly VOC Emissions (lb/hr)} = \frac{13\ \text{component(s)}}{} \cdot \frac{0.0055\ \text{lb/hr}}{\text{component}} \cdot \frac{100 - 75\%}{\text{control}} = 0.02\ \text{lb/hr}$$

$$\text{Annual VOC Emissions (tpy)} = \frac{0.02\ \text{lb}}{\text{hr}} \cdot \frac{8{,}760\ \text{hrs}}{\text{yr}} \cdot \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = 0.08\ \text{tpy}$$

[7] Maximum benzene in crude/condensate vapor is assumed to be 0.95%

[8] Hourly Benzene Emissions (lb/hr) = % Benzene in Crude Oil/Condensate x Hourly VOC Emissions (lb/hr)

$$\text{Hourly Benzene Emissions (lb/hr)} = \frac{0.95\%}{} \cdot \frac{0.27\ \text{lb}}{\text{hr}} = 2.55\text{E-03 lb/hr}$$

Annual Benzene Emissions (tpy) = Hourly Benzene Emissions (lb/hr) x 8,760 hrs/yr x (1 ton/2,000 lb)

$$\text{Annual Benzene Emissions (tpy)} = \frac{2.55\text{E-03 lb}}{\text{hr}} \cdot \frac{8{,}760\ \text{hrs}}{\text{yr}} \cdot \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = 1.12\text{E-02 tpy}$$

[9] Maximum ratio of H_2S in Crude/Condensate is assumed to be 2.19E-05 lb H_2S/lb VOC

[10] Hourly H_2S Emissions (lb/hr) = Maximum Ratio of H_2S in Crude/Condensate (lb H_2S/lb VOC) x Hourly VOC Emissions (lb/hr)

$$\text{Hourly } H_2S \text{ Emissions (lb/hr)} = \frac{2.19\text{E-05 lb H2S}}{\text{lb VOC}} \cdot \frac{0.27\ \text{lb}}{\text{hr}} = 5.88\text{E-06 lb/hr}$$

Annual H_2S Emissions (tpy) = Hourly H_2S Emissions (lb/hr) x 8,760 hrs/yr x (1 ton/2,000 lb)

$$\text{Annual } H_2S \text{ Emissions (tpy)} = \frac{5.88\text{E-06 lb}}{\text{hr}} \cdot \frac{8{,}760\ \text{hrs}}{\text{yr}} \cdot \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = 2.57\text{E-05 tpy}$$

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
EPN FUG-200 / FIN FUG-200
Manifold Fugitives Emissions Calculations

Component Type	Oil & Gas Emission Factor Type	Fugitive Emission Factor [1]	Total Number of Components [2]	LDAR Program	Control Efficiency [3]	VOC Emissions [4],[5],[6]		Benzene Emissions [7],[8]		H_2S Emissions [9],[10]	
	(lb/hr)	(lb/hr/ component)			(%)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Valves											
Gas / Vapor	Gas	0.00992	0	28M	75%	0	0	0	0	0	0
Light Liquid	Light Oil > 20° API	0.0055	282	28M	75%	0.39	1.70	3.68E-03	0.02	8.48E-06	3.71E-05
Heavy Liquid	Heavy Oil < 20° API	0.0000185	0	28M	0%	0	0	0	0	0	0
Pump Seals											
Gas/Vapor	Gas	0.00529	0	28M	0%	0	0	0	0	0	0
Light Liquid	Light Oil > 20° API	0.02866	8	28M	75%	0.05	0.24	5.11E-04	2.24E-03	1.18E-06	5.15E-06
Heavy Liquid	Heavy Oil < 20° API	0.00113	0	28M	0%	0	0	0	0	0	0
Flanges											
Gas / Vapor	Gas	0.00086	0	28M	30%	0	0	0	0	0	0
Light Liquid	Light Oil > 20° API	0.000243	551	28M	30%	0.09	0.41	8.90E-04	3.90E-03	2.05E-06	8.97E-06
Heavy Liquid	Heavy Oil < 20° API	0.00000086	0	28M	30%	0	0	0	0	0	0
Compressor Seals											
Gas / Vapor	Gas	0.0194	0	28M	75%	0	0	0	0	0	0
Relief Valves											
Gas / Vapor	Gas	0.0194	0	28M	75%	0	0	0	0	0	0
					Total VOC	**0.54**	**2.34**	**5.08E-03**	**0.02**	**1.17E-05**	**5.13E-05**

References:

[1] Emission Factors were obtained from *Table 4. Average Emission Factors - Petroleum Industry* (Oil & Gas Production Operations) of TCEQ's Addendum to RG-360A, Emission Factors for Equipment Leak Fugitives Components, January 2008.

[2] Component Count is based on Revised Project Design Document provided by Lloyd Engineering, Inc. to TGTI on September 15, 2017.

[3] Based on TCEQ control efficiency guidance for 28M Leak Detection and Repair Program.

[4] Fugitive emissions are conservatively estimated to be 100% VOC.

[5] Annual hours of operation are 8,760 hours/year

[6] Sample calculation - Valves (Light Liquid)

$$\text{Hourly VOC Emissions (lb/hr)} = \frac{282 \text{ component(s)}}{} \cdot \frac{0.0055 \text{ lb/hr}}{\text{component}} \cdot \frac{100 - 75\%}{\text{control}} = 0.39 \text{ lb/hr}$$

$$\text{Annual VOC Emissions (tpy)} = \frac{0.39 \text{ lb}}{\text{hr}} \cdot \frac{8{,}760 \text{ hrs}}{\text{yr}} \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 1.70 \text{ tpy}$$

[7] Maximum benzene in crude/condensate vapor is assumed to be 0.95%

[8] Hourly Benzene Emissions (lb/hr) = % Benzene in Crude Oil/Condensate x Hourly VOC Emissions (lb/hr)

$$\text{Hourly Benzene Emissions (lb/hr)} = \frac{0.95\%}{} \cdot \frac{0.38775 \text{ lb}}{\text{hr}} = 3.68\text{E-03 lb/hr}$$

Annual Benzene Emissions (tpy) = Hourly Benzene Emissions (lb/hr) x 8,760 hrs/yr x (1 ton/2,000 lb)

$$\text{Annual Benzene Emissions (tpy)} = \frac{3.68\text{E-03 lb}}{\text{hr}} \cdot \frac{8{,}760 \text{ hrs}}{\text{yr}} \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 1.61\text{E-02 tpy}$$

[9] Maximum ratio of H_2S in Crude/Condensate is assumed to be 2.19E-05 lb H_2S/lb VOC

[10] Hourly H_2S Emissions (lb/hr) = Maximum Ratio of H_2S in Crude/Condensate (lb H_2S/lb VOC) x Hourly VOC Emissions (lb/hr)

$$\text{Hourly } H_2S \text{ Emissions (lb/hr)} = \frac{2.19\text{E-05 lb H2S}}{\text{lb VOC}} \cdot \frac{0.38775 \text{ lb}}{\text{hr}} = 8.48\text{E-06 lb/hr}$$

Annual H_2S Emissions (tpy) = Hourly H_2S Emissions (lb/hr) x 8,760 hrs/yr x (1 ton/2,000 lb)

$$\text{Annual } H_2S \text{ Emissions (tpy)} = \frac{8.48\text{E-06 lb}}{\text{hr}} \cdot \frac{8{,}760 \text{ hrs}}{\text{yr}} \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 3.71\text{E-05 tpy}$$

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
EPN FUG-300 / FIN FUG-300
Meter Skids Fugitives Emissions Calculations

Component Type	Oil & Gas Emission Factor Type	Fugitive Emission Factor [1]	Total Number of Components [2]	LDAR Program	Control Efficiency [3]	VOC Emissions [4],[5],[6]		Benzene Emissions [7],[8]		H_2S Emissions [9],[10]	
		(lb/hr/ component)			(%)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Valves											
Gas / Vapor	Gas	0.00992	0	28M	75%	0	0	0	0	0	0
Light Liquid	Light Oil > 20° API	0.0055	149	28M	75%	0.20	0.89	1.94E-03	8.50E-03	4.47E-06	1.96E-05
Heavy Liquid	Heavy Oil < 20° API	0.0000185	0	28M	0%	0	0	0	0	0	0
Pump Seals											
Gas/Vapor	Gas	0.00529	0	28M	0%	0	0	0	0	0	0
Light Liquid	Light Oil > 20° API	0.02866	0	28M	75%	0.00E00	0.00E00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heavy Liquid	Heavy Oil < 20° API	0.00113	0	28M	0%	0	0	0	0	0	0
Flanges											
Gas / Vapor	Gas	0.00086	0	28M	30%	0	0	0	0	0	0
Light Liquid	Light Oil > 20° API	0.000243	183	28M	30%	0.03	0.14	2.96E-04	1.30E-03	6.81E-07	2.98E-06
Heavy Liquid	Heavy Oil < 20° API	0.00000086	0	28M	30%	0	0	0	0	0	0
Compressor Seals											
Gas / Vapor	Gas	0.0194	0	28M	75%	0	0	0	0	0	0
Relief Valves											
Gas / Vapor	Gas	0.0194	0	28M	75%	0	0	0	0	0	0
					Total VOC	**0.24**	**1.03**	**2.24E-03**	**9.79E-03**	**5.15E-06**	**2.25E-05**

References:

[1] Emission Factors were obtained from *Table 4. Average Emission Factors - Petroleum Industry* (Oil & Gas Production Operations) of TCEQ's Addendum to RG-360A, Emission Factors for Equipment Leak Fugitives Components, January 2008.

[2] Component Count is based on Revised Project Design Document provided by Lloyd Engineering, Inc. to TGTI on September 15, 2017.

[3] Based on TCEQ control efficiency guidance for 28M Leak Detection and Repair Program.

[4] Fugitive emissions are conservatively estimated to be 100% VOC.

[5] Annual hours of operation are 8,760 hours/year

[6] Sample calculation - Valves (Light Liquid)

$$\text{Maximum Hourly Emissions: } \frac{148.5 \text{ component(s)}}{} \cdot \frac{0.0055 \text{ lb/hr}}{\text{component}} \cdot \frac{100 - 75\%}{\text{control}} = 0.20 \text{ lb/hr}$$

$$\text{Annual Emissions: } \frac{0.20 \text{ lb}}{\text{hr}} \cdot \frac{8{,}760 \text{ hrs}}{\text{yr}} \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 0.89 \text{ tpy}$$

[7] Maximum benzene in crude/condensate vapor is assumed to be 0.95%

[8] Hourly Benzene Emissions (lb/hr) = % Benzene in Crude Oil/Condensate x Hourly VOC Emissions (lb/hr)

$$\text{Hourly Benzene Emissions (lb/hr)} = \frac{0.95\%}{} \cdot \frac{0.2041875 \text{ lb}}{\text{hr}} = 1.94\text{E-03 lb/hr}$$

Annual Benzene Emissions (tpy) = Hourly Benzene Emissions (lb/hr) x 8,760 hrs/yr x (1 ton/2,000 lb)

$$\text{Annual Benzene Emissions (tpy)} = \frac{1.94\text{E-03 lb}}{\text{hr}} \cdot \frac{8{,}760 \text{ hrs}}{\text{yr}} \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 8.50\text{E-03 tpy}$$

[9] Maximum ratio of H_2S in Crude/Condensate is assumed to be 2.19E-05 lb H_2S/lb VOC

[10] Hourly H_2S Emissions (lb/hr) = Maximum Ratio of H_2S in Crude/Condensate (lb H_2S/lb VOC) x Hourly VOC Emissions (lb/hr)

$$\text{Hourly } H_2S \text{ Emissions (lb/hr)} = \frac{2.19\text{E-05 lb H2S}}{\text{lb VOC}} \cdot \frac{0.2041875 \text{ lb}}{\text{hr}} = 4.47\text{E-06 lb/hr}$$

Annual H_2S Emissions (tpy) = Hourly H_2S Emissions (lb/hr) x 8,760 hrs/yr x (1 ton/2,000 lb)

$$\text{Annual } H_2S \text{ Emissions (tpy)} = \frac{4.47\text{E-06 lb}}{\text{hr}} \cdot \frac{8{,}760 \text{ hrs}}{\text{yr}} \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 1.96\text{E-05 tpy}$$

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
EPN FUG-400 / FIN FUG-400
OWS Fugitives Emissions Calculations

Component Type	Oil & Gas Emission Factor Type	Fugitive Emission Factor [1]	Total Number of Components [2]	LDAR Program	Control Efficiency [3]	VOC Emissions [4],[5],[6]		Benzene Emissions [7],[8]		H_2S Emissions [9],[10]	
		(lb/hr/ component)			(%)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Valves											
Gas / Vapor	Gas	0.00992	0	28M	75%	0	0	0	0	0	0
Light Liquid	Light Oil > 20° API	0.0055	2	28M	75%	2.75E-03	0.01	2.61E-05	1.14E-04	6.02E-08	2.63E-07
Heavy Liquid	Heavy Oil < 20° API	0.0000185	0	28M	0%	0	0	0	0	0	0
Pump Seals											
Gas/Vapor	Gas	0.00529	0	28M	0%	0	0	0	0	0	0
Light Liquid	Light Oil > 20° API	0.02866	1	28M	75%	7.17E-03	0.03	6.81E-05	2.98E-04	1.57E-07	6.86E-07
Heavy Liquid	Heavy Oil < 20° API	0.00113	0	28M	0%	0	0	0	0	0	0
Flanges											
Gas / Vapor	Gas	0.00086	0	28M	30%	0	0	0	0	0	0
Light Liquid	Light Oil > 20° API	0.000243	5	28M	30%	8.51E-04	3.73E-03	8.08E-06	3.54E-05	1.86E-08	8.15E-08
Heavy Liquid	Heavy Oil < 20° API	0.00000086	0	28M	30%	0	0	0	0	0	0
Compressor Seals											
Gas / Vapor	Gas	0.0194	0	28M	75%	0	0	0	0	0	0
Relief Valves											
Gas / Vapor	Gas	0.0194	0	28M	75%	0	0	0	0	0	0
					Total VOC	**0.01**	**0.05**	**1.02E-04**	**4.48E-04**	**2.35E-07**	**1.03E-06**

References:

[1] Emission Factors were obtained from *Table 4. Average Emission Factors - Petroleum Industry* (Oil & Gas Production Operations) of TCEQ's Addendum to RG-360A, Emission Factors for Equipment Leak Fugitives Components, January 2008.

[2] Component Count is based on Revised Project Design Document provided by Lloyd Engineering, Inc. to TGTI on June 12, 2018.

[3] Based on TCEQ control efficiency guidance for 28M Leak Detection and Repair Program.

[4] Fugitive emissions are conservatively estimated to be 100% VOC.

[5] Annual hours of operation are 8,760 hours/year

[6] Sample calculation - Valves (Light Liquid)

$$\text{Maximum Hourly Emissions: } \frac{2 \text{ component(s)}}{} \cdot \frac{0.0055 \text{ lb/hr}}{\text{component}} \cdot \frac{100 - 75\%}{\text{control}} = 0.00 \text{ lb/hr}$$

$$\text{Annual Emissions: } \frac{0.00 \text{ lb}}{\text{hr}} \cdot \frac{8{,}760 \text{ hrs}}{\text{yr}} \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 0.01 \text{ tpy}$$

[7] Maximum benzene in crude/condensate vapor is assumed to be 0.95%

[8] Hourly Benzene Emissions (lb/hr) = % Benzene in Crude Oil/Condensate x Hourly VOC Emissions (lb/hr)

$$\text{Hourly Benzene Emissions (lb/hr)} = \frac{0.95\%}{} \cdot \frac{0.00275 \text{ lb}}{\text{hr}} = 2.61\text{E-05 lb/hr}$$

Annual Benzene Emissions (tpy) = Hourly Benzene Emissions (lb/hr) x 8,760 hrs/yr x (1 ton/2,000 lb)

$$\text{Annual Benzene Emissions (tpy)} = \frac{2.61\text{E-05 lb}}{\text{hr}} \cdot \frac{8{,}760 \text{ hrs}}{\text{yr}} \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 1.14\text{E-04 tpy}$$

[9] Maximum ratio of H_2S in Crude/Condensate is assumed to be 2.19E-05 lb H_2S/lb VOC

[10] Hourly H_2S Emissions (lb/hr) = Maximum Ratio of H_2S in Crude/Condensate (lb H_2S/lb VOC) x Hourly VOC Emissions (lb/hr)

$$\text{Hourly } H_2S \text{ Emissions (lb/hr)} = \frac{2.19\text{E-05 lb H2S}}{\text{lb VOC}} \cdot \frac{0.00275 \text{ lb}}{\text{hr}} = 6.02\text{E-08 lb/hr}$$

Annual H_2S Emissions (tpy) = Hourly H_2S Emissions (lb/hr) x 8,760 hrs/yr x (1 ton/2,000 lb)

$$\text{Annual } H_2S \text{ Emissions (tpy)} = \frac{6.02\text{E-08 lb}}{\text{hr}} \cdot \frac{8{,}760 \text{ hrs}}{\text{yr}} \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 2.63\text{E-07 tpy}$$

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
EPN FWP-1 / FIN FWP-1
Firewater Pump Engine Emissions Calculations

EPN	FWP-1		
Engine Rating	=	969.4	kW
		1,300	HP
Operating Time	=	100	hrs/yr
Fuel Type [3]	=	ULSD	

Pollutant	Emission Factor		Maximum Emissions	Annual Emissions
	Value	Units	(lb/hr)	(tons/yr)
PM [1]	0.15	g/hp-hr	0.43	0.02
PM_{10} [1]	0.15	g/hp-hr	0.43	0.02
$PM_{2.5}$ [1]	0.15	g/hp-hr	0.43	0.02
NOx [1], [2]	4.66	g/hp-hr	13.36	0.67
SO_2 [3]	1.06E-05	lb/hp-hr	1.38E-02	6.88E-04
CO [1]	2.60	g/hp-hr	7.45	0.37
VOC [1],[2]	0.14	g/hp-hr	0.39	0.02

[1] Based on Table 4 of 40 CFR 60 NSPS IIII for Firewater pump engines greater than 750 hp and constructed after 2008.

[2] Based on AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and All Stationary Dual-Fuel Engines (October 1996). Per footnote b of Table 3.3-1, all PM is assumed to be < 1 um, therefore, assumed $PM_{2.5} = PM_{10} = PM$.

[3] TGTI is proposing the use of Ultra Low Sulfur Diesel (ULSD) for the firewater pump engine. Therefore, emissions have been calculated based on a maximum sulfur content of 15 ppm in diesel fuel assuming that 98 percent of sulfur in the fuel is oxidized to SO_2 based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
Summary of Tanks MSS Emissions - Tank Cleanings

Description	EPN	Pollutant	Hourly Emissions [1],[2] (lb/hr)	Annual Emissions [1],[2] (tpy)
Vapor Combustion Unit (VCU) for Controlled Standing Idle, Degassing, Forced Ventilation, and Refilling Activities	VCU-TKS	VOC	11.23	0.68
		NO_X	2.10	0.13
		CO	4.19	0.25
		$PM/PM_{10}/PM_{2.5}$	0.16	0.01
		SO_2	0.04	0.00
		H_2S	1.89E-04	1.36E-05
		Benzene	0.08	0.00
Sludge Removal and Vacuum Truck Venting Activities	TKS-MSS	VOC	4.05	0.17
		H_2S	0.00	3.42E-06
		Benzene	0.03	0.00

[1] It is assumed that only one of the tank cleaning operations will occur within one hour on a tank by tank basis, and each tank will be cleaned once every year.

[2] Since the storage tanks can store either crude oil or condensate, hourly and annual emissions from tank cleanings are based on worst-case emissions between crude oil and condensate.

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
Internal Floating Roof Tanks MSS Emissions - Crude Oil

Calculation Methodology:
Tank cleaning involves the following steps:

1. Standing Idle to Control;
2. Degassing to control (assumes saturated vapor space is degassed to a desired concentration based on %LEL);
3. Forced Ventilation to control (using blower) to below a desired %LEL (emissions due to forced ventilation of tank vapor space);
3. Sludge removal using vacuum trucks (emissions due to vapor removed from the tank and vented at the vacuum truck, assumes control);
4. Vacuum truck usage in support of tank cleaning;
5. Refloating of tank to control.

Tank Cleaning Parameters

Parameter	Value	Unit
No. of tank cleanings in a year [1]	4	events/yr
Tank Diameter (D)	262.5	ft
Tank Capacity	21,000,000	gal
Tank Capacity	2,807,292	ft^3
Maximum True Vapor Pressure in tank (TVP 11) [2]	11.00	psia
Vapor MW of Crude Oil TVP 11 (M_V)	50.00	lb/lbmole
Maximum Temperature (T)	554.67	°R
Ideal Gas Constant (R)	10.73	psia-ft^3/lbmol-°R
Vapor Combustion Unit Control Efficiency [1]	99.00%	
Max. Benzene % in Vapor (TVP 11) [3]	0.95%	
Standing Idle Parameters		
Duration Time for Standing Idle [1]	24	hrs/event
Tank Diameter	262.5	ft
Clingage Factor (C_S) [4]	0.006	
Liquid Density (W_l)	7.10	lb/gal
Degassing Parameters		
Duration Time for Degassing [1]	24	hrs/event
Roof Leg Height [5]	7	ft
Vapor Space Volume (V_V) [6]	378,832	ft^3
VOC Saturation Factor [7]	60%	
Forced Ventilation Parameters		
Duration Time for Venting [1]	24	hrs/event
Target Degassing Concentration [1]	10,000	ppmv
Venting Target Concentration [1]	5	%LEL
Lower Explosive Limit (LEL) [1]	1.3	%
Venting Blower Flow Rate [1]	9,500	scfm
Pseudo Surface Velocity (U_s) [8]	0.18	ft/min
Liquid Heel Surface Area (A_P) [9]	54,119	ft^2
Sludge Removal Parameters		
Control Efficiency for Venting Operations	90%	
Duration Time for Venting [1]	3	days/event
Sludge Removal Air Mover Volumetric Flow Rate [1]	100	scfm
Venting Target Concentration [1]	5	%LEL
Lower Explosive Limit (LEL) [1]	1.3	%
Air Mover Venting Concentration [10]	650	ppmv

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
Internal Floating Roof Tanks MSS Emissions - Crude Oil

Vacuum Truck Venting Parameters		
Duration Time for Vacuum Truck Venting [1]	1	hrs/event
Control Efficiency for Venting Operations	90%	
VOC Saturation Factor [11]	0.6	
Vacuum Truck Usage (No. of 100 bbl Trucks) [1]	20	# 100 bbl Trucks
Refilling Parameters		
Maximum Refilling Rate [12]	210,000	gal/hr
Roof Leg Height [5]	7	ft
Vapor Space Volume (V_V) [6]	378,832	ft^3
Duration Time for Refloating Roof [13]	13	hrs/event
Filling Saturation Factor (S) [14]	0.15	

[1] Assumptions made for tanks MSS activities.
[2] Maximum vapor pressure and average vapor pressure were based on Crude Oil TVP 11.
[3] Benzene Vapor Weight Fraction is based on Tanks 4.09D run.
[4] Clingage Factor is obtained from AP-42 Chapter 7.1, Table 7.1-10 for crude oil with light rust shell condition.
[5] Roof leg height of 7 ft was assumed to calculate landing, degassing and refilling losses.
[6] Vapor space volume (ft^3) = Roof Leg Height (ft) x π x (Diameter of Tank (ft))^2/4
[7] Saturation Factor obtained from page 16 of TCEQ MSS guidance - https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/mss/mss-guidance.pdf
[8] Pseudo Surface Velocity U_s (ft/min) = Venting Blower Flowrate (scfm)/ (π x (Diameter of Tank (ft)/2)^2)
[9] Liquid Heel Surface Area A_P (ft^2) = π x (Diameter of Tank (ft)/2)^2
[10] Air Mover Venting Concentration (ppmv) = Venting Target Concentration/100 x Lower Explosive Limit/100 x 1,000,000
[11] Saturation factor obtained from AP-42 Chapter 5.2, Table 5.2-1 for submerged loading: dedicated normal service.
[12] Maximum Refilling rate is conservatively assumed to be 5,000 bbl/hr.
[13] Time to refloat the roof is determined by dividing the volume of the vapor space (gallons) by the filling rate (gal/hr), with 1 hour being the minimum.
Duration time for refloating the roof (hrs) = Vapor space volume (ft^3) x 7.48 (gal/ft^3) / Maximum refilling rate (gal/hr)
[14] Filling Saturation Factor for drain-dry tanks (obtained from AP-42, Chapter 7.1, Table 7.1-19) is used because the emissions for refilling a cleaned tank are the same as the emissions for refilling a drain-dry tank, the only vapors that are accounted for are the vapors from the incoming liquid.

VOC Emissions Estimates from Tank MSS Activities

Tank ID	Description	Standing Idle Losses [1]		Degassing Losses [2]		Forced Ventilation Losses [3]		Sludge Removal Losses [4]		Vacuum Truck Venting Losses [5]		Refilling Losses [6]	
		Duration (hrs)	TVP 11 (lbs/event)	Duration (hrs)	TVP 11 (lbs/event)	Duration (hrs)	TVP 11 (lb/hr)	Duration (days)	TVP 11 (lb/hr)	Duration (hrs)	TVP 11 (lbs/event)	Duration (hrs)	TVP 11 (lbs/event)
TK-501	IFR Tank 501	24	96.83	24	20,724	24	7.27	3	0.48	1	623	13	5,251
TK-502	IFR Tank 502	24	96.83	24	20,724	24	7.27	3	0.48	1	623	13	5,251
TK-503	IFR Tank 503	24	96.83	24	20,724	24	7.27	3	0.48	1	623	13	5,251
TK-504	IFR Tank 504	24	96.83	24	20,724	24	7.27	3	0.48	1	623	13	5,251
TK-505	IFR Tank 505	24	96.83	24	20,724	24	7.27	3	0.48	1	623	13	5,251
TK-506	IFR Tank 506	24	96.83	24	20,724	24	7.27	3	0.48	1	623	13	5,251
TK-507	IFR Tank 507	24	96.83	24	20,724	24	7.27	3	0.48	1	623	13	5,251
TK-508	IFR Tank 508	24	96.83	24	20,724	24	7.27	3	0.48	1	623	13	5,251
TK-509	IFR Tank 509	24	96.83	24	20,724	24	7.27	3	0.48	1	623	13	5,251
TK-510	IFR Tank 510	24	96.83	24	20,724	24	7.27	3	0.48	1	623	13	5,251
TK-511	IFR Tank 511	24	96.83	24	20,724	24	7.27	3	0.48	1	623	13	5,251
TK-512	IFR Tank 512	24	96.83	24	20,724	24	7.27	3	0.48	1	623	13	5,251
TK-SLOP [7]	Slop Oil Tank	24	96.83	24	20,724	24	7.27	3	0.48	1	623	13	5,251

[1] Standing Idle Losses for drain-dry tanks are calculated using equation 2-20 from AP-42 Chapter 7.1, Table 7.1-19.

Standing Idle Losses (lbs/event) = 0.042 x Clingage Factor (bbl/10^3 ft^2) x Liquid Density (W_l) (lb/gal) x (π*(Tank Diameter (D) (ft))^2/4)

$$\text{Standing Idle Losses (lbs/event)} = \frac{0.042}{} \quad \frac{0.006 \text{ bbl}}{10^3 \text{ ft}^2} \quad \frac{7.10 \text{ lb}}{\text{gal}} \quad \frac{3.14}{} \quad \frac{(262.5 \text{ ft})^2}{4} = 96.83 \text{ lbs/event}$$

[2] Degassing losses are calculated using the Ideal Gas Law, vapor pressure at 95°F, and vapor molecular weight of compound in the tank. Assumes saturated vapor space is degassed to a desired concentration based on %LEL.

Degassing Losses (lbs/event) = Material in Saturated Vapor Space Before Degassing - Material Remaining in Vapor Space After Degassing = (P*Vv/R*T) x Mv x Saturation Factor$_{\text{Before Degassing}}$ - (P*Vv/R*T) x Mv x Saturation Factor x Degassing Concentration)$_{\text{After Degassing}}$

$$\text{Degassing Losses (lbs/event)} = \frac{11.00 \text{ psia}}{} \quad \frac{378{,}832 \text{ ft}^3}{} \quad \frac{\text{lbmol-}^\circ\text{R}}{10.73 \text{ psia-ft}^3} \quad \frac{}{554.67 \text{ R}} \quad \frac{50 \text{ lb}}{\text{lbmol}} \quad \frac{60\%}{} \quad - \quad \frac{14.7 \text{ psia}}{} \quad \frac{378{,}832 \text{ ft}^3}{} \quad \frac{\text{lbmol-}^\circ\text{R}}{10.73 \text{ psia-ft}^3} \quad \frac{}{554.67 \text{ R}} \quad \frac{50 \text{ lb}}{\text{lbmol}} \quad \frac{60\%}{} \quad \frac{10{,}000 \text{ ppmv}}{1{,}000{,}000} = 20{,}724 \text{ lbs/event}$$

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[3] Forced Ventilation losses are calculated using the correlation from page 17 of the TCEQ MSS guidance document - http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/mss/mss-guidance.pdf.

Forced Ventilation Losses (lb/hr) = 4.14 x 10^{-5} x (Pseudo Surface Velocity U_s)$^{0.78}$ x Vapor Pressure P_v x (Vapor Molecular Weight M_v)$^{0.67}$ x (Liquid Heel Surface Area A_P)$^{0.94}$

Forced Ventilation Losses (lb/hr) =	4.14 x 10-5	0.001^0.78 m	10,000 ppmv	14.7 psia	101325 Pa	50^0.67 lb	5,028 m^2 = 7.27 lb/hr
		sec	1,000,000		14.7 psia	lbmol	

[4] Sludge Removal losses are calculated using the venting volumetric flow rate and venting concentration.

Sludge Removal Losses (lb/hr) = Vapor Pressure (psia) x Air Mover Volumetric Flow Rate (scfm) x 60 (min/hr) x Vapor Molecular Weight (lb/lbmol) x Air Mover Venting Concentration (ppmv)/1,000,000/(Ideal Gas Constant (psia-ft^3/lbmol-^{o}R) x Temperature (^{o}R))

Sludge Removal Losses (lb/hr) =	14.7 psia	100 scfm	60 min	50 lb	650 ppmv	lbmol-^{o}R	= 0.48 lb/hr
			hr	lbmol	1,000,000	10.73 psia-ft^3	554.67 R

[5] Vacuum Truck Venting losses are calculated using the loading loss equation from AP-42, Section 5.2.

Vacuum Truck Venting Losses (lbs/event) = 12.46 x Saturation Factor x Vapor Pressure (psia) x Vapor Molecular Weight (lb/lbmol)/(Temperature (^{o}R)) x Vacuum Truck Usage (No. of 100 bbl trucks) x 100 (bbl/truck) x 42 (gal/bbl) / 1000

Vacuum Truck Venting Losses (lbs/event) =	12.46	0.6	11.00 psia	50 lb		20 trucks	100 bbl	42 gal	1	= 623 lbs/event
				lbmol	554.67 R		truck	bbl	1,000	

[6] Refilling Losses for drain-dry tanks are calculated using equation 2-26 from AP-42 Chapter 7.1, Table 7.1-19.

Refilling Losses (lbs/event) = Filling Saturation Factor x Vapor Space Volume (ft^3) x Vapor Pressure (psia) x Vapor Molecular Weight (lb/lbmol)/(Ideal Gas Constant (psia-ft^3/lbmol-^{o}R) x Temperature (^{o}R))

Refilling Losses (lbs/event) =	0.15	378,832 ft^3	11.00 psia	50 lb	lbmol-^{o}R		= 5,251 lbs/event
				lbmol	10.73 psia-ft^3	554.67 R	

[7] The volume of Slop Tank is assumed to be the same as Product tanks to be conservative.

Hourly and Annual VOC Emissions from Tank MSS Activities - Sludge Removal and Vacuum Truck Venting

Tank ID	Description	EPN	Controlled Sludge Removal Emissions [1]		Controlled Vacuum Truck Venting Emissions [2]		VOC Emissions [3]		Benzene Emissions [5]		H_2S Emissions [6]	
			Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)
TK-501	IFR Tank 501	TKS-MSS	0.05	6.94E-03	3.11	0.12	3.11	0.13	0.03	1.25E-03	6.81E-05	2.88E-06
TK-502	IFR Tank 502	TKS-MSS	0.05	6.94E-03	3.11	0.12	3.11	0.13	0.03	1.25E-03	6.81E-05	2.88E-06
TK-503	IFR Tank 503	TKS-MSS	0.05	6.94E-03	3.11	0.12	3.11	0.13	0.03	1.25E-03	6.81E-05	2.88E-06
TK-504	IFR Tank 504	TKS-MSS	0.05	6.94E-03	3.11	0.12	3.11	0.13	0.03	1.25E-03	6.81E-05	2.88E-06
TK-505	IFR Tank 505	TKS-MSS	0.05	6.94E-03	3.11	0.12	3.11	0.13	0.03	1.25E-03	6.81E-05	2.88E-06
TK-506	IFR Tank 506	TKS-MSS	0.05	6.94E-03	3.11	0.12	3.11	0.13	0.03	1.25E-03	6.81E-05	2.88E-06
TK-507	IFR Tank 507	TKS-MSS	0.05	6.94E-03	3.11	0.12	3.11	0.13	0.03	1.25E-03	6.81E-05	2.88E-06
TK-508	IFR Tank 508	TKS-MSS	0.05	6.94E-03	3.11	0.12	3.11	0.13	0.03	1.25E-03	6.81E-05	2.88E-06
TK-509	IFR Tank 509	TKS-MSS	0.05	6.94E-03	3.11	0.12	3.11	0.13	0.03	1.25E-03	6.81E-05	2.88E-06
TK-510	IFR Tank 510	TKS-MSS	0.05	6.94E-03	3.11	0.12	3.11	0.13	0.03	1.25E-03	6.81E-05	2.88E-06
TK-511	IFR Tank 511	TKS-MSS	0.05	6.94E-03	3.11	0.12	3.11	0.13	0.03	1.25E-03	6.81E-05	2.88E-06
TK-512	IFR Tank 512	TKS-MSS	0.05	6.94E-03	3.11	0.12	3.11	0.13	0.03	1.25E-03	6.81E-05	2.88E-06
TK-SLOP [7]	Slop Oil Tank	TKS-MSS	0.05	6.94E-03	3.11	0.12	3.11	0.13	0.03	1.25E-03	6.81E-05	2.88E-06
						Total [4]	**3.11**	**0.13**	**0.03**	**1.25E-03**	**6.81E-05**	**2.88E-06**

[1] Controlled Sludge Removal Hourly Emissions (lb/hr) = Uncontrolled Sludge Removal Losses (lb/hr) x (1 - Control Eff. (%))

Controlled Sludge Removal Hourly Emissions (lb/hr) =	0.48 lbs	(1 - 0.9)	= 0.05 lb/hr
	event		

Controlled Sludge Removal Annual Emissions (tpy) = Uncontrolled Sludge Removal Losses (lb/hr) x Sludge Removal Duration (days/event) x 24 (hrs/day) x No. of events per year (events/yr) x (1 - Control Eff. (%)) x (1 ton/2,000 lbs)

Controlled Sludge Removal Annual Emissions (tpy) =	0.48 lbs	3 days	24 hrs	4 event	(1 - 0.9)	1 ton	= 0.01 tpy
	hr	event	day	yr		2,000 lbs	

[2] Controlled Vacuum Truck Venting Hourly Emissions (lb/hr) = Uncontrolled Vacuum Truck Venting Losses (lbs/event) / Vacuum Truck Usage x (1 - Control Eff. (%))

Controlled Vacuum Truck Venting Hourly Emissions (lb/hr) =	623 lbs	1 event	(1 - 0.9)	= 3.11 lb/hr
	event	20 trucks-hr		

Controlled Vacuum Truck Venting Annual Emissions (tpy) = Uncontrolled Vacuum Truck Venting Losses (lbs/event) x No. of events per year (events/yr) x (1 - Control Eff. (%)) x (1 ton/2,000 lbs)

Controlled Vacuum Truck Venting Annual Emissions (tpy) =	623 lbs	4 event	(1 - 0.9)	1 ton	= 0.12 tpy
	event	year		2,000 lbs	

[3] Hourly VOC Emissions (lb/hr) = MAX(Controlled Sludge Removal (lb/hr), Controlled Vacuum Truck Venting (lb/hr))
Annual VOC Emissions (tpy) = SUM(Controlled Sludge Removal (tpy), Controlled Vacuum Truck Venting (tpy))

[4] It is assumed that only one of the tank cleaning operations will occur within one hour on a tank by tank basis, and each tank will be cleaned up to four (4) times a year.

[5] Benzene Hourly Emissions (lb/hr) = Max Benzene % in Vapor x VOC Hourly Emissions (lb/hr)

Benzene Hourly Emissions (lb/hr) =	1.0%	3.11 lbs	= 0.03 lb/hr
		hr	

Benzene Annual Emissions (tpy) = Max Benzene % in Vapor x VOC Annual Emissions (tpy)

Benzene Annual Emissions (tpy) =	1.0%	0.13 tons	= 1.25E-3 tpy
		yr	

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[6] H_2S Hourly Emissions (lb/hr) = Max H_2S Mass Ratio (lb H_2S/lb VOC) x VOC Hourly Emissions (lb/hr)

$$H_2S \text{ Hourly Emissions (lb/hr)} = \frac{2.19E\text{-}05 \text{ lb H2S}}{\text{lb VOC}} \cdot \frac{3.11 \text{ lbs}}{\text{hr}} = 6.81E\text{-}05 \text{ lb/hr}$$

H_2S Annual Emissions (tpy) = Max H_2S Mass Ratio (lb H_2S/lb VOC) x VOC Annual Emissions (tpy)

$$H_2S \text{ Annual Emissions (tpy)} = \frac{2.19E\text{-}05 \text{ lb H2S}}{\text{lb VOC}} \cdot \frac{0.13 \text{ tons}}{\text{yr}} = 2.88E\text{-}6 \text{ tpy}$$

Hourly and Annual VOC Emissions from Tank MSS Activities - Standing Idle, Degassing, Forced Ventilation, and Refilling

Tank ID	Description	EPN	Controlled Standing Idle Emissions [1]		Controlled Degassing Emissions [2]		Controlled Forced Ventilation Emissions [3]		Controlled Refilling Emissions [4]		VOC Emissions [5]		Benzene Emissions [6]	
			Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)
TK-501	IFR Tank 501	VCU-TKS	0.04	1.94E-03	8.64	0.41	0.07	3.49E-03	3.89	0.11	8.64	0.52	0.08	4.99E-03
TK-502	IFR Tank 502	VCU-TKS	0.04	1.94E-03	8.64	0.41	0.07	3.49E-03	3.89	0.11	8.64	0.52	0.08	4.99E-03
TK-503	IFR Tank 503	VCU-TKS	0.04	1.94E-03	8.64	0.41	0.07	3.49E-03	3.89	0.11	8.64	0.52	0.08	4.99E-03
TK-504	IFR Tank 504	VCU-TKS	0.04	1.94E-03	8.64	0.41	0.07	3.49E-03	3.89	0.11	8.64	0.52	0.08	4.99E-03
TK-505	IFR Tank 505	VCU-TKS	0.04	1.94E-03	8.64	0.41	0.07	3.49E-03	3.89	0.11	8.64	0.52	0.08	4.99E-03
TK-506	IFR Tank 506	VCU-TKS	0.04	1.94E-03	8.64	0.41	0.07	3.49E-03	3.89	0.11	8.64	0.52	0.08	4.99E-03
TK-507	IFR Tank 507	VCU-TKS	0.04	1.94E-03	8.64	0.41	0.07	3.49E-03	3.89	0.11	8.64	0.52	0.08	4.99E-03
TK-508	IFR Tank 508	VCU-TKS	0.04	1.94E-03	8.64	0.41	0.07	3.49E-03	3.89	0.11	8.64	0.52	0.08	4.99E-03
TK-509	IFR Tank 509	VCU-TKS	0.04	1.94E-03	8.64	0.41	0.07	3.49E-03	3.89	0.11	8.64	0.52	0.08	4.99E-03
TK-510	IFR Tank 510	VCU-TKS	0.04	1.94E-03	8.64	0.41	0.07	3.49E-03	3.89	0.11	8.64	0.52	0.08	4.99E-03
TK-511	IFR Tank 511	VCU-TKS	0.04	1.94E-03	8.64	0.41	0.07	3.49E-03	3.89	0.11	8.64	0.52	0.08	4.99E-03
TK-512	IFR Tank 512	VCU-TKS	0.04	1.94E-03	8.64	0.41	0.07	3.49E-03	3.89	0.11	8.64	0.52	0.08	4.99E-03
TK-SLOP [7]	Slop Oil Tank	VCU-TKS	0.04	1.94E-03	8.64	0.41	0.07	3.49E-03	3.89	0.11	8.64	0.52	0.08	4.99E-03
										Total [7]	**8.64**	**0.52**	**0.08**	**4.99E-03**

[1] Controlled Standing Idle Hourly Emissions (lb/hr) = Uncontrolled Standing Idle Losses (lbs/event) / Standing Idle Duration (hrs/event) x (1 - VCU Control Eff. (%))

$$\text{Controlled Standing Idle Hourly Emissions (lb/hr)} = \frac{96.83 \text{ lbs}}{\text{event}} \cdot \frac{1 \text{ event}}{24 \text{ hrs}} \cdot (1 - 0.99) = 0.04 \text{ lb/hr}$$

Controlled Standing Idle Annual Emissions (tpy) = Uncontrolled Standing Idle Losses (lbs/event) x No. of events per year (events/yr) x (1 - VCU Control Eff. (%)) x (1 ton/2,000 lbs)

$$\text{Controlled Standing Idle Annual Emissions (tpy)} = \frac{96.83 \text{ lbs}}{\text{event}} \cdot \frac{4 \text{ events}}{\text{yr}} \cdot (1 - 0.99) \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lbs}} = 1.94E\text{-}03 \text{ tpy}$$

[2] Controlled Degassing Hourly Emissions (lb/hr) = Uncontrolled Degassing Losses (lbs/event) / Degassing Duration (hrs/event) x (1 - VCU Control Eff. (%))

$$\text{Controlled Degassing Hourly Emissions (lb/hr)} = \frac{20{,}724 \text{ lbs}}{\text{event}} \cdot \frac{1 \text{ event}}{24 \text{ hrs}} \cdot (1 - 0.99) = 8.64 \text{ lb/hr}$$

Controlled Degassing Annual Emissions (tpy) = Uncontrolled Degassing Losses (lbs/event) x No. of events per year (events/yr) x (1 - VCU Control Eff. (%)) x (1 ton/2,000 lbs)

$$\text{Controlled Degassing Annual Emissions (tpy)} = \frac{20{,}724 \text{ lbs}}{\text{event}} \cdot \frac{4 \text{ events}}{\text{yr}} \cdot (1 - 0.99) \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lbs}} = 0.41 \text{ tpy}$$

[3] Controlled Forced Ventilation Hourly Emissions (lb/hr) = Uncontrolled Forced Ventilation Losses (lbs/hr) x (1 - VCU Control Eff. (%))

$$\text{Controlled Forced Ventilation Hourly Emissions (lb/hr)} = \frac{7.27 \text{ lb}}{\text{hr}} \cdot (1 - 0.99) = 0.07 \text{ lb/hr}$$

Controlled Forced Ventilation Annual Emissions (tpy) = Controlled Forced Ventilation Losses (lb/hr) x Forced Ventilation Duration (hrs/event) x No. of events per year (events/yr) x (1 ton/2,000 lbs)

$$\text{Controlled Forced Ventilation Annual Emissions (tpy)} = \frac{0.07 \text{ lb}}{\text{hr}} \cdot \frac{24 \text{ hrs}}{\text{event}} \cdot \frac{4 \text{ events}}{\text{yr}} \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lbs}} = 3.49E\text{-}03 \text{ tpy}$$

[4] Controlled Refilling Hourly Emissions (lb/hr) = Uncontrolled Refilling Losses (lbs/event) / Refilling Duration (hrs/event) x (1 - VCU Control Eff. (%))

$$\text{Controlled Refilling Hourly Emissions (lb/hr)} = \frac{5{,}251 \text{ lbs}}{\text{event}} \cdot \frac{1 \text{ event}}{13 \text{ hrs}} \cdot (1 - 0.99) = 3.89 \text{ lb/hr}$$

Controlled Refilling Annual Emissions (tpy) = Uncontrolled Refilling Losses (lbs/event) x No. of events per year (events/yr) x (1 - VCU Control Eff. (%)) x (1 ton/2,000 lbs)

$$\text{Controlled Refilling Annual Emissions (tpy)} = \frac{5{,}251 \text{ lbs}}{\text{event}} \cdot \frac{4 \text{ events}}{\text{yr}} \cdot (1 - 0.99) \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lbs}} = 0.11 \text{ tpy}$$

[5] Controlled VOC Hourly Emissions (lb/hr) = MAX(Controlled Hourly Standing Idle (lb/hr), Degassing (lb/hr), Forced Ventilation (lb/hr), Refilling Losses (lb/hr))
Controlled VOC Annual Emissions (tpy) = SUM(Controlled Annual Standing Idle (tpy), Degassing (tpy), Forced Ventilation (tpy), Refilling Losses (tpy))

[6] Benzene Hourly Emissions (lb/hr) = Max Benzene % in Vapor x VOC Hourly Emissions (lb/hr)

$$\text{Benzene Hourly Emissions (lb/hr)} = 0.95\% \cdot \frac{8.64 \text{ lbs}}{\text{hr}} = 0.08 \text{ lb/hr}$$

Benzene Annual Emissions (tpy) = Max Benzene % in Vapor x VOC Annual Emissions (tpy)

$$\text{Benzene Annual Emissions (tpy)} = 0.95\% \cdot \frac{0.52 \text{ tons}}{\text{yr}} = 4.99E\text{-}3 \text{ tpy}$$

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[7] It is assumed that only one of the tank cleaning operations will occur within one hour on a tank by tank basis, and a maximum of four tanks will be cleaned every year.

Hourly and Annual NO_X, CO, PM, H_2S, and SO_2 Emissions Estimates from Tank MSS Activities

Parameter	Value	Unit
NO_X Emission Factor [1]	0.100	lb/MMBtu
CO Emission Factor [1]	0.2000	lb/MMBtu
$PM/PM_{10}/PM_{2.5}$ Emission Factor [2]	17.74	lb/MMscf
H_2S Max Vapor Fraction in Crude oil [3]	2.40E-05	
Maximum Mass Ratio of H_2S in Crude Oil [4]	2.19E-05	lb H_2S/lb VOC
H_2S VCU DRE	99.00%	
H_2S Molecular Weight	34.1	lb/lbmole
SO_2 Molecular Weight	64.07	lb/lbmole
Product Heat of Combustion [5]	18,352	Btu/lb
Molar Volume	385.44	scf/lbmole

[1] NOx and CO emission factors are representative design emission factors.

[2] PM Emission Factor for Crude Oil = PM Emission Factor for Natural Gas Combustion (lb/MMscf) x (1/Natural Gas Heat of Combustion (Btu/scf)) x Crude Oil Heat of Combustion (Btu/lb) x Crude Oil Vapor MW (lb/lbmole) x (1/Molar Volume (scf/lbmole@68.33°F))

$$\text{PM Emission Factor} = \frac{7.6\text{ lb}}{\text{MMscf}} \cdot \frac{\text{scf}}{1{,}020\text{ Btu}} \cdot \frac{18{,}352\text{ Btu}}{\text{lb}} \cdot \frac{50\text{ lb}}{\text{lbmole}} \cdot \frac{\text{lbmole}}{385.44\text{ scf}} = 17.74\text{ lb/MMscf}$$

[3] Maximum H_2S vapor fraction is assumed to be 24 ppmv for sweet crude.

[4] H_2S Mass Ratio in Crude Oil (lb H_2S/lb VOC) = H_2S Vapor Fraction in Crude Oil x H_2S MW (lb/lbmole)/Crude Oil Vapor MW (lb/lbmole) x 14.7 psia/Vapor Pressure of Crude Oil (psia)

$$\text{Max } H_2S \text{ Mass Ratio in Crude Oil (lb } H_2S\text{/lb VOC)} = \frac{0.000024}{} \cdot \frac{34.1\text{ lb}}{\text{lbmole}} \cdot \frac{\text{lbmole}}{50\text{ lb}} \cdot \frac{14.7\text{ psia}}{11\text{ psia}} = 2.19\text{E-05 lb H2S/lb VOC}$$

[5] Product Heat of Combustion obtained from Table A1, Biomass Energy Data Book, Edition 4, 2011, Oak Ridge National Laboratory (Oak Ridge, TN).

Tank ID	Description	EPN	Uncontrolled VOC Hourly Emissions [1] (lb/hr)	Uncontrolled VOC Annual Emissions [2] (tpy)	NO_X Hourly Emissions [3] (lb/hr)	NO_X Annual Emissions [4] (tpy)	CO Hourly Emissions [3] (lb/hr)	CO Annual Emissions [4] (tpy)	$PM/PM_{10}/PM_{2.5}$ Hourly Emissions [5][6] (lb/hr)	$PM/PM_{10}/PM_{2.5}$ Annual Emissions [5][7] (tpy)	H_2S Hourly Emissions [8] (lb/hr)	H_2S Annual Emissions [9] (tpy)	SO_2 Hourly Emissions [10] (lb/hr)	SO_2 Annual Emissions [10] (tpy)
TK-501	IFR Tank 501	VCU-TKS	863.52	52.49	1.58	0.10	3.17	0.19	0.12	7.18E-03	1.89E-04	1.15E-05	0.04	2.16E-03
TK-502	IFR Tank 502	VCU-TKS	863.52	52.49	1.58	0.10	3.17	0.19	0.12	7.18E-03	1.89E-04	1.15E-05	0.04	2.16E-03
TK-503	IFR Tank 503	VCU-TKS	863.52	52.49	1.58	0.10	3.17	0.19	0.12	7.18E-03	1.89E-04	1.15E-05	0.04	2.16E-03
TK-504	IFR Tank 504	VCU-TKS	863.52	52.49	1.58	0.10	3.17	0.19	0.12	7.18E-03	1.89E-04	1.15E-05	0.04	2.16E-03
TK-505	IFR Tank 505	VCU-TKS	863.52	52.49	1.58	0.10	3.17	0.19	0.12	7.18E-03	1.89E-04	1.15E-05	0.04	2.16E-03
TK-506	IFR Tank 506	VCU-TKS	863.52	52.49	1.58	0.10	3.17	0.19	0.12	7.18E-03	1.89E-04	1.15E-05	0.04	2.16E-03
TK-507	IFR Tank 507	VCU-TKS	863.52	52.49	1.58	0.10	3.17	0.19	0.12	7.18E-03	1.89E-04	1.15E-05	0.04	2.16E-03
TK-508	IFR Tank 508	VCU-TKS	863.52	52.49	1.58	0.10	3.17	0.19	0.12	7.18E-03	1.89E-04	1.15E-05	0.04	2.16E-03
TK-509	IFR Tank 509	VCU-TKS	863.52	52.49	1.58	0.10	3.17	0.19	0.12	7.18E-03	1.89E-04	1.15E-05	0.04	2.16E-03
TK-510	IFR Tank 510	VCU-TKS	863.52	52.49	1.58	0.10	3.17	0.19	0.12	7.18E-03	1.89E-04	1.15E-05	0.04	2.16E-03
TK-511	IFR Tank 511	VCU-TKS	863.52	52.49	1.58	0.10	3.17	0.19	0.12	7.18E-03	1.89E-04	1.15E-05	0.04	2.16E-03
TK-512	IFR Tank 512	VCU-TKS	863.52	52.49	1.58	0.10	3.17	0.19	0.12	7.18E-03	1.89E-04	1.15E-05	0.04	2.16E-03
TK-SLOP [7]	Slop Oil Tank	VCU-TKS	863.52	52.49	1.58	0.10	3.17	0.19	0.12	7.18E-03	1.89E-04	1.15E-05	0.04	2.16E-03
				Total [11]	**1.58**	**0.10**	**3.17**	**0.19**	**0.12**	**7.18E-03**	**1.89E-04**	**1.15E-05**	**0.04**	**2.16E-03**

[1] Uncontrolled Hourly VOC Emissions (lb/hr) = MAX(Uncontrolled Hourly Standing Idle (lb/hr), Degassing (lb/hr), Forced Ventilation (lb/hr), Refilling Emissions (lb/hr))

[2] Uncontrolled Annual VOC Emissions (tpy) = SUM(Uncontrolled Annual Standing Idle (tpy), Degassing (tpy), Forced Ventilation (tpy), Refilling Emissions (tpy))

[3] NO_X and CO Hourly Emissions (lb/hr) = Uncontrolled VOC Emissions (lb/hr) x NO_X or CO Emission Factor (lb/MMBtu) x Product Heat of Combustion (Btu/lb) x (1 MMBtu/1,000,000 Btu)

$$NO_X \text{ Hourly Emissions (lb/hr)} = \frac{864\text{ lb}}{\text{hr}} \cdot \frac{0.1\text{ lb}}{\text{MMBtu}} \cdot \frac{18{,}352\text{ Btu}}{\text{lb}} \cdot \frac{1\text{ MMBtu}}{1{,}000{,}000\text{ Btu}} = 1.58\text{ lb/hr}$$

[4] NO_X and CO Annual Emissions (tpy) = Uncontrolled VOC Emissions (tpy) x NO_X or CO Emission Factor (lb/MMBtu) x Product Heat of Combustion (Btu/lb) x (1 MMBtu/1,000,000 Btu)

$$NO_X \text{ Annual Emissions (tpy)} = \frac{52.49\text{ tons}}{\text{yr}} \cdot \frac{0.1\text{ lb}}{\text{MMBtu}} \cdot \frac{18{,}352\text{ Btu}}{\text{lb}} \cdot \frac{1\text{ MMBtu}}{1{,}000{,}000\text{ Btu}} = 0.10\text{ tpy}$$

[5] Hourly and Annual emissions of Total PM = PM_{10} = $PM_{2.5}$.

[6] PM Hourly Emissions (lb/hr) = Uncontrolled VOC Emissions (lb/hr) x (1/Vapor MW (lb/lbmole)) x Molar Volume (scf/lbmole) x Emission Factor (lb/MMscf) x (1 MMscf/1,000,000 scf)

$$\text{PM Hourly Emissions (lb/hr)} = \frac{864\text{ lb}}{\text{hr}} \cdot \frac{\text{lbmole}}{50\text{ lb}} \cdot \frac{385.44\text{ scf}}{\text{lbmole}} \cdot \frac{17.74\text{ lb}}{\text{MMscf}} \cdot \frac{1\text{ MMscf}}{1{,}000{,}000\text{ scf}} = 0.12\text{ lb/hr}$$

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[7] PM Annual Emissions (tpy) = Uncontrolled VOC Emissions (tpy) x (1/Vapor MW (lb/lbmole)) x Molar Volume (scf/lbmole) x Emission Factor (lb/MMscf) x (1 MMscf/1,000,000 scf)

$$\text{PM Annual Emissions (tpy)} = \frac{52.49\ \text{tons}}{\text{yr}} \cdot \frac{\text{lbmole}}{50\ \text{lb}} \cdot \frac{385.44\ \text{scf}}{\text{lbmole}} \cdot \frac{17.74\ \text{lb}}{\text{MMscf}} \cdot \frac{1\ \text{MMscf}}{1{,}000{,}000\ \text{scf}} = 7.18\text{E-}03\ \text{tpy}$$

[8] H_2S Hourly Emissions (lb/hr) = Max H_2S Mass Ratio (lb H_2S/lb VOC) x Uncontrolled VOC Emissions (lb/hr) x (1 - H_2S VCU DRE (%))

$$H_2S\ \text{Hourly Emissions (lb/hr)} = \frac{2.19\text{E-}05\ \text{lb H2S}}{\text{lb VOC}} \cdot \frac{864\ \text{lb}}{\text{hr}} \cdot (1 - 0.99) = 1.89\text{E-}04\ \text{lb/hr}$$

[9] H_2S Annual Emissions (tpy) = Max H_2S Mass Ratio (lb H_2S/lb VOC) x Uncontrolled VOC Emissions (tpy) x (1 - VCU Flare DRE (%))

$$H_2S\ \text{Annual Emissions (tpy)} = \frac{2.19\text{E-}05\ \text{lb H2S}}{\text{lb VOC}} \cdot \frac{52.49\ \text{tons}}{\text{yr}} \cdot (1 - 0.99) = 1.15\text{E-}5\ \text{tpy}$$

[10] SO_2 emissions assume 100% of Uncontrolled H_2S emissions

[11] It is assumed that only one of the tank cleaning operations will occur within one hour on a tank by tank basis, and a maximum of four tanks will be cleaned every year.

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Calculation Methodology:
Tank cleaning involves the following steps:

1. Standing Idle to Control;
2. Degassing to control (assumes saturated vapor space is degassed to a desired concentration based on %LEL);
3. Forced Ventilation to control (using blower) to below a desired %LEL (emissions due to forced ventilation of tank vapor space);
3. Sludge removal using vacuum trucks (emissions due to vapor removed from the tank and vented at the vacuum truck, assumes control);
4. Vacuum truck usage in support of tank cleaning;
5. Refloating of tank to control.

Tank Cleaning Parameters

Parameter	Value	Unit
No. of tank cleanings in a year [1]	4	events/yr
Tank Diameter (D)	262.5	ft
Tank Capacity	21,000,000	gal
Tank Capacity	2,807,292	ft^3
Maximum True Vapor Pressure in tank [2]	11.00	psia
Vapor MW of Condensate TVP 11 (M_V)	65.00	lb/lbmole
Maximum Temperature (T)	554.67	°R
Ideal Gas Constant (R)	10.73	psia-ft^3/lbmol-°R
Vapor Combustion Unit (VCU) Control Efficiency [1]	99.00%	
Max. Benzene % in Vapor (TVP 11) [3]	0.43%	
Standing Idle Parameters		
Duration Time for Standing Idle [1]	24	hrs/event
Tank Diameter	262.5	ft
Clingage Factor (C_S) [4]	0.0015	
Liquid Density (W_l)	5.60	lb/gal
Degassing Parameters		
Duration Time for Degassing [1]	24	hrs/event
Roof Leg Height [5]	7	ft
Vapor Space Volume (V_V) [6]	378,832	ft^3
VOC Saturation Factor [7]	60%	
Forced Ventilation Parameters		
Duration Time for Venting [1]	24	hrs/event
Target Degassing Concentration [1]	10,000	ppmv
Venting Target Concentration [1]	5	%LEL
Lower Explosive Limit (LEL) [1]	1.3	%
Venting Blower Flow Rate [1]	9,500	scfm
Pseudo Surface Velocity (U_s) [8]	0.18	ft/min
Liquid Heel Surface Area (A_P) [9]	54,119	ft^2
Sludge Removal Parameters		
Control Efficiency for Venting Operations	90%	
Duration Time for Venting [1]	3	days/event
Sludge Removal Air Mover Volumetric Flow Rate [1]	100	scfm
Venting Target Concentration [1]	5	%LEL
Lower Explosive Limit (LEL) [1]	1.3	%
Air Mover Venting Concentration [10]	650	ppmv

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Vacuum Truck Venting Parameters		
Duration Time for Vacuum Truck Venting [1]	1	hrs/event
Control Efficiency for Venting Operations	90%	
VOC Saturation Factor [11]	0.6	
Vacuum Truck Usage (No. of 100 bbl Trucks) [1]	20	# 100 bbl Trucks
Refilling Parameters		
Maximum Refilling Rate [12]	210,000	gal/hr
Roof Leg Height [5]	7	ft
Vapor Space Volume (V_V) [6]	378,832	ft^3
Duration Time for Refloating Roof [13]	13	hrs/event
Filling Saturation Factor (S) [14]	0.15	

[1] Assumptions made for tanks MSS activities.
[2] Maximum vapor pressure and average vapor pressure are based on Condensate TVP 11.
[3] Benzene Vapor Weight Fraction is based on Tanks 4.09D run.
[4] Clingage Factor is obtained from AP-42 Chapter 7.1, Table 7.1-10 for gasoline with light rust shell condition.
[5] Roof leg height of 7 ft was assumed to calculate landing, degassing and refilling losses.
[6] Vapor space volume (ft^3) = Roof Leg Height (ft) x π x (Diameter of Tank (ft))^2/4
[7] Saturation Factor obtained from page 16 of TCEQ MSS guidance - https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/mss/mss-guidance.pdf
[8] Pseudo Surface Velocity U_s (ft/min) = Venting Blower Flowrate (scfm)/ (π x (Diameter of Tank (ft)/2)^2)
[9] Liquid Heel Surface Area A_P (ft^2) = π x (Diameter of Tank (ft)/2)^2
[10] Air Mover Venting Concentration (ppmv) = Venting Target Concentration/100 x Lower Explosive Limit/100 x 1,000,000
[11] Saturation factor obtained from AP-42 Chapter 5.2, Table 5.2-1 for submerged loading: dedicated normal service.
[12] Maximum Refilling rate is conservatively assumed to be 5,000 bbl/hr.
[13 Time to refloat the roof is determined by dividing the volume of the vapor space (gallons) by the filling rate (gal/hr), with 1 hour being the minimum.
Duration time for refloating the roof (hrs) = Vapor space volume (ft^3) x 7.48 (gal/ft^3) / Maximum refilling rate (gal/hr)
[14] Filling Saturation Factor for drain-dry tanks (obtained from AP-42, Chapter 7.1, Table 7.1-19) is used because the emissions for refilling a cleaned tank are the same as the emissions for refilling a drain-dry tank, the only vapors that are accounted for are the vapors from the incoming liquid.

VOC Emissions Estimates from Tank MSS Activities

Tank ID	Description	Standing Idle Losses [1]		Degassing Losses [2]		Forced Ventilation Losses [3]		Sludge Removal Losses [4]		Vacuum Truck Venting Losses [5]		Refilling Losses [6]	
		Duration (hrs)	TVP 11 (lbs/event)	Duration (hrs)	TVP 11 (lbs/event)	Duration (hrs)	TVP 11 (lb/hr)	Duration (days)	TVP 11 (lb/hr)	Duration (hrs)	TVP 11 (lbs/event)	Duration (hrs)	TVP 11 (lbs/event)
TK-501	IFR Tank 501	24	19.09	24	26,942	24	8.67	3	0.63	1	810	13	6,827
TK-502	IFR Tank 502	24	19.09	24	26,942	24	8.67	3	0.63	1	810	13	6,827
TK-503	IFR Tank 503	24	19.09	24	26,942	24	8.67	3	0.63	1	810	13	6,827
TK-504	IFR Tank 504	24	19.09	24	26,942	24	8.67	3	0.63	1	810	13	6,827
TK-505	IFR Tank 505	24	19.09	24	26,942	24	8.67	3	0.63	1	810	13	6,827
TK-506	IFR Tank 506	24	19.09	24	26,942	24	8.67	3	0.63	1	810	13	6,827
TK-507	IFR Tank 507	24	19.09	24	26,942	24	8.67	3	0.63	1	810	13	6,827
TK-508	IFR Tank 508	24	19.09	24	26,942	24	8.67	3	0.63	1	810	13	6,827
TK-509	IFR Tank 509	24	19.09	24	26,942	24	8.67	3	0.63	1	810	13	6,827
TK-510	IFR Tank 510	24	19.09	24	26,942	24	8.67	3	0.63	1	810	13	6,827
TK-511	IFR Tank 511	24	19.09	24	26,942	24	8.67	3	0.63	1	810	13	6,827
TK-512	IFR Tank 512	24	19.09	24	26,942	24	8.67	3	0.63	1	810	13	6,827
TK-SLOP [7]	Slop Oil Tank	24	19.09	24	26,942	24	8.67	3	0.63	1	810	13	6,827

[1] Standing Idle Losses for drain-dry tanks are calculated using equation 2-20 from AP-42 Chapter 7.1, Table 7.1-19.

Standing Idle Losses (lbs/event) = 0.042 x Clingage Factor (bbl/10^3 ft^2) x Liquid Density (W_l) (lb/gal) x (π*(Tank Diameter (D) (ft))^2/4)

$$\text{Standing Idle Losses (lbs/event)} = \frac{0.042}{} \times \frac{0.0015 \text{ bbl}}{10^3 \text{ ft}^2} \times \frac{5.60 \text{ lb}}{\text{gal}} \times \frac{3.14}{} \times \frac{(262.5 \text{ ft})^2}{4} = 19.09 \text{ lbs/event}$$

[2] Degassing losses are calculated using the Ideal Gas Law, vapor pressure at 95°F, and vapor molecular weight of compound in the tank. Assumes saturated vapor space is degassed to a desired concentration based on %LEL.

Degassing Losses (lbs/event) = Material in Saturated Vapor Space Before Degassing - Material Remaining in Vapor Space After Degassing = $(P*Vv/R*T) \times Mv \times \text{Saturation Factor})_{\text{Before Degassing}} - (P*Vv/R*T) \times Mv \times \text{Saturation Factor} \times \text{Degassing Concentration})_{\text{After Degassing}}$

$$\text{Degassing Losses (lbs/event)} = \frac{11.00 \text{ psia}}{} \times \frac{378{,}832 \text{ ft}^3}{} \times \frac{\text{lbmol-}^\circ\text{R}}{10.73 \text{ psia-ft}^3} \times \frac{}{554.67 \text{ R}} \times \frac{65 \text{ lb}}{\text{lbmol}} \times \frac{60\%}{} - \frac{14.7 \text{ psia}}{} \times \frac{378{,}832 \text{ ft}^3}{} \times \frac{\text{lbmol-}^\circ\text{R}}{10.73 \text{ psia-ft}^3} \times \frac{}{554.67 \text{ R}} \times \frac{65 \text{ lb}}{\text{lbmol}} \times \frac{60\%}{} \times \frac{10{,}000 \text{ ppmv}}{1{,}000{,}000} = 26{,}942 \text{ lbs/event}$$

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[3] Forced Ventilation losses are calculated using the correlation from page 17 of the TCEQ MSS guidance document - http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/mss/mss-guidance.pdf.

Forced Ventilation Losses (lb/hr) = 4.14 x 10^{-5} x (Pseudo Surface Velocity U_s)$^{0.78}$ x Vapor Pressure P_v x (Vapor Molecular Weight $M_{v)}$)$^{0.67}$ x (Liquid Heel Surface Area A_p)$^{0.94}$

Forced Ventilation Losses (lb/hr) =	4.14 x 10-5	0.001^0.78 m	10,000 ppmv	14.7 psia	101325 Pa	65^0.67 lb	5,028 m^2	= 8.67 lb/hr
		sec	1,000,000		14.7 psia	lbmol		

[4] Sludge Removal losses are calculated using the venting volumetric flow rate and venting concentration.

Sludge Removal Losses (lb/hr) = Vapor Pressure (psia) x Air Mover Volumetric Flow Rate (scfm) x 60 (min/hr) x Vapor Molecular Weight (lb/lbmol) x Air Mover Venting Concentration (ppmv)/1,000,000/(Ideal Gas Constant (psia-ft^3/lbmol-^{o}R) x Temperature (^{o}R))

Sludge Removal Losses (lb/hr) =	14.7 psia	100 scfm	60 min	65 lb	650 ppmv	lbmol-^{o}R		= 0.63 lb/hr
			hr	lbmol	1,000,000	10.73 psia-ft^3	554.67 R	

[5] Vacuum Truck Venting losses are calculated using the loading loss equation from AP-42, Section 5.2.

Vacuum Truck Venting Losses (lbs/event) = 12.46 x Saturation Factor x Vapor Pressure (psia) x Vapor Molecular Weight (lb/lbmol)/(Temperature (^{o}R)) x Vacuum Truck Usage (No. of 100 bbl trucks) x 100 (bbl/truck) x 42 (gal/bbl) / 1000

Vacuum Truck Venting Losses (lbs/event) =	12.46	0.6	11.00 psia	65 lb		20 trucks	100 bbl	42 gal	1	= 810 lbs/event
				lbmol	554.67 R		truck	bbl	1,000	

[6] Refilling Losses for drain-dry tanks are calculated using equation 2-26 from AP-42 Chapter 7.1, Table 7.1-19.

Refilling Losses (lbs/event) = Filling Saturation Factor x Vapor Space Volume (ft^3) x Vapor Pressure (psia) x Vapor Molecular Weight (lb/lbmol)/(Ideal Gas Constant (psia-ft^3/lbmol-^{o}R) x Temperature (^{o}R))

Refilling Losses (lbs/event) =	0.15	378,832 ft^3	11.00 psia	65 lb	lbmol-^{o}R		= 6,827 lbs/event
				lbmol	10.73 psia-ft^3	554.67 R	

[7] The volume of Slop Tank is assumed to be the same as Product tanks to be conservative.

Hourly and Annual VOC Emissions from Tank MSS Activities - Sludge Removal and Vacuum Truck Venting

Tank ID	Description	EPN	Controlled Sludge Removal Emissions [1]		Controlled Vacuum Truck Venting Emissions [2]		VOC Emissions [3]		Benzene Emissions [5]		H_2S Emissions [6]	
			Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)
TK-501	IFR Tank 501	TKS-MSS	0.06	0.01	4.05	0.16	4.05	0.17	0.02	7.35E-04	6.81E-05	3.42E-06
TK-502	IFR Tank 502	TKS-MSS	0.06	0.01	4.05	0.16	4.05	0.17	0.02	7.35E-04	6.81E-05	3.42E-06
TK-503	IFR Tank 503	TKS-MSS	0.06	0.01	4.05	0.16	4.05	0.17	0.02	7.35E-04	6.81E-05	3.42E-06
TK-504	IFR Tank 504	TKS-MSS	0.06	0.01	4.05	0.16	4.05	0.17	0.02	7.35E-04	6.81E-05	3.42E-06
TK-505	IFR Tank 505	TKS-MSS	0.06	0.01	4.05	0.16	4.05	0.17	0.02	7.35E-04	6.81E-05	3.42E-06
TK-506	IFR Tank 506	TKS-MSS	0.06	0.01	4.05	0.16	4.05	0.17	0.02	7.35E-04	6.81E-05	3.42E-06
TK-507	IFR Tank 507	TKS-MSS	0.06	0.01	4.05	0.16	4.05	0.17	0.02	7.35E-04	6.81E-05	3.42E-06
TK-508	IFR Tank 508	TKS-MSS	0.06	0.01	4.05	0.16	4.05	0.17	0.02	7.35E-04	6.81E-05	3.42E-06
TK-509	IFR Tank 509	TKS-MSS	0.06	0.01	4.05	0.16	4.05	0.17	0.02	7.35E-04	6.81E-05	3.42E-06
TK-510	IFR Tank 510	TKS-MSS	0.06	0.01	4.05	0.16	4.05	0.17	0.02	7.35E-04	6.81E-05	3.42E-06
TK-511	IFR Tank 511	TKS-MSS	0.06	0.01	4.05	0.16	4.05	0.17	0.02	7.35E-04	6.81E-05	3.42E-06
TK-512	IFR Tank 512	TKS-MSS	0.06	0.01	4.05	0.16	4.05	0.17	0.02	7.35E-04	6.81E-05	3.42E-06
TK-SLOP [7]	Slop Oil Tank	TKS-MSS	0.06	0.01	4.05	0.16	4.05	0.17	0.02	7.35E-04	6.81E-05	3.42E-06
						Total [4]	**4.05**	**0.17**	**0.02**	**7.35E-04**	**6.81E-05**	**3.42E-06**

[1] Controlled Sludge Removal Hourly Emissions (lb/hr) = Uncontrolled Sludge Removal Losses (lb/hr) x (1 - Control Eff. (%))

Controlled Sludge Removal Hourly Emissions (lb/hr) =	0.63 lbs	(1 - 0.9)	= 0.06 lb/hr
	event		

Controlled Sludge Removal Annual Emissions (tpy) = Uncontrolled Sludge Removal Losses (lb/hr) x Sludge Removal Duration (days/event) x 24 (hrs/day) x No. of events per year (events/yr) x (1 - Control Eff. (%)) x (1 ton/2,000 lbs)

Controlled Sludge Removal Annual Emissions (tpy) =	0.63 lbs	3 days	24 hrs	4 event	(1 - 0.9)	1 ton	= 0.01 tpy
	hr	event	day	yr		2,000 lbs	

[2] Controlled Vacuum Truck Venting Hourly Emissions (lb/hr) = Uncontrolled Vacuum Truck Venting Losses for (lbs/event) / Vacuum Truck Usage x (1 - Control Eff. (%))

Controlled Vacuum Truck Venting Hourly Emissions (lb/hr) =	810 lbs	1 event	(1 - 0.9)	= 4.05 lb/hr
	event	20 trucks-hr		

Controlled Vacuum Truck Venting Annual Emissions (tpy) = Uncontrolled Vacuum Truck Venting Losses (lbs/event) x No. of events per year (events/yr) x (1 - Control Eff. (%)) x (1 ton/2,000 lbs)

Controlled Vacuum Truck Venting Annual Emissions (tpy) =	810 lbs	4 event	(1 - 0.9)	1 ton	= 0.16 tpy
	event	yr		2,000 lbs	

[3] Hourly VOC Emissions (lb/hr) = MAX(Controlled Sludge Removal (lb/hr), Controlled Vacuum Truck Venting (lb/hr))
Annual VOC Emissions (tpy) = SUM(Controlled Sludge Removal (tpy), Controlled Vacuum Truck Venting (tpy))
[4] It is assumed that only one of the tank cleaning operations will occur within one hour on a tank by tank basis, and each tank will be cleaned up to four (4) times a year.
[5] Benzene Hourly Emissions (lb/hr) = Max Benzene % in Vapor x VOC Hourly Emissions (lb/hr)

Benzene Hourly Emissions (lb/hr) =	0.43%	4.05 lbs	= 0.02 lb/hr
		hr	

Benzene Annual Emissions (tpy) = Max Benzene % in Vapor x VOC Annual Emissions (tpy)

Benzene Annual Emissions (tpy) =	0.43%	0.17 tons	= 7.35E-4 tpy
		yr	

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[6] H_2S Hourly Emissions (lb/hr) = Max H_2S Mass Ratio (lb H_2S/lb VOC) x VOC Hourly Emissions (lb/hr)

$$H_2S \text{ Hourly Emissions (lb/hr)} = \frac{1.68E\text{-}05 \text{ lb H2S}}{\text{lb VOC}} \cdot \frac{4.05 \text{ lbs}}{\text{hr}} = 6.81E\text{-}05 \text{ lb/hr}$$

H_2S Annual Emissions (tpy) = Max H_2S Mass Ratio (lb H_2S/lb VOC) x VOC Annual Emissions (tpy)

$$H_2S \text{ Annual Emissions (tpy)} = \frac{1.68E\text{-}05 \text{ lb H2S}}{\text{lb VOC}} \cdot \frac{0.17 \text{ tons}}{\text{yr}} = 3.42E\text{-}6 \text{ tpy}$$

Hourly and Annual VOC Emissions from Tank MSS Activities - Standing Idle, Degassing, and Refilling

Tank ID	Description	EPN	Controlled Standing Idle Emissions [1]		Controlled Degassing Emissions [2]		Controlled Forced Ventilation Emissions [3]		Controlled Refilling Emissions [4]		VOC Emissions [5]		Benzene Emissions [6]	
			Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)
TK-501	IFR Tank 501	VCU-TKS	7.96E-03	3.82E-04	11.23	0.54	0.09	4.16E-03	5.06	0.14	11.23	0.68	0.05	2.91E-03
TK-502	IFR Tank 502	VCU-TKS	7.96E-03	3.82E-04	11.23	0.54	0.09	4.16E-03	5.06	0.14	11.23	0.68	0.05	2.91E-03
TK-503	IFR Tank 503	VCU-TKS	7.96E-03	3.82E-04	11.23	0.54	0.09	4.16E-03	5.06	0.14	11.23	0.68	0.05	2.91E-03
TK-504	IFR Tank 504	VCU-TKS	7.96E-03	3.82E-04	11.23	0.54	0.09	4.16E-03	5.06	0.14	11.23	0.68	0.05	2.91E-03
TK-505	IFR Tank 505	VCU-TKS	7.96E-03	3.82E-04	11.23	0.54	0.09	4.16E-03	5.06	0.14	11.23	0.68	0.05	2.91E-03
TK-506	IFR Tank 506	VCU-TKS	7.96E-03	3.82E-04	11.23	0.54	0.09	4.16E-03	5.06	0.14	11.23	0.68	0.05	2.91E-03
TK-507	IFR Tank 507	VCU-TKS	7.96E-03	3.82E-04	11.23	0.54	0.09	4.16E-03	5.06	0.14	11.23	0.68	0.05	2.91E-03
TK-508	IFR Tank 508	VCU-TKS	7.96E-03	3.82E-04	11.23	0.54	0.09	4.16E-03	5.06	0.14	11.23	0.68	0.05	2.91E-03
TK-509	IFR Tank 509	VCU-TKS	7.96E-03	3.82E-04	11.23	0.54	0.09	4.16E-03	5.06	0.14	11.23	0.68	0.05	2.91E-03
TK-510	IFR Tank 510	VCU-TKS	7.96E-03	3.82E-04	11.23	0.54	0.09	4.16E-03	5.06	0.14	11.23	0.68	0.05	2.91E-03
TK-511	IFR Tank 511	VCU-TKS	7.96E-03	3.82E-04	11.23	0.54	0.09	4.16E-03	5.06	0.14	11.23	0.68	0.05	2.91E-03
TK-512	IFR Tank 512	VCU-TKS	7.96E-03	3.82E-04	11.23	0.54	0.09	4.16E-03	5.06	0.14	11.23	0.68	0.05	2.91E-03
TK-SLOP [7]	Slop Oil Tank	VCU-TKS	7.96E-03	3.82E-04	11.23	0.54	0.09	4.16E-03	5.06	0.14	11.23	0.68	0.05	2.91E-03
										Total [5]	**11.23**	**0.68**	**0.05**	**2.91E-03**

[1] Controlled Standing Idle Hourly Emissions (lb/hr) = Uncontrolled Standing Idle Losses (lbs/event) / Standing Idle Duration (hrs/event) x (1 - VCU Control Eff. (%))

$$\text{Controlled Standing Idle Hourly Emissions (lb/hr)} = \frac{19.09 \text{ lbs}}{\text{event}} \cdot \frac{1 \text{ event}}{24 \text{ hrs}} \cdot (1 - 0.99) = 0.01 \text{ lb/hr}$$

Controlled Standing Idle Annual Emissions (tpy) = Uncontrolled Standing Idle Losses (lbs/event) x No. of events per year (events/yr) x (1 - VCU Control Eff. (%)) x (1 ton/2,000 lbs)

$$\text{Controlled Standing Idle Annual Emissions (tpy)} = \frac{19.09 \text{ lbs}}{\text{event}} \cdot \frac{4 \text{ event}}{\text{yr}} \cdot (1 - 0.99) \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lbs}} = 3.82E\text{-}04 \text{ tpy}$$

[2] Controlled Degassing Hourly Emissions (lb/hr) = Uncontrolled Degassing Losses (lbs/event) / Degassing Duration (hrs/event) x (1 -VCU Control Eff. (%))

$$\text{Controlled Degassing Hourly Emissions (lb/hr)} = \frac{26{,}942 \text{ lbs}}{\text{event}} \cdot \frac{1 \text{ event}}{24 \text{ hrs}} \cdot (1 - 0.99) = 11.23 \text{ lb/hr}$$

Controlled Degassing Annual Emissions (tpy) = Uncontrolled Degassing Losses (lbs/event) x No. of events per year (events/yr) x (1 - VCU Control Eff. (%)) x (1 ton/2,000 lbs)

$$\text{Controlled Degassing Annual Emissions (tpy)} = \frac{26{,}942 \text{ lbs}}{\text{event}} \cdot \frac{4 \text{ event}}{\text{yr}} \cdot (1 - 0.99) \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lbs}} = 0.54 \text{ tpy}$$

[3] Controlled Forced Ventilation Hourly Emissions (lb/hr) = Uncontrolled Forced Ventilation Losses (lbs/hr) x (1 - VCU Control Eff. (%))

$$\text{Controlled Forced Ventilation Hourly Emissions (lb/hr)} = \frac{8.67 \text{ lb}}{\text{hr}} \cdot (1 - 0.99) = 0.09 \text{ lb/hr}$$

Controlled Forced Ventilation Annual Emissions (tpy) = Controlled Forced Ventilation Losses (lb/hr) x Forced Ventilation Duration (hrs/event) x No. of events per year (events/yr) x (1 ton/2,000 lbs)

$$\text{Controlled Forced Ventilation Annual Emissions (tpy)} = \frac{0.09 \text{ lb}}{\text{hr}} \cdot \frac{24 \text{ hrs}}{\text{event}} \cdot \frac{4 \text{ events}}{\text{yr}} \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lbs}} = 4.16E\text{-}03 \text{ tpy}$$

[3] Controlled Refilling Hourly Emissions (lb/hr) = Uncontrolled Refilling Losses (lbs/event) / Refilling Duration (hrs/event) x (1 - VCU Control Eff. (%))

$$\text{Controlled Refilling Hourly Emissions (lb/hr)} = \frac{6{,}827 \text{ lbs}}{\text{event}} \cdot \frac{1 \text{ event}}{13 \text{ hrs}} \cdot (1 - 0.99) = 5.06 \text{ lb/hr}$$

Controlled Refilling Annual Emissions (tpy) = Uncontrolled Refilling Losses (lbs/event) x No. of events per year (events/yr) x (1 - VCU Control Eff. (%)) x (1 ton/2,000 lbs)

$$\text{Controlled Refilling Annual Emissions (tpy)} = \frac{6{,}827 \text{ lbs}}{\text{event}} \cdot \frac{4 \text{ event}}{\text{yr}} \cdot (1 - 0.99) \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lbs}} = 0.14 \text{ tpy}$$

[5] Controlled VOC Hourly Emissions (lb/hr) = MAX(Controlled Hourly Standing Idle (lb/hr), Degassing (lb/hr), Forced Ventilation (lb/hr), Refilling Losses (lb/hr))
Controlled VOC Annual Emissions (tpy) = SUM(Controlled Annual Standing Idle (tpy), Degassing (tpy), Forced Ventilation (tpy), Refilling Losses (tpy))

[6] Benzene Hourly Emissions (lb/hr) = Max Benzene % in Vapor x VOC Hourly Emissions (lb/hr)

$$\text{Benzene Hourly Emissions (lb/hr)} = 0.43\% \cdot \frac{11.23 \text{ lbs}}{\text{hr}} = 0.05 \text{ lb/hr}$$

Benzene Annual Emissions (tpy) = Max Benzene % in Vapor x VOC Annual Emissions (tpy)

$$\text{Benzene Annual Emissions (tpy)} = 0.43\% \cdot \frac{0.68 \text{ tons}}{\text{yr}} = 2.91E\text{-}3 \text{ tpy}$$

[7] It is assumed that only one of the tank cleaning operations will occur within one hour on a tank by tank basis, and a maximum of four tanks will be cleaned every year.

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Hourly and Annual NO_X, CO, PM, H_2S, and SO_2 Emissions Estimates from Tank MSS Activities

Parameter	Value	Unit
NO_X Emission Factor [1]	0.100	lb/MMBtu
CO Emission Factor [1]	0.2000	lb/MMBtu
$PM/PM_{10}/PM_{2.5}$ Emission Factor [2]	23.47	lb/MMscf
H_2S Max Vapor Fraction in Condensate [3]	2.40E-05	
Maximum Mass Ratio of H_2S in Condensate [4]	1.68E-05	lb H_2S/lb VOC
H_2S VCU DRE	99.00%	
H_2S Molecular Weight	34.1	lb/lbmole
SO_2 Molecular Weight	64.07	lb/lbmole
Product Heat of Combustion [5]	18,679	Btu/lb
Molar Volume	385.44	scf/lbmole

[1] NOx and CO emission factors are representative design emission factors.

[2] PM Emission Factor for Crude Oil = PM Emission Factor for Natural Gas Combustion (lb/MMscf) x (1/Natural Gas Heat of Combustion (Btu/scf)) x Crude Oil Heat of Combustion (Btu/lb) x Crude Oil Vapor MW (lb/lbmole) x (1/Molar Volume (scf/lbmole@68.33°F))

$$\text{PM Emission Factor} = \frac{7.6\text{ lb}}{\text{MMscf}} \cdot \frac{\text{scf}}{1{,}020\text{ Btu}} \cdot \frac{18{,}679\text{ Btu}}{\text{lb}} \cdot \frac{65\text{ lb}}{\text{lbmole}} \cdot \frac{\text{lbmole}}{385.44\text{ scf}} = 23.47\text{ lb/MMscf}$$

[3] Maximum H_2S vapor fraction is assumed to be 24 ppmv for sweet crude.

[4] H_2S Mass Ratio in Condensate (lb H_2S/lb VOC) = H_2S Vapor Fraction in Condensate x H_2S MW (lb/lbmole)/Condensate Vapor MW (lb/lbmole) x 14.7 psia/Vapor Pressure of Condensate (psia)

$$\text{Max } H_2S \text{ Mass Ratio in Condensate (lb } H_2S\text{/lb VOC)} = \frac{0.000024}{} \cdot \frac{34.1\text{ lb}}{\text{lbmole}} \cdot \frac{\text{lbmole}}{65\text{ lb}} \cdot \frac{14.7\text{ psia}}{11\text{ psia}} = 1.68\text{E-05 lb H2S/lb VOC}$$

[5] Product Heat of Combustion obtained from Table A1, Biomass Energy Data Book, Edition 4, 2011, Oak Ridge National Laboratory (Oak Ridge, TN).

Tank ID	Description	EPN	Uncontrolled VOC Hourly Emissions [1] (lb/hr)	Uncontrolled VOC Annual Emissions [2] (tpy)	NO_X Hourly Emissions [3] (lb/hr)	NO_X Annual Emissions [4] (tpy)	CO Hourly Emissions [3] (lb/hr)	CO Annual Emissions [4] (tpy)	$PM/PM_{10}/PM_{2.5}$ Hourly Emissions [5][6] (lb/hr)	$PM/PM_{10}/PM_{2.5}$ Annual Emissions [5][7] (tpy)	H_2S Hourly Emissions [8] (lb/hr)	H_2S Annual Emissions [9] (tpy)	SO_2 Hourly Emissions [10] (lb/hr)	SO_2 Annual Emissions [10] (tpy)
TK-501	IFR Tank 501	VCU-TKS	1,123	67.99	2.10	0.13	4.19	0.25	0.16	9.46E-03	1.89E-04	1.36E-05	0.04	2.56E-03
TK-502	IFR Tank 502	VCU-TKS	1,123	67.99	2.10	0.13	4.19	0.25	0.16	9.46E-03	1.89E-04	1.36E-05	0.04	2.56E-03
TK-503	IFR Tank 503	VCU-TKS	1,123	67.99	2.10	0.13	4.19	0.25	0.16	9.46E-03	1.89E-04	1.36E-05	0.04	2.56E-03
TK-504	IFR Tank 504	VCU-TKS	1,123	67.99	2.10	0.13	4.19	0.25	0.16	9.46E-03	1.89E-04	1.36E-05	0.04	2.56E-03
TK-505	IFR Tank 505	VCU-TKS	1,123	67.99	2.10	0.13	4.19	0.25	0.16	9.46E-03	1.89E-04	1.36E-05	0.04	2.56E-03
TK-506	IFR Tank 506	VCU-TKS	1,123	67.99	2.10	0.13	4.19	0.25	0.16	9.46E-03	1.89E-04	1.36E-05	0.04	2.56E-03
TK-507	IFR Tank 507	VCU-TKS	1,123	67.99	2.10	0.13	4.19	0.25	0.16	9.46E-03	1.89E-04	1.36E-05	0.04	2.56E-03
TK-508	IFR Tank 508	VCU-TKS	1,123	67.99	2.10	0.13	4.19	0.25	0.16	9.46E-03	1.89E-04	1.36E-05	0.04	2.56E-03
TK-509	IFR Tank 509	VCU-TKS	1,123	67.99	2.10	0.13	4.19	0.25	0.16	9.46E-03	1.89E-04	1.36E-05	0.04	2.56E-03
TK-510	IFR Tank 510	VCU-TKS	1,123	67.99	2.10	0.13	4.19	0.25	0.16	9.46E-03	1.89E-04	1.36E-05	0.04	2.56E-03
TK-511	IFR Tank 511	VCU-TKS	1,123	67.99	2.10	0.13	4.19	0.25	0.16	9.46E-03	1.89E-04	1.36E-05	0.04	2.56E-03
TK-512	IFR Tank 512	VCU-TKS	1,123	67.99	2.10	0.13	4.19	0.25	0.16	9.46E-03	1.89E-04	1.36E-05	0.04	2.56E-03
TK-SLOP [7]	Slop Oil Tank	VCU-TKS	1,123	67.99	2.10	0.13	4.19	0.25	0.16	9.46E-03	1.89E-04	1.36E-05	0.04	2.56E-03
				Total [11]	**2.10**	**0.13**	**4.19**	**0.25**	**0.16**	**9.46E-03**	**1.89E-04**	**1.36E-05**	**0.04**	**2.56E-03**

[1] Uncontrolled Hourly VOC Emissions (lb/hr) = MAX(Uncontrolled Hourly Standing Idle (lb/hr), Degassing (lb/hr), Forced Ventilation (lb/hr), Refilling Emissions (lb/hr))

[2] Uncontrolled Annual VOC Emissions (tpy) = SUM(Uncontrolled Annual Standing Idle (tpy), Degassing (tpy), Forced Ventilation (tpy), Refilling Emissions (tpy))

[3] NO_X and CO Hourly Emissions (lb/hr) = Uncontrolled VOC Emissions (lb/hr) x NO_X or CO Emission Factor (lb/MMBtu) x Product Heat of Combustion (Btu/lb) x (1 MMBtu/1,000,000 Btu)

$$NO_X \text{ Hourly Emissions (lb/hr)} = \frac{1{,}123\text{ lb}}{\text{hr}} \cdot \frac{0.1\text{ lb}}{\text{MMBtu}} \cdot \frac{18{,}679\text{ Btu}}{\text{lb}} \cdot \frac{1\text{ MMBtu}}{1{,}000{,}000\text{ Btu}} = 2.10\text{ lb/hr}$$

[4] NO_X and CO Annual Emissions (tpy) = Uncontrolled VOC Emissions (tpy) x NO_X or CO Emission Factor (lb/MMBtu) x Product Heat of Combustion (Btu/lb) x (1 MMBtu/1,000,000 Btu)

$$NO_X \text{ Annual Emissions (tpy)} = \frac{67.99\text{ tons}}{\text{yr}} \cdot \frac{0.1\text{ lb}}{\text{MMBtu}} \cdot \frac{18{,}679\text{ Btu}}{\text{lb}} \cdot \frac{1\text{ MMBtu}}{1{,}000{,}000\text{ Btu}} = 0.13\text{ tpy}$$

[5] Hourly and Annual emissions of Total PM = PM_{10} = $PM_{2.5}$.

[6] PM Hourly Emissions (lb/hr) = Uncontrolled VOC Emissions (lb/hr) x (1/Vapor MW (lb/lbmole)) x Molar Volume (scf/lbmole) x Emission Factor (lb/MMscf) x (1 MMscf/1,000,000 scf)

$$\text{PM Hourly Emissions (lb/hr)} = \frac{1{,}123\text{ lb}}{\text{hr}} \cdot \frac{\text{lbmole}}{65\text{ lb}} \cdot \frac{385.44\text{ scf}}{\text{lbmole}} \cdot \frac{23.47\text{ lb}}{\text{MMscf}} \cdot \frac{1\text{ MMscf}}{1{,}000{,}000\text{ scf}} = 0.16\text{ lb/hr}$$

[7] PM Annual Emissions (tpy) = Uncontrolled VOC Emissions (tpy) x (1/Vapor MW (lb/lbmole)) x Molar Volume (scf/lbmole) x Emission Factor (lb/MMscf) x (1 MMscf/1,000,000 scf)

$$\text{PM Annual Emissions (tpy)} = \frac{67.99\text{ tons}}{\text{yr}} \cdot \frac{\text{lbmole}}{65\text{ lb}} \cdot \frac{385.44\text{ scf}}{\text{lbmole}} \cdot \frac{23.47\text{ lb}}{\text{MMscf}} \cdot \frac{1\text{ MMscf}}{1{,}000{,}000\text{ scf}} = 9.46\text{E-03 tpy}$$

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
Internal Floating Roof Tanks MSS Emissions - Condensate

[8] H_2S Hourly Emissions (lb/hr) = Max H_2S Mass Ratio (lb H_2S/lb VOC) x Uncontrolled VOC Emissions (lb/hr) x (1 - H_2S VCU DRE (%))

$$H_2S \text{ Hourly Emissions (lb/hr)} = \frac{1.68E\text{-}05 \text{ lb H2S}}{\text{lb VOC}} \times \frac{1{,}123 \text{ lb}}{\text{hr}} \times (1 - 0.99) = 1.89E\text{-}04 \text{ lb/hr}$$

[9] H_2S Annual Emissions (tpy) = Max H_2S Mass Ratio (lb H_2S/lb VOC) x Uncontrolled VOC Emissions (tpy) x (1 - H_2S VCU DRE (%))

$$H_2S \text{ Annual Emissions (tpy)} = \frac{1.68E\text{-}05 \text{ lb H2S}}{\text{lb VOC}} \times \frac{67.99 \text{ tons}}{\text{yr}} \times (1 - 0.99) = 1.36E\text{-}5 \text{ tpy}$$

[10] SO_2 emissions assume 100% of Uncontrolled H_2S emissions

[11] It is assumed that only one of the tank cleaning operations will occur within one hour on a tank by tank basis, and a maximum of four tanks will be cleaned every year.

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
EPN P-MSS / FIN P-MSS
Pipeline MSS Emissions Calculations

Basis for Pig Loading: AP-42, Section 5.2, Transportation and Marketing of Petroleum Liquids, July 2008.

$$L_L = \frac{12.46 \times S \times M \times P}{T}$$

L_L = Loading Losses (lb/1000 gal)
S = Saturation factor from Table 5.2-1
M = Vapor molecular weight of liquid loaded (lb/lb-mol)
P = True vapor pressure of liquid loaded (psia)
T = Temperature of bulk liquid loaded (°R)

Basis for Clingage Loss:
Clingage Loss = SA x C x Wl
SA = Clingage Surface Area (ft^2)
C = Clingage Thickness (ft)
Wl = Liquid density (lb/ft^3)

Basis for Pig Vapor Loss:
Vapor Space Loss = V x Wv
V = Vapor Space Volume (ft^3)
Wv = Vapor density (lb/ft^3)

Pipeline MSS Parameters

Parameter	Value	Unit
Material	Crude Oil/Condensate	
Saturation Factor	0.6	
Vapor MW	50.00	(lb/lb-mol)
TVP	11	(psia)
Temperature	554.67	(°R)
Liquid Density	53.11	(lb/ft^3)
VOC in Vapor	100%	(wt%)
Max. Benzene % in Vapor (RVP 11)	1.0%	
Maximum Mass Ratio of H_2S in Crude Oil	2.19E-05	lb H_2S/lb VOC
Pipeline Length	10	ft
Pipeline Diameter	16	inches

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
EPN P-MSS / FIN P-MSS
Pipeline MSS Emissions Calculations

Pig Loading Emissions

Volume Loaded[1] (gallons/event)	Event Frequency (events/yr)	L_L (lb/1000 gal)	VOC Hourly Emissions[2] (lb/hr)	VOC Annual Emissions (tpy)	H_2S Hourly Emissions[2] (lb/hr)	H_2S Annual Emissions (tpy)	Benzene Hourly Emissions[2] (lb/hr)	Benzene Annual Emissions (tpy)
104	1	7.4	0.77	3.87E-04	1.69E-05	8.47E-09	7.36E-03	3.68E-06

[1] It is assumed that no more than one pig trap will be filled each hour.
[2] It is assumed that all emissions from the event will be released within one hour.

Clingage Emissions

Clingage Surface Area[1] (ft^2)	Clingage Thickness[2] (in)	Event Frequency (events/yr)	Clingage Loss (lb/event)	VOC Hourly Emissions[3] (lb/hr)	VOC Annual Emissions (tpy)	H_2S Hourly Emissions[3] (lb/hr)	H_2S Annual Emissions (tpy)	Benzene Hourly Emissions[3] (lb/hr)	Benzene Annual Emissions (tpy)
89.36	0.0004	1	0.16	0.16	7.91E-05	3.46E-06	1.73E-09	1.50E-03	7.51E-07

[1] The internal surface area of the pig trap is conservatively doubled to account for clingage on the pig.
[2] Clingage thickness obtained from TCEQ *MSS Guidance* document.
[3] It is assumed that all emissions from the event will be released within one hour.

Pig Trap Vapor Emissions

Vapor Space Volume[1] (ft^3)	Molar Density (lb-mole/ft^3)	Vapor Density (lb/ft^3)	Event Frequency (events/yr)	Vapor Space Loss (lb/event)	VOC Hourly Emissions[2] (lb/hr)	VOC Annual Emissions (tpy)	H_2S Hourly Emissions[2] (lb/hr)	H_2S Annual Emissions (tpy)	Benzene Hourly Emissions[2] (lb/hr)	Benzene Annual Emissions (tpy)
13.96	0.0025	0.092	1	1.3	1.29	6.45E-04	2.82E-05	1.41E-08	0.01	6.13E-06
Total Pig Loading, Clingage, and Pig Trap Vapor Emissions:					**2.22**	**1.11E-03**	**4.86E-05**	**2.43E-08**	**0.02**	**1.06E-05**

[1] The volume of the pig trap is conservatively used for the vapor space volume.
[2] It is assumed that all emissions from the event will be released within one hour.

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
Oil-water Separator Emissions Calculation

Materials Properties

Material	Product	Universal Gas Law Constant (psia-ft^3/lbmol-°R)	Vapor Molecular Weight (lb/lb-mol)	Maximum True Vapor Pressure[2] (psia)	Worst Case Temperature[2] (°R)	Atmospheric Pressure (psia)	Standard Temperature (°R)
Water Draw[1]	Crude/Condensate	10.73	65.00	11.00	533.17	14.7	519.67

[1] Water draw is primarily water with a layer of crude oil or condensate at the top. Therefore, the material vapor properties are conservatively assumed to be the properties of crude oil. For hourly emission estimates, the worst-case marine loading commodity between Crude oil and Condensate will be utilized.

[2] Maximum true vapor pressure for Crude oil and Condensate obtained from information provided by Texas Gulf Terminals.

Oil-water Separator Physical Properties

EPN	Description	Capacity (gal)	Width (ft)	Height (ft)	Length (ft)	Maximum Flow Rate (gpm)	Annual Throughput[1] (gal/yr)
OWS	Oil-water Separator	53,860	20	6	60	5,000	252,000,000

[1] Annual throughput based on the volume of water drawn from 12 storage tanks per year. Height is assumed to be 6 ft. Other details provided by Lloyd Engineering, Inc. to TGTI/ Trinity Consultants on June 12 2018.

Oil-water Separator Operating Parameters

EPN	Description	Hourly Volume[1] (scf/hr)	Annual Volume Due to OWS Breathing[2] (scf/yr)	Annual Volume Due to OWS Loading[3] (scf/yr)	Annual VOC Mass Due to OWS Loading[4] (lb/yr)	Total Annual Volume[5] (scf/yr)
OWS	Oil-water Separator	39,089	304,935	32,834,524	4,209,872	33,139,459

[1] Hourly Volume (scf/hr) = Hourly Throughput (gpm) / 7.48 (gal/ft^3) x 60 (min/hr) x Standard Temperature (°R) / Worst-case Temperature (°R)

$$\text{Hourly Volume} = \frac{5000\ \text{gallon}}{\text{minute}} \cdot \frac{\text{ft}^3}{7.48\ \text{gal}} \cdot \frac{60\ \text{minute}}{\text{hour}} \cdot \frac{519.67\ °\text{R}}{533.17\ °\text{R}} = 39{,}089\ \text{scf/hr}$$

[2] Calculations are presented in next page - Oil-water Separator Emissions Calculation.

[3] Annual Volume Due to OWS Loading (scf/yr) = Annual Throughput (gal/yr) / 7.48 (gal/ft^3) x Standard Temperature (°R) / Worst-case Temperature (°R)

$$\text{Annual Volume Purged Due to OWS Loading} = \frac{252{,}000{,}000\ \text{gal}}{\text{yr}} \cdot \frac{\text{ft}^3}{7.48\ \text{gal}} \cdot \frac{519.67\ °\text{R}}{533.17\ °\text{R}} = 32{,}834{,}524\ \text{scf/yr}$$

[4] Annual VOC mass due to OWS loading is calculated with ideal gas law equation.

[5] Total Annual Volume (scf/yr) = Annual Volume Due to OWS Loading (scf/yr) + Annual Volume Due to OWS Breathing (scf/yr)

Oil-water Separator Emissions Calculation

EPN	Description	VOC Concentration at Breakthrough[2]	Hourly VOC Emissions[1]	Annual VOC Emissions[1]	H_2S Mass Ratio in Vapor[2]	Hourly H_2S Emissions[3]	Annual H_2S Emissions[3]	Hourly Benzene Emissions[4]	Annual Benzene Emissions[4]
		(ppmv)	(lb/hr)	(tpy)	(lb H_2S/lb VOC)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
OWS	Oil-water Separator	100	0.67	0.28	2.19E-05	1.46E-05	6.21E-06	0.01	2.70E-03

[1] VOC Emissions are calculated using the ideal gas law.

$$\text{Emissions (lbs)} = \frac{P \times V \times MW}{R \times T}$$

Where, R = Universal Gas Law Constant (psia-ft^3/lbmol-°R)
V = Volume Purged to Carbon Canisters (scf)
M = Vapor Molecular Weight of Liquid Loaded (lb/lb-mol)
P = Atmospheric Pressure (psia)
T = Standard Temperature (°R)

[2] H_2S mass ratio in crude oil vapor for storage tank is used to be conservative. VOC Concentration is assumed.

[3] H_2S Emissions = Max H_2S Mass Ratio (lb H_2S/lb VOC) x Uncontrolled VOC Emissions

$$H_2S\ \text{Hourly Emissions (lb/hr)} = \frac{2.19\text{E-}05\ \text{lb H2S}}{\text{lb VOC}} \cdot \frac{0.67\ \text{lb}}{\text{hr}} = 6.77\text{E-}01\ \text{lb/hr}$$

[4] Benzene emissions are based on worse case crude vapor phase concentration of 0.95%.

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
Oil-water Separator Emissions Calculation

Calculation performed in accordance with AP-42, November 2006, Section 7.1.3.1.

Variable	
Tank Identification	***Oil-water Separator***
CIN	***N/A***
Discharging to	***Atmosphere***
EPN	***OWS***
Location for Calculation Purposes	**Corpus Christi, Texas**
Tank/Roof Type	**Horizontal Tank**
Underground?	**Aboveground**
Shell Paint Color	**White**
Shell Paint Condition	**Good**
Roof Paint Color	**White**
Roof Paint Condition	**Good**

	January	February	March	April	May	June	July	August	September	October	November	December
Type of Substance	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**
Contents of Tank	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**
Effective Diameter, ft	39.09	39.09	39.09	39.09	39.09	39.09	39.09	39.09	39.09	39.09	39.09	39.09
Effective Height, ft	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00
Working Capacity, gal	53,860	53,860	53,860	53,860	53,860	53,860	53,860	53,860	53,860	53,860	53,860	53,860
Maximum Liquid Height, ft	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Minimum Liquid Height, ft	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Average Liquid Height, ft	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Vapor Space Outage, ft	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00
Vapor Space Volume, ft^3	7200	7200	7200	7200	7200	7200	7200	7200	7200	7200	7200	7200
Average Daily Minimum Ambient Temperature, F	45.30	48.00	55.30	63.20	69.50	73.40	74.80	75.00	72.30	63.90	55.60	48.40
Average Daily Maximum Ambient Temperature, F	65.00	69.00	75.70	81.70	86.20	90.40	93.30	93.40	89.70	83.90	75.80	68.30
Daily Total Solar Insolation Factor, Btu/ft^2/day	886	1132	1404	1598	1734	1929	1987	1852	1599	1367	1043	843
Daily Average Ambient Temperature, F	55.2	58.5	65.5	72.5	77.9	81.9	84.1	84.2	81.0	73.9	65.7	58.4
Tank Paint Solar Absorbance, dimensionless	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Daily Vapor Temperature Range, R	18.4	20.5	21.4	20.9	20.3	21.4	22.8	22.1	20.1	20.9	19.5	18.3
Daily Average Liquid Surf. Temperature, F	56.4	60.0	67.4	74.6	80.2	84.5	86.7	86.7	83.2	75.7	67.1	59.5
Daily Minimum Liquid Surf. Temperature, F	51.8	54.9	62.1	69.4	75.1	79.1	81.0	81.2	78.1	70.5	62.2	54.9
Daily Maximum Liquid Surf. Temperature, F	61.0	65.2	72.7	79.8	85.3	89.9	92.4	92.2	88.2	81.0	72.0	64.1
Liquid Bulk Temperature	55.2	58.5	65.5	72.5	77.9	81.9	84.1	84.2	81.0	73.9	65.7	58.4
Vapor Pressure at Daily Av. Liquid Surf. Temp., psia	8.76	8.70	8.67	8.69	8.72	8.68	8.64	8.67	8.73	8.70	8.74	8.77
Vapor Pressure at Daily Min. Liquid Surf. Temp., psia	8.13	8.00	7.95	7.99	8.04	7.97	7.89	7.94	8.06	8.00	8.08	8.14
Vapor Pressure at Daily Max. Liquid Surf. Temp., psia	9.42	9.43	9.43	9.44	9.44	9.45	9.44	9.45	9.45	9.44	9.44	9.43
Daily Vapor Pressure range, psi	1.2913	1.4284	1.4790	1.4456	1.4006	1.4723	1.5574	1.5125	1.3906	1.4443	1.3586	1.2862
Breather Vent Pressure Setting, psig	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300
Breather Vent Vacuum Setting, psig	-0.0300	-0.0300	-0.0300	-0.0300	-0.0300	-0.0300	-0.0300	-0.0300	-0.0300	-0.0300	-0.0300	-0.0300
Breather Vent Pressure Setting Range, psi	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600
Ambient Pressure, psia	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Vapor Space Expansion Factor	0.2429	0.2674	0.2759	0.2697	0.2617	0.2742	0.2887	0.2811	0.2600	0.2696	0.2549	0.2421
Vented Vapor Saturation Factor	0.2642	0.2656	0.2662	0.2657	0.2651	0.2658	0.2669	0.2662	0.2648	0.2656	0.2646	0.2639
Volume of Material Purged Due to Diurnal Heating, ft^3/mo	14,323	14,316	16,389	15,481	15,483	15,742	17,197	16,706	14,871	15,983	14,568	14,262
Volume of Air Purged Due to Diurnal Heating, ft^3/mo	24,039	24,200	27,787	26,185	26,104	26,645	29,268	28,337	25,041	27,016	24,507	23,906
Volume of Air Purged Due to Diurnal Heating, scf/mo	24,209	24,198	27,397	25,469	25,128	25,445	27,837	26,952	23,972	26,222	24,177	23,930

Sample Calculations for Estimating Monthly Volume from Fixed Roof Tanks

Calculations are performed in accordance with the calculation methodology for fixed roof tanks explained in EPA AP-42 Chapter 7 for Organic Liquid Storage Tanks.

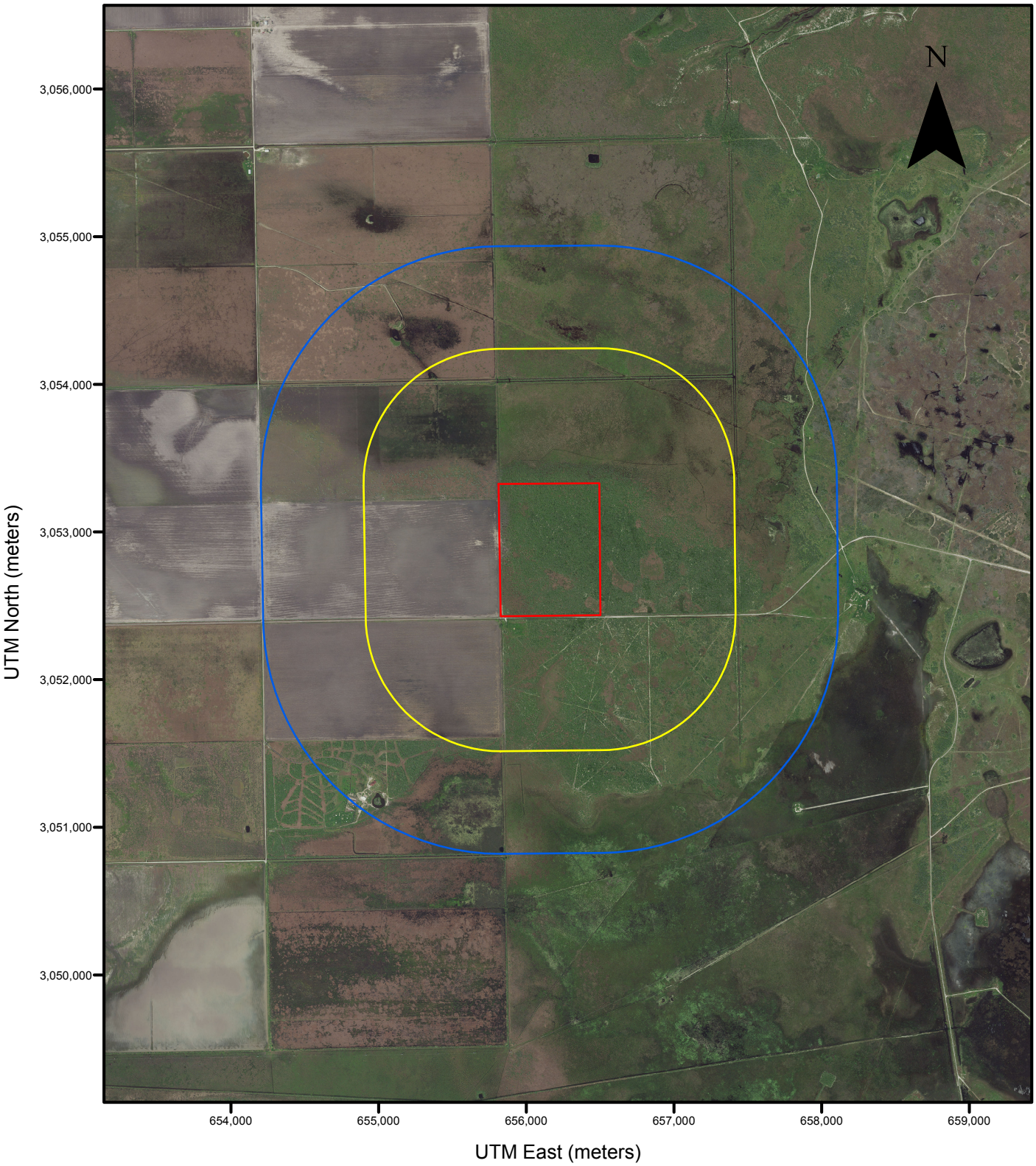
Worst-case Month	July

	Where:	Value	
[VM] = [MD] x [VV] x [KE] x [KS]	VM	17,197	Volume of Material Purged Due to Diurnal Heating, ft^3/mo
	MD	31	Days in month
[VA] = [VM] / [PVM] x [PVA]	VV	7,200	Vapor Space Volume, ft^3
	KE	0.2887	Vapor Space Expansion Factor
[VAS] = [VA] / [TA] x [TS]	KS	0.2669	Vented Vapor Saturation Factor
	VA	29,268	Volume of Air Purged Due to Diurnal Heating, ft^3/mo
[VM] = [31] x [7,200] x [0.2887] x [0.2669] = 17,197 ft^3/mo	PVM	8.64	Vapor Pressure at Daily Av. Liquid Surf. Temp., psia
	PVA	14.70	Ambient Pressure, psia
[VA] = [17,197] / [8.64] x [14.70] = 29,268 ft^3/mo	VAS	27,837	Volume of Air Purged Due to Diurnal Heating, scf/mo
	TA	546.40	Daily Average Liquid Surf. Temperature, R
[VAS] = [29,268] / [546.40] x [519.67] = 27,837 scf/mo	TS	519.67	Standard Temperature, R

APPENDIX C: AREA MAP AND PLOT PLAN

Texas Gulf Terminals Inc.

Area Map



Scale

0 500 1,000 1,500 2,000

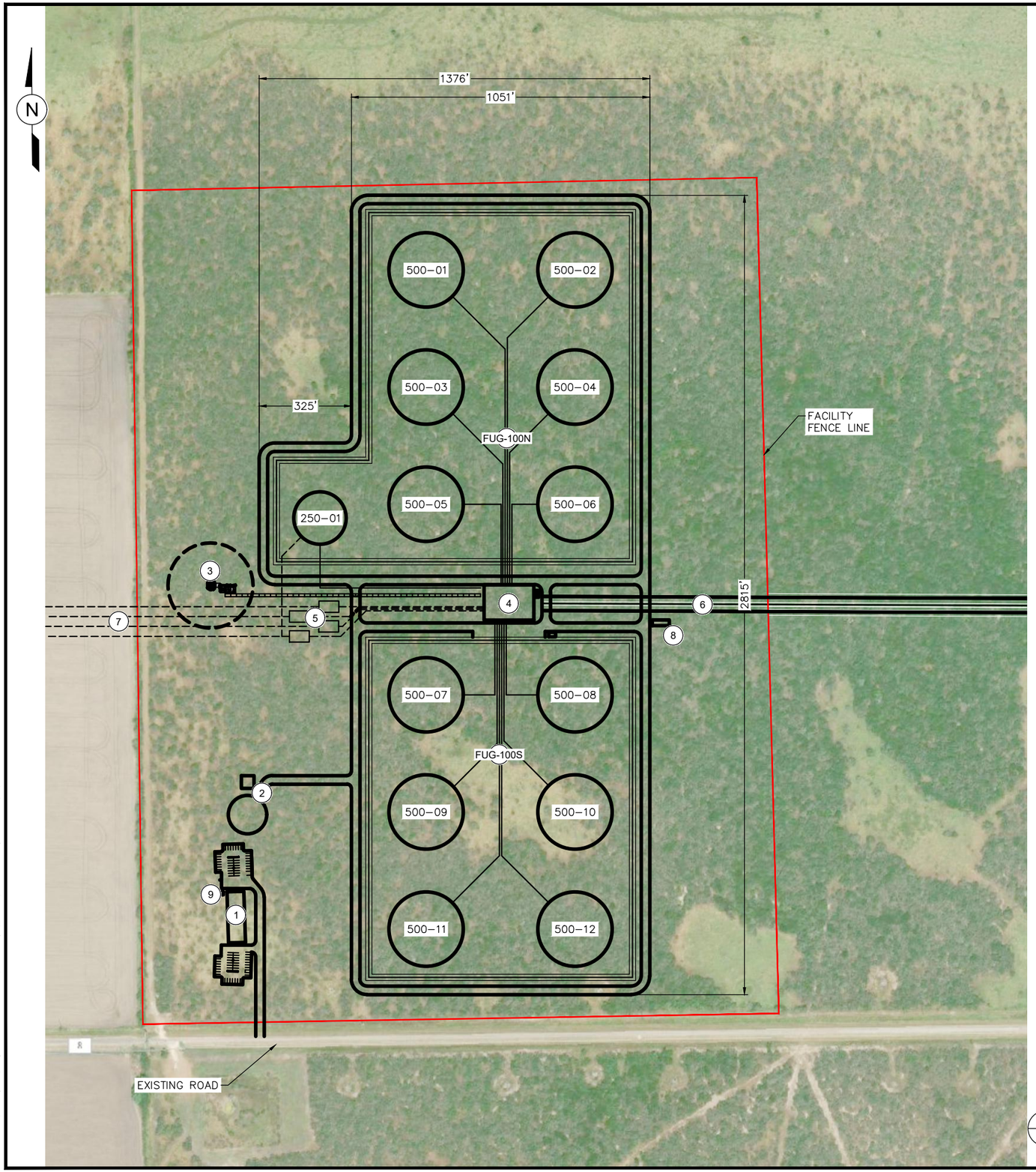
Meters

Legend

- Property Boundary
- 3000 ft Buffer
- 1 mile Buffer

Coordinate System: NAD83 UTM Zone 14N
Map: NAIP 2014 Nueces County Mosaic
Date: 06-15-2018

Trinity Consultants



Emission Point	Center Point Coordinates			
	Lat	Lon	Tx St Plane	
			Northing	Easting
Tank 500-01	27°35'39.00"N	97°25'05.19"W	17106306.549	1334662.443
Tank 500-02	27°35'38.96"N	97°24'59.36"W	17106306.549	1335187.443
Tank 500-03	27°35'34.92"N	97°25'05.23"W	17105894.049	1334662.443
Tank 500-04	27°35'34.88"N	97°24'59.40"W	17105894.049	1335187.443
Tank 500-05	27°35'30.84"N	97°25'05.27"W	17105481.549	1334662.443
Tank 500-06	27°35'30.79"N	97°24'59.44"W	17105481.549	1335187.443
Tank 500-07	27°35'24.19"N	97°25'05.34"W	17104810.049	1334662.443
Tank 500-08	27°35'24.14"N	97°24'59.50"W	17104810.049	1335187.443
Tank 500-09	27°35'20.10"N	97°25'05.38"W	17104397.549	1334662.443
Tank 500-10	27°35'20.06"N	97°24'59.54"W	17104397.549	1335187.443
Tank 500-11	27°35'16.02"N	97°25'05.42"W	17103985.049	1334662.443
Tank 500-12	27°35'15.97"N	97°24'59.58"W	17103985.049	1335187.443
Tank 250-01	27°35'30.38"N	97°25'09.43"W	17105432.799	1334288.693
FUG-100N	27°35'32.61"N	97°25'02.16"W	17105663.522	1334940.917
FUG-100S	27°35'22.52"N	97°25'02.44"W	17104643.702	1334924.943
FUG-200	27°35'27.37"N	97°25'02.06"W	17105134.333	1334954.504
FUG-300	27°35'26.80"N	97°25'09.70"W	17105071.127	1334267.730
VCU-01	27°35'28.07"N	97°25'13.74"W	17105195.367	1333902.669
FWP-01	27°35'20.98"N	97°25'12.11"W	17104480.655	1334056.237
OWS-01	27°35'26.53"N	97°24'56.12"W	17105054.032	1335489.343
GEN-01	27°35'17.28"N	97°25'13.41"W	17104106.216	1333942.365

LEGEND

1. ADMIN / OPERATIONS BLDG,.
2. FIRE PUMP AND FIREWATER TANK / FWP-01
3. VCU-01
4. MANIFOLD / FUG-200
5. METER SKIDS / FUG 300
6. (2) 30" PIPELINES TO OUTBOUND
7. (4) INBOUND/OUTBOUND PIPELINES
8. OILY WATER SEPARATOR / OWS-01
9. GENERATOR / GEN-01

AREAS
TOTAL SITE 150.0 ACRES
NORTH TANK FARM 27.7 ACRES
SOUTH TANK FARM 24.3 ACRES

ONSHORE STORAGE TERMINAL FACILITY
1"=200'

NO.	DESCRIPTION	DATE	APPR
A	ISSUED FOR PERMIT	06/22/18	POP

ISSUED FOR PERMIT

TEXAS GULF TERMINALS INC.

TEXAS GULF TERMINALS PROJECT

ONSHORE STORAGE TERMINAL FACILITY

LLOYD ENGINEERING, INC
HOUSTON TEXAS USA
LICENSE NO. F-002846

DESIGN BY:	SL
DRAWN BY:	–
DATE:	02–21–2018
SCALE:	AS NOTED @ 22"X34"
SHEET:	10 OF 47
DRAWING NO:	
REV. A	10

FILE NAME: L:\LEI Projects\Trafigura\OFFSHORE CORPUS\6.0 Drawings_Master\TankFarmGA.dwg PLOTTED: 6/14/2018 5:19:01 PM USER: RALF CABALLERO

APPENDIX D: CORE DATA FORM

TCEQ Use Only

TCEQ Core Data Form

For detailed instructions regarding completion of this form, please read the Core Data Form Instructions or call 512-239-5175.

SECTION I: General Information

1. Reason for Submission *(If other is checked please describe in space provided.)*

☐ New Permit, Registration or Authorization (*Core Data Form should be submitted with the program application.)*

☐ Renewal *(Core Data Form should be submitted with the renewal form)* ☒ Other

2. Customer Reference Number *(if issued)*	Follow this link to search for CN or RN numbers in Central Registry**	3. Regulated Entity Reference Number *(if issued)*
CN **605490085**		RN **110317666**

SECTION II: Customer Information

4. General Customer Information | 5. Effective Date for Customer Information Updates (mm/dd/yyyy)

☐ New Customer ☒ Update to Customer Information ☐ Change in Regulated Entity Ownership
☐ Change in Legal Name (Verifiable with the Texas Secretary of State or Texas Comptroller of Public Accounts)

The Customer Name submitted here may be updated automatically based on what is current and active with the Texas Secretary of State (SOS) or Texas Comptroller of Public Accounts (CPA).

6. Customer Legal Name *(If an individual, print last name first: eg: Doe, John)* | *If new Customer, enter previous Customer below:*

Texas Gulf Terminals Inc

7. TX SOS/CPA Filing Number	8. TX State Tax ID (11 digits)	9. Federal Tax ID (9 digits)	10. DUNS Number *(if applicable)*
802978324		824956693	

11. Type of Customer: ☒ Corporation ☐ Individual Partnership: ☐ General ☐ Limited
Government: ☐ City ☐ County ☐ Federal ☐ State ☐ Other ☒ Sole Proprietorship ☐ Other:

12. Number of Employees
☐ 0-20 ☐ 21-100 ☐ 101-250 ☐ 251-500 ☐ 501 and higher

13. Independently Owned and Operated?
☐ Yes ☒ No

14. Customer Role (Proposed or Actual) – *as it relates to the Regulated Entity listed on this form. Please check one of the following:*

☐ Owner ☐ Operator ☒ Owner & Operator
☐ Occupational Licensee ☐ Responsible Party ☐ Voluntary Cleanup Applicant ☐ Other:

15. Mailing Address:							
	1401 MCKINNEY ST STE 1500						
	City	HOUSTON	State	TX	ZIP	77010	ZIP + 4

16. Country Mailing Information *(if outside USA)*	17. E-Mail Address *(if applicable)*
	Denise-Rogers@Texasgulfterminals.com

18. Telephone Number	19. Extension or Code	20. Fax Number *(if applicable)*
(832) 203-6493		( ) -

SECTION III: Regulated Entity Information

21. General Regulated Entity Information *(If 'New Regulated Entity" is selected below this form should be accompanied by a permit application)*

☐ New Regulated Entity ☐ Update to Regulated Entity Name ☒ Update to Regulated Entity Information

The Regulated Entity Name submitted may be updated in order to meet TCEQ Agency Data Standards (removal of organizational endings such as Inc, LP, or LLC.)

22. Regulated Entity Name *(Enter name of the site where the regulated action is taking place.)*

TGTI Onshore Terminal

23. Street Address of the Regulated Entity: *(No PO Boxes)*								
	City		State		ZIP		ZIP + 4	
24. County	NUECES							

Enter Physical Location Description if no street address is provided.

25. Description to Physical Location:	Located 1 mile east, from the intersection of County Road 80 and County Road 43

26. Nearest City	State	Nearest ZIP Code
Corpus Christi	TX	78418

27. Latitude (N) In Decimal:	27.590843°		28. Longitude (W) In Decimal:	-97.417691°	
Degrees	Minutes	Seconds	Degrees	Minutes	Seconds

29. Primary SIC Code (4 digits)	30. Secondary SIC Code (4 digits)	31. Primary NAICS Code (5 or 6 digits)	32. Secondary NAICS Code (5 or 6 digits)

33. What is the Primary Business of this entity? *(Do not repeat the SIC or NAICS description.)*

CRUDE OIL AND CONDENSATE STORAGE

34. Mailing Address:	1401 MCKINNEY ST STE 1500							
	City	HOUSTON	State	TX	ZIP	77010	ZIP + 4	

35. E-Mail Address:	DENISE-ROGERS@TEXASGULFTERMINALS.COM

36. Telephone Number	37. Extension or Code	38. Fax Number *(if applicable)*
(832) 203-6493		( ) -

39. TCEQ Programs and ID Numbers Check all Programs and write in the permits/registration numbers that will be affected by the updates submitted on this form. See the Core Data Form instructions for additional guidance.

☐ Dam Safety	☐ Districts	☐ Edwards Aquifer	☐ Emissions Inventory Air	☐ Industrial Hazardous Waste
☐ Municipal Solid Waste	☐ New Source Review Air	☐ OSSF	☐ Petroleum Storage Tank	☐ PWS
☐ Sludge	☐ Storm Water	☐ Title V Air	☐ Tires	☐ Used Oil
☐ Voluntary Cleanup	☐ Waste Water	☐ Wastewater Agriculture	☐ Water Rights	☐ Other:

SECTION IV: Preparer Information

40. Name:	Ms. Denise Rogers	41. Title:	Environmental Compliance Manager

42. Telephone Number	43. Ext./Code	44. Fax Number	45. E-Mail Address
(832) 203-6493		( ) -	Denise-Rogers@Texasgulfterminals.com

SECTION V: Authorized Signature

46. By my signature below, I certify, to the best of my knowledge, that the information provided in this form is true and complete, and that I have signature authority to submit this form on behalf of the entity specified in Section II, Field 6 and/or as required for the updates to the ID numbers identified in field 39.

Company:	Texas Gulf Terminals Inc	Job Title:	Environmental Compliance Manager
Name*(In Print)* :	Ms. Denise Rogers	Phone:	(832) 203-6493
Signature:		Date:	

Tank Farm
NRSP Approval Documentation

Go To: Title V Federal Operating Permits

06/26/2018 ----------AirPermits IMS - PROJECT RECORD ----------

Project#: **287215** Status: **COMPLETE**
Project Administrative Name: **OGS STANDARD PERMIT FOR EXISTING REGISTRATION**
Project Technical Name: **TGTI TERMINAL**

PROJECT ACTIONS

Permit	Action Type	Permit Type	Received Date	Permit Status	Renewal Date	Action Status	Complete Date
151335	REVISION	STDPMT	06/25/2018	ISSUED	04/09/2028	COMPLETE	06/25/2018

Assigned Staff:
REVIEW ENG: STAFF , EPERMIT

Customer Name: **TEXAS GULF TERMINALS INC**
Legal Name: **Texas Gulf Terminals Inc.**
CN Number : **CN605490085**

Permit Information:
REGULATED ENTITY NUMBER: RN110317666

Permit	Account	Permittee Name	County	Region	City	State	Location
151335		TGTI ONSHORE TERMINAL	NUECES	REGION 14 - CORPUS CHRISTI	CORPUS CHRISTI	TEXAS	1 MI E FROM THE INTERSECTION OF COUNTY ROAD 80 & COUNTY ROAD 43

FEE:

Permit	Action Type	Reference	Fee Receipt Number	Fee Amount Paid	Fee Refund Amount	Fee Receipt Date	Fee Payment Type
151335	REVISION	377598	582EA000307395	850.00		06/24/2018	CC

TRACKING ELEMENTS

TE Name	Start Date	Complete Date

PROJECT RULES:

Unit Desc	Rule Desc	On Application	Approve
OIL AND GAS PRODUCTION FACILITIES	6002 - NON RULE 2012-NOV-08	Y	Y

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Tank Farm
PBR 106.511 Documentation for Emergency Generator

MEMORANDUM

To: Ms. Denise Rogers, Texas Gulf Terminals Inc. TGTI Onshore Terminal
From: Mr. Brian Burdorf, Trinity Consultants
Date: June 26, 2018
RE: On-Site Permit By Rule Documentation for Emergency Generator Engine at the TGTI Onshore Terminal

Texas Gulf Terminals, Inc. is planning to construct a crude oil/condensate onshore terminal known as the Texas Gulf Terminals Inc (TGTI) Onshore Terminal on the mainland near the Laguna Madre shore line in Nueces County, Texas. Nueces County is currently classified as an attainment area for all criteria pollutants.[1] TGTI has been assigned Texas Commission on Environmental Quality (TCEQ) Customer Reference Number (No.) (CN) CN605490085 and and TGTI Onshore Terminal has been assigned TCEQ Regulated Entity No. (RN) RN110317666. The New Project Notification (NPN) has been assigned the Registration Number 151335.

TGTI is claiming Permit By Rule (PBR) authorization 30 TAC §106.511 – *Portable and Emergency Engines and Turbines* for one emergency generator engine at the proposed terminal. The following table details the emergency generator engine:

Emission Point Number	Make	Model Number	Horsepower	Location
EGEN-01	TBD	TBD	1300	Onshore Terminal

This PBR does not require registration with the TCEQ; therefore, this memo includes all necessary documentation to claim authorization under PBR §106.511. In addition, the proposed emergency generator is located in Nueces County. Furthermore, this memo documents that these engines meet the general and specific PBR requirements by including the following:

- Attachment 1. Emission Calculations
- Attachment 2. General PBR Requirements and 106.4 Checklist
- Attachment 3. Specific PBR Requirements

[1]The United States Environmental Protection Agency Green Book. Source: http://www.epa.gov/oaqps001/greenbk/anay_tx.html, accessed in June, 2018.

Attachment 1: Emission Calculations

Texas Gulf Terminals Inc.
TGTI Onshore Terminal
Emergency Generator Emission Rate Calculations

FIN: EGEN-01
EPN: EGEN-01
No. of Units 1

EPN	Rating of Engine for Emergency Generator [2]	Rating of Engine for Emergency Generator [2]	Annual Operation [1]	Fuel Type[1]	Heating Value
	(HP)	(MMBtu/hr)	(hrs)		(Btu/scf)
EGEN-01	1300	44	100	Natural Gas	1,020

[1] Based on information provided by Lloyd Engineering, Inc. to TGTI/ Trinity Consultants on June 12 2018.

[2] Rating data is assumed.

EPN	Criteria Pollutant Emission Factors					
	NOx[3]	CO[3]	VOC[3]	SO_2 [4]	PM/ PM_{10}/ $PM_{2.5}$[4]	Benzene[4]
	(g/HP-hr)	(g/HP-hr)	(g/HP-hr)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)
EGEN-01	2.40	4.00	1.00	0.00059	0.0194	1.58E-03

EPN	Criteria Pollutant Hourly Emissions					
	NOx lb/hr	CO lb/hr	VOC lb/hr	SO_2 lb/hr	PM/ PM_{10}/ $PM_{2.5}$ lb/hr	Benzene lb/hr
EGEN-01	6.88	11.46	2.87	0.03	0.84	6.87E-02

EPN	Criteria Pollutant Annual Emissions					
	NOx tpy	CO tpy	VOC tpy	SO_2 tpy	PM/ PM_{10}/ $PM_{2.5}$ tpy	Benzene tpy
EGEN-01	0.34	0.57	0.14	0.00	0.042	3.44E-03

[3] VOC, NOx, and CO Emission Factors are data obtained from Table 1 of 40 CFR 60 NSPS JJJJ for Natural Gas fired Stationary Emergency engines greater than 25 hp.

[4] SO_2, PM, and Benzene emission factors are obtained from AP-42 Section 3.2, Natural Gas Fired Reciprocating Engines, July 2000

Sample Calculation:

Hourly Emissions (lb/hr) = Emission Factor (lb/MMscf) x Heating Value (Btu/scf) / Engine Rating of Emergency Generator (MMBtu/hr)

Annual Emissions (tpy) = Hourly Emissions (lb/hr) x Annual Operating Hours (hrs/yr) / 2,000 (lb/ton)

Attachment 2: General PBR Requirements

Requirements for Permitting by Rule
(30 TAC §106.4)
Effective April 17, 2014

Pursuant to the Texas Health and Safety Code, Texas Clean Air Act (TCAA), §382.057, the facilities or types of facilities listed in 30 TAC Chapter 106 are exempt from the permitting requirements of the TCAA, §382.0518 because such facilities will not make a significant contribution of air contaminants to the atmosphere. A facility shall meet the following conditions to be exempt from TCAA, §382.0518.

(a) To qualify for a permit by rule, the following general requirements must be met.

(1) Total actual emissions authorized under permit by rule from the facility shall not exceed the following limits, as applicable:

(A) 250 tons per year (tpy) of carbon monoxide (CO) or nitrogen oxides (NO_X);

(B) 25 tpy of volatile organic compounds (VOC), sulfur dioxide (SO_2), or inhalable particulate matter (PM);

(C) 15 tpy of particulate matter with diameters of 10 microns or less (PM_{10});

(D) 10 tpy of particulate matter with diameters of 2.5 microns or less ($PM_{2.5}$); or

(E) 25 tpy of any other air contaminant except:

(i) water, nitrogen, ethane, hydrogen, and oxygen; and

(ii) notwithstanding any provision in any specific permit by rule to the contrary, greenhouse gases as defined in §101.1 of this title (relating to Definitions).

As presented in Attachment 1 of this memo, the total emissions from the emergency generator will not exceed 250 tpy of CO or NO_X; 25 tpy of VOC or SO_2 or PM; 15 tpy of PM_{10} or 10 tpy of $PM_{2.5}$; or 25 tpy of any other air contaminant except carbon dioxide, water, nitrogen, methane, ethane, hydrogen, oxygen, and GHGs.

(2) Any facility or group of facilities, which constitutes a new major stationary source, as defined in §116.12 of this title (relating to Nonattainment and Prevention of Significant Deterioration Review Definitions), or any modification which constitutes a major modification, as defined in §116.12 of this title, under the new source review requirements of the Federal Clean Air Act (FCAA), Part D (Nonattainment) as amended by the FCAA Amendments of 1990, and regulations promulgated thereunder, must meet the permitting requirements of Chapter 116, Subchapter B of this title (relating to New Source Review Permits) and cannot qualify for a permit by rule under this chapter. Persons claiming a permit by rule under this chapter should see the requirements of §116.150 of this title (relating to New Major Source or Major Modification in Ozone Nonattainment Areas) to ensure that any applicable netting requirements have been satisfied.

Nueces County is currently classified as an attainment area for all criteria pollutants. Therefore, this requirement does not apply.

(3) *Any facility or group of facilities, which constitutes a new major stationary source, as defined in 40 Code of Federal Regulations (CFR) §52.21, or any change which constitutes a major modification, as defined in 40 CFR §52.21, under the new source review requirements of the FCAA, Part C (Prevention of Significant Deterioration) as amended by the FCAA Amendments of 1990, and regulations promulgated thereunder because of emissions of air contaminants other than greenhouse gases, must meet the permitting requirements of Chapter 116, Subchapter B of this title and cannot qualify for a permit by rule under this chapter. Notwithstanding any provision in any specific permit by rule to the contrary, a new major stationary source or major modification which is subject to Chapter 116, Subchapter B, Division 6 of this title due solely to emissions of greenhouse gases may use a permit by rule under this chapter for air contaminants that are not greenhouse gases. However, facilities or projects which require a prevention of significant deterioration permit due to emissions of greenhouse gases may not commence construction or operation until the prevention of significant deterioration permit is issued.*

The TGTI Onshore Terminal is a minor source with respect to PSD review for criteria pollutants and GHGsThe affected facilities under this PBR registration do not constitute a new major stationary source or a major modification; therefore, PSD review is not triggered.

(4) *Unless at least one facility at an account has been subject to public notification and comment as required in Chapter 116, Subchapter B or Subchapter D of this title (relating to New Source Review Permits or Permit Renewals), total actual emissions from all facilities permitted by rule at an account shall not exceed 250 tpy of CO or NO_X; or 25 tpy of VOC or SO_2 or PM; or 15 tpy of PM_{10}; or 10 tpy of $PM_{2.5}$; or 25 tpy of any other air contaminant except carbon dioxide, water, nitrogen, methane, ethane, hydrogen, and oxygen, and GHGs (as specified in §106.2 of this title (relating to Applicability)).*

Since the TGTI Onshore Terminal has not been subject to public notice, emissions from all PBRs must be compared to the limits noted above. Emissions from MSS activities and the emergency engines will not exceed 250 tpy of CO or NO_X; 25 tpy of VOC or SO_2 or PM; 15 tpy of PM_{10} or 10 tpy of $PM_{2.5}$; or 25 tpy of any other air contaminant except carbon dioxide, water, nitrogen, methane, ethane, hydrogen, oxygen, and GHGs.

(5) *Construction or modification of a facility commenced on or after the effective date of a revision of this section or the effective date of a revision to a specific permit by rule in this chapter must meet the revised requirements to qualify for a permit by rule.*

The TGTI Onshore Terminal meets the requirements under the PBR currently in effect. In the event that the facilities are modified, the TGTI Onshore Terminal will re-evaluate the applicability of the PBRs in effect at the time of modification.

(6) *A facility shall comply with all applicable provisions of the FCAA, §111 (Federal New Source Performance Standards) and §112 (Hazardous Air Pollutants), and the new source review requirements of the FCAA, Part C and Part D and regulations promulgated thereunder.*

The emergency generator engine is potentially subject to New Source Performance Standards (NSPS) under 40 CFR 60, Subpart JJJJ. The engine was manufactured after January 1, 2009, and therefore, is subject to NSPS Subpart JJJJ. The TGTI Onshore Terminal will comply with the applicable requirements of this subpart for this engine.

The emergency generator engine is potentially subject to Maximum Achievable Control Technology (MACT) under 40 CFR 63, Subpart ZZZZ. The engine manufactured after April 1, 2006, EPN EGEN-01, complies with 40 CFR 63, Subpart ZZZZ by complying with 40 CFR 60, Subpart JJJJ. The TGTI Onshore Terminal will comply with the applicable requirements of this subpart for this engine.

(7) There are no permits under the same commission account number that contain a condition or conditions precluding the use of a permit by rule under this chapter.

The TGTI Onshore Terminal has no TCEQ permits that preclude the use of a PBR under this chapter.

(8) The proposed facility or group of facilities shall obtain allowances for NO_X if they are subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program).

The requirements of 30 TAC Chapter 101, Subchapter H, Division 3 of this title applies to facilities located in the Houston/Galveston nonattainment area. The TGTI Onshore Terminal is located in Nueces County, Texas; therefore, 30 TAC Chapter 101, Subchapter H, Division 3 does not apply to the TGTI Onshore Terminal.

(b) No person shall circumvent by artificial limitations the requirements of §116.110 of this title (relating to Applicability).

The TGTI Onshore Terminal will meet all the requirements of 30 TAC Chapter 106. Therefore, a state permit is not required, and the requirements of 30 TAC §116.110 will not be circumvented.

(c) The emissions from the facility shall comply with all rules and regulations of the commission and with the intent of the Texas Clean Air Act (TCAA), including protection of health and property of the public, and all emissions control equipment shall be maintained in good condition and operated properly during operation of the facility.

The TGTI Onshore Terminal will be in compliance with the rules and regulations of the TCAA. In addition, compliance with the requirements of 30 TAC Chapter 106 ensures protection of health and property of the public.

(d) Facilities permitted by rule under this chapter are not exempted from any permits or registrations required by local air pollution control agencies. Any such requirements must be in accordance with TCAA, §382.113 and any other applicable law.

The TGTI Onshore Terminal Facility is located within Nueces County, which does not have a local air pollution control program.

Recordkeeping

(30 TAC §106.8)

Effective November 1, 2001

(a) Owners or operators of facilities and sources that are de minimis as designated in §116.119 of this title (relating to De Minimis Facilities or Sources) are not subject to this section.

The proposed project included in this application does not include de minimis facilities. Therefore, the proposed project is subject to the recordkeeping requirements in §106.8.

(b) Owners or operators of facilities operating under a permit by rule (PBR) in Subchapter C of this chapter (relating to Domestic and Comfort Heating and Cooling) or under those PBRs that only name the type of facility and impose no other conditions in the PBR itself do not need to comply with specific recordkeeping requirements of subsection (c) of this section. A list of these PBRs will be available through the commission's Austin central office, regional offices, and the commission's website. Upon request from the commission or any air pollution control program having jurisdiction, claimants must provide information that would demonstrate compliance with §106.4 of this title (relating to Requirements for Permitting by Rule), or the general requirements, if any, in effect at the time of the claim, and the PBR under which the facility is authorized.

The emergency generator is not exempt from the recordkeeping requirements of subsection (c) of this section and will comply with the applicable requirements in this section.

(c) Owners or operators of all other facilities authorized to be constructed and operate under a PBR must retain records as follows:

(1) maintain a copy of each PBR and the applicable general conditions of §106.4 of this title or the general requirements, if any, in effect at the time of the claim under which the facility is operating. The PBR and general requirements claimed should be the version in effect at the time of construction or installation or changes to an existing facility, whichever is most recent. The PBR holder may elect to comply with a more recent version of the applicable PBR and general requirements;

TGTI will maintain a copy of each PBR and the applicable general conditions of PBR §106.4(Attachment 4), as required by this provision. The PBR and general requirements claimed are the most recent versions as of the date of this document.

(2) maintain records containing sufficient information to demonstrate compliance with the following: all applicable general requirements of §106.4 of this title or the general requirements, if any, in effect at the time of the claim and all applicable PBR conditions;

TGTI will maintain records containing sufficient information to demonstrate compliance with the general requirements of PBR §106.4 and specific PBR requirements for each PBR that is claimed.

(3) keep all required records at the facility site. If however, the facility normally operates unattended, records must be maintained at an office within Texas having day-to-day operational control of the plant site;

TGTI will maintain all records needed to demonstrate compliance with this section at the TGTI Onshore Terminal.

(4) make the records available in a reviewable format at the request of personnel from the commission or any air pollution control program having jurisdiction;

TGTI will maintain records in a reviewable format and can make them available to the TCEQ or any other air pollution control program having jurisdiction upon request.

(5) beginning April 1, 2002, keep records to support a compliance demonstration for any consecutive 12-month period. Unless specifically required by a PBR, records regarding the quantity of air contaminants emitted by a facility to demonstrate compliance with §106.4 of this title prior to April 1, 2002 are not required under this section; and

TGTI will maintain records for any consecutive 12-month period to support a compliance demonstration with the general requirements and the specific PBRs claimed.

(6) for facilities located at sites designated as major in accordance with §122.10(13) of this title (relating to General Definitions) or subject to or potentially subject to any applicable federal requirement, retain all records demonstrating compliance for at least five years. For facilities located at all other sites, all records demonstrating compliance must be retained for at least two years. These record retention requirements supersede any retention conditions of an individual PBR.

TGTI will maintain records for a period of at least five years, as required.

Attachment 3: Specific PBR Requirements

Requirements for Portable and Emergency Engines and Turbines
(30 TAC §106.511)
Effective September 4, 2000

Internal combustion engine and gas turbine driven compressors, electric generator sets, and water pumps, used for portable, emergency, and/or standby services are permitted by rule, provided that the maximum annual operating hours shall not exceed 10% of the normal annual operating schedule of the primary equipment; and all electric motors. For purposes of this section, "standby" means to be used as a "substitute for" and not "in addition to" other equipment.

The emergency generator engine at the TGTI Onshore Terminal operates less than 876 hours annually. Therefore, the emergency engine complies with this rule.

Booster Station
NRSP Application

TEXAS GULF TERMINALS INC.
5 HOUSTON CENTER, 1401 MCKINNEY, SUITE 1500, HOUSTON, TX 77010, USA TEL: +(1) 832 203 6400 - FAX: +(1) 832 203 6401

June 26, 2018

Air Permits Initial Review Team (APIRT)
Texas Commission on Environmental Quality
Building C, Third Floor, Room 300 W, Mail Code 161
12100 Park 35 Circle
Austin, TX 78753

RE: ***Air Quality Standard Permit for Oil and Gas Handling and Production Facilities***
Texas Gulf Terminals Inc. – TGTI Booster Station – Kleberg County
Registration No. 152441
TCEQ Customer Reference No. (CN) CN605490085

To Whom It May Concern,

Texas Gulf Terminals, Inc. (TGTI) submitted a Non-Rule Standard Permit (NRSP) registration in April 2018 to authorize the construction of a crude oil/condensate terminal known as the TGTI Onshore Terminal on the mainland near the Laguna Madre shore line in Nueces County, Texas. The NRSP registration was approved on April 9, 2018 with the assigned Registration No. 151335. With this submittal, TGTI is proposing to construct a booster station approximately 5 miles away from the TGTI Terminal (TGTI Booster Station) and authorize the following emission sources:

- One (1) new 300-barrel horizontal tank (EPN D-TK) to store liquids resulting from pigging and pump manifold clearing operations; and
- Fugitive components (EPN FUG)

Please note that TGTI submitted the pre-construction notification (Notification Number 244901, Permit No. 152441) for this project on June 22, 2018 via STEERS. The $900 application fee [$850 NRSP fee and $50 New Project Notification (NPN) fee] has been submitted electronically through the TCEQ STEERS system.

Additionally, TGTI is requesting TCEQ to issue a new Regulated Entity (RN) number for the TGTI Booster Station (Permit 152441) distinct from the TGTI Onshore Terminal (Permit 151335). A Core Data Form is provided in Appendix D of this submittal.

If you have any questions or comments regarding this submittal, please do not hesitate to contact me directly at 832-203-6493.

Sincerely,

Denise Rogers

Denise Rogers
Environmental Compliance Manager

Enclosure

cc: TCEQ Region 14, Corpus Christi
Mr. Brian Burdorf, Trinity Consultants, Inc.

TCEQ NON-RULE STANDARD PERMIT REGISTRATION

Texas Gulf Terminals Inc.
TGTI Booster Station
Kleberg County, Texas

Prepared By:

TRINITY CONSULTANTS
1800 West Loop South
Suite 1000
Houston, TX 77027
(713) 552-1371

June 2018

Project 174403.0035

Trinity Consultants

Environmental solutions delivered uncommonly well

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1. EXECUTIVE SUMMARY

Texas Gulf Terminals, Inc. (TGTI) submitted a Non-Rule Standard Permit (NRSP) registration in April 2018 to authorize the construction of a crude oil/condensate terminal known as the TGTI Onshore Terminal on the mainland near the Laguna Madre shore line in Nueces County, Texas. The NRSP registration was approved on April 9, 2018 with the assigned Registration No. 151335. TGTI has been assigned Texas Commission on Environmental Quality (TCEQ) Customer Reference Number (No.) (CN) 605490085.

With this submittal, TGTI is proposing to construct a booster station near the TGTI Terminal (TGTI Booster Station) and authorize the following emission sources at the TGTI Booster Station:

- One (1) new 300-barrel horizontal tank (EPN D-TK) to store liquids resulting from pigging and pump manifold clearing operations; and
- Fugitive components (EPN FUG)

Pigging operations will be launched from the TGTI Terminal and the pigs will return to the TGTI Terminal once pigging is completed. Therefore, the emissions from pigging operations are authorized under NRSP Registration No. 151335. Although the proposed TGTI Booster Station is located outside of the Barnett Shale Counties, TGTI is voluntarily proposing to comply with the requirements of the NRSP.

The associated permit fee has also been submitted electronically through the TCEQ STEERS system. This registration is being submitted before the required timeline of 90 days from the start of operation per Section (f)(5)(A) of the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities. This registration demonstrates that the site complies with the NRSP requirements; therefore, may be authorized to operate under the specified standard permit provisions.

Additionally, TGTI is requesting TCEQ to issue a new Regulated Entity (RN) number for the TGTI Booster Station (Permit 152441) distinct from the TGTI Onshore Terminal (Permit 151335).

This application includes the all required TCEQ forms as well as supporting emissions calculations. Moreover, Section 2 of this application contains a process description and process flow diagrams. The emission calculation methodology is addressed in Section 3 of this document, along with an emissions summary. The impacts analysis is illustrated in Section 4. Sections 5 and 6 address the Standard Permit (SP) and NRSP requirements. A Best Available Control Technology (BACT) review is provided in Section 7. State and federal applicability is described in Section 8. The Federal New Source Review (FNSR) analysis is discussed in Section 9. The capital cost of this project will be greater than $2,000,000; therefore, a Professional Engineer (P.E.) review was conducted. Section 10 contains the signature from a Texas licensed Professional Engineer, which assures that the methodologies used to develop the emission calculations and evaluate the proposed BACT in the permit application are valid and follow generally accepted engineering practices.

In addition, the following information is provided in the attached appendices of this registration:

Appendix A – TCEQ Table 1(a)
Appendix B – Detailed Emissions Calculations
Appendix C – Area Map and Plot Plan
Appendix D – Core Data Form

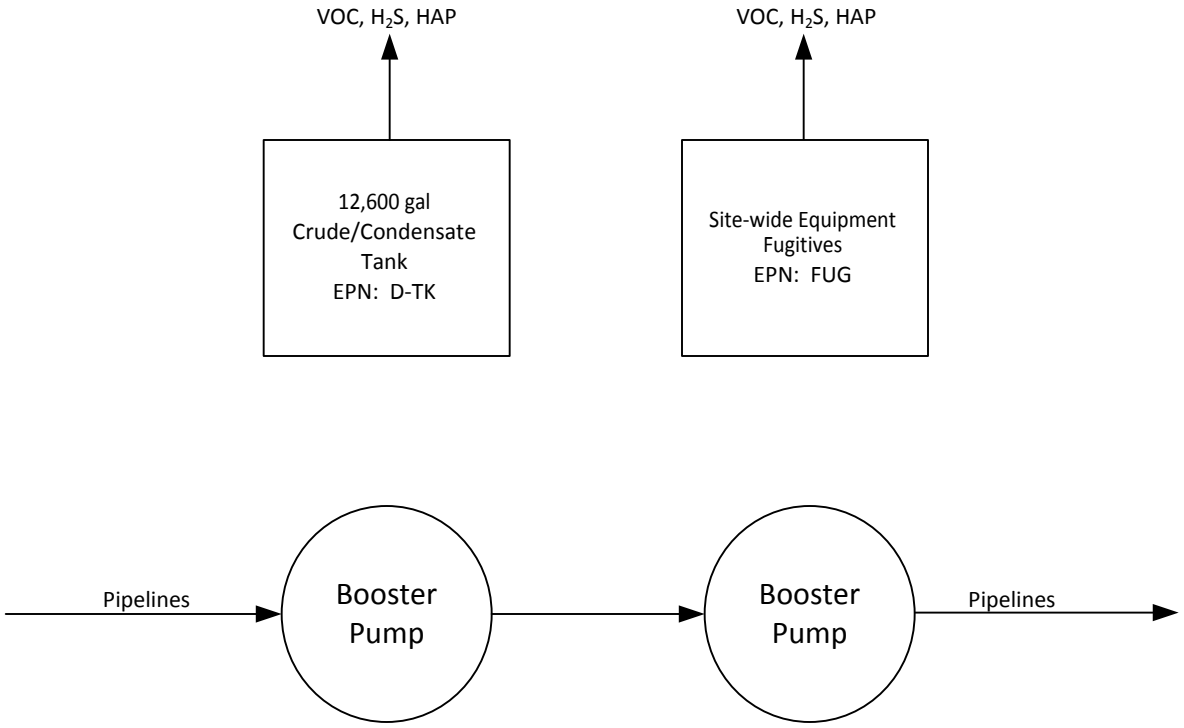
2. PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

The TGTI Booster Station will be located on the mainland near Laguna Madre and includes two booster pumping systems powered by electric motors totaling approximately 10,000 horse power per line. No local back-up power generation will be relied upon on-site. Additionally, by-passes are installed for pigging operations to clear pipelines from the TGTI Booster Station to the TGTI Terminal (authorized under NSRP Registration No. 151335). All TGTI Terminal pumps and TGTI Booster Station pumps will shut down in the event of a sudden decrease or increase in line pressure.

The pigging and pump manifold clearing operations will occur no more than four (4) times per year. During the pigging operations, the pig will be launched into one of the 30" lines from the TGTI Terminal to the TGTI Booster Station. A pump at the TGTI Terminal will push the pig to a location downstream of the TGTI Booster Station, while the booster pump manifold is being drained and cleared into a 300-barrel Day Tank (EPN D-TK) at the TGTI Booster Station. The pigging operation will continue clearing the 30" lines with the pig back into the TGTI Terminal.

The contents of the Day Tank will be loaded into tank trucks that carry the crude back to the TGTI Terminal. The loading of tank trucks will be under tank truck flow connections with vapor return lines to the Day Tank. These connections and operations will be under seal with no emissions released to the atmosphere.

A process flow diagram is included at the end of this section for reference.



Texas Gulf Terminals Inc.

Texas Gulf Terminals Inc. Booster Station
Process Flow Diagram

Trinity Consultants

June 2018

3. EMISSIONS CALCULATION METHODOLOGY

This section describes the emissions calculation methodologies used to calculate emissions from the sources at the TGTI Booster Station. The sources at the TGTI Booster Station are expected to generate emissions of volatile organic compounds (VOCs) and hazardous air pollutants (HAPs), specifically benzene. A summary of emissions proposed in this application is provided at the end of this section. Detailed emission calculations for this registration are included in Appendix B.

3.1. STORAGE TANKS

Emissions from the Day Tank include VOC, H_2S, and benzene. Table 3-1 below lists out the tank capacity and proposed throughputs of the Day Tank, as well as the material true vapor pressure.

Table 3-1. Storage Tanks Located at the TGTI Terminal

EPN	Tank Contents	Tank Size (bbl)	Maximum Filling Rate (bbl/hr)	Throughput (bbl/year)	Material Maximum True Vapor Pressure (psia)
D-TK	Crude/Condensate	300	300	1,200	11.0

TGTI conservatively estimated the maximum and average Total Vapor Pressure (TVP) of the tank content to be 11 psia. The hourly and annual benzene emissions are conservatively based on 0.95% benzene in crude oil/condensate. The hourly and annual H_2S emissions are based on H_2S vapor fraction of 24 ppmv.

The short-term emissions were calculated in accordance with the TCEQ Guidance Document on *Estimating Short Term Emission Rates from Tanks* (APDG 6250v1, Revised February 2018) as outlined below.

$$L_{MAX} = \frac{M_V \times P_{VA}}{R \times T} \times FR_M$$

Where:

L_{MAX}	=	Maximum short term emission rate, lbs/hour
M_V	=	Vapor molecular weight, lb/lb-mole
P_{VA}	=	Vapor pressure at worst case temperature, psia
FR_M	=	Maximum filling rate, gal/hr
R	=	Ideal gas constant, 80.273 (psia x gal)/(lbmol x °R)
T	=	Worst case liquid surface temperature, 95°F or the actual temperature, whichever is higher

The annual emissions were calculated in accordance with U.S. EPA AP-42 Section 7.1.3.1 (November 2006). A summary of the emissions from the Day Tank are provided in the table below, with detailed emissions calculation presented in Appendix B of this registration.

Table 3-2. Summary of Tank Emissions at the TGTI Terminal

EPN	Description	Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
D-TK	Day Tank	VOC	141.97	2.99
		H_2S	< 0.01	< 0.01
		Benzene	1.35	0.03

3.2. FUGITIVE EMISSIONS FROM PIPING COMPONENTS

Process fugitive emissions result from leaking components (EPN FUG) such as valves, flanges, and pumps. Emissions of process fugitives are estimated using a representative component count and the corresponding oil and gas production emission factors provided in the EPA's "Protocol for Equipment Leak Emission Estimates" document, as referenced in TCEQ's Equipment Leak Fugitives guidance document.[1,2] Based on the liquids analysis, the components are assumed to be in light oil service, and are conservatively assumed to be 100% VOC.

Emissions were calculated conservatively assuming no leak detection and repair (LDAR) program will be executed at the TGTI Booster Station. A summary of the emissions from the fugitives are provided in the in the table below:

Table 3-3. Summary of Fugitive Emissions at the TGTI Terminal

EPN	Description	Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
FUG-300	Meter Skids Fugitives	VOC	0.39	1.73
		H_2S	<0.01	<0.01
		Benzene	<0.01	0.02

[1] U.S. EPA. Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017). November 1995.

[2] TCEQ. Industrial Emissions Assessment Section, Emissions Factors for Equipment Leak Fugitive Components, RG-360A, January 2008.

4. IMPACTS EVALUATION

The NRSP requires an impacts evaluation for National Ambient Air Quality Standards (nitrogen dioxide and sulfur dioxide), State Property Line Standards (sulfur dioxide and hydrogen sulfide), and State Health Effects Review (benzene). Since this project will only result in emissions of VOC (including benzene) and hydrogen sulfide (H_2S), only State Property Line Standards for H_2S and State Health Effects Review for benzene are required.

Per the NRSP, if an off-site receptor is greater than one (1) mile from the site, no further analysis is required for a State Health Effects Evaluation. If the property line is greater than one (1) mile from the emission sources, then no further analysis is required for NAAQS or State Property Line Standards. Since the closest off-site receptor is greater than 1 mile from the site, a State Health Effects Evaluation is not required. Also, the NAAQS and State Property Line Standards will not be required since the property line is greater than one (1) mile of the emission sources.

Since the nearest off-site receptor is greater than 1 mile from the site, analysis for benzene is not required under State Health Effects Evaluation. The de minimis thresholds for impacts evaluation, as specified in the NRSP Section (k)(3)(C), are shown in Table 4-1 below. Based on the emissions calculations shown in Appendix B of this application and shown in Table 4-1 below, the emissions of H_2S are less than the specified de minimis limit; therefore, no further impacts review is required.

Table 4-1. Impacts Evaluation Required?

	Hourly H_2S	**Hourly Benzene**
	E (lb/hr)	**E (lb/hr)**
Current Site-wide Total	3.35E-03	1.46
De Minimis Limits[1]	0.025	0.039
Impacts Review Required?	No	N/A[2]

[1] De minimis limits per the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, Effective November 8, 2012, (k)(3)(C).

[2] An impacts evaluation is not required for benzene as the Booster Station meets the requirements under (k)(3)(A) per the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, Effective November 8, 2012 is defined in 101.1(115) and does not include methane and ethane.

5. GENERAL STANDARD PERMIT REQUIREMENTS

According to the NRSP, Section (g), the site must comply with all applicable requirements of 30 TAC §116.610; §116.611, Registration to Use a Standard Permit; §116.614, Standard Permit Fees; and §116.615, General Conditions. The NRSP supersedes the notification requirements of 30 TAC §116.615, General Conditions and the emission limitations of 30 TAC §116.610(a)(1), Applicability.

5.1. APPLICABILITY (30 TAC §116.610) EFFECTIVE FEBRUARY 1, 2006

(a) Under the Texas Clean Air Act, §382.051, a project that meets the requirements for a standard permit listed in this subchapter or issued by the commission is hereby entitled to the standard permit, provided the following conditions listed in this section are met. For the purposes of this subchapter, project means the construction or modification of a facility or a group of facilities submitted under the same registration.

(1) Any project that results in a net increase in emissions of air contaminants from the project other than carbon dioxide, water, nitrogen, methane, ethane, hydrogen, oxygen, or those for which a national ambient air quality standard has been established must meet the emission limitations of §106.261 of this title (relating to Facilities (Emission Limitations), unless otherwise specified by a particular standard permit.

The NRSP supersedes the emission limitations of this citation per Section (g). As such, this analysis is not required.

(2) Construction or operation of the project must be commenced prior to the effective date of a revision to this subchapter under which the project would no longer meet the requirements for a standard permit.

The project will meet the requirements of the current version of the NRSP at the time construction and operation commences.

(3) The proposed project must comply with the applicable provisions of the Federal Clean Air Act (FCAA), §111 (concerning New Source Performance Standards) as listed under 40 Code of Federal Regulations (CFR) Part 60, promulgated by the United States Environmental Protection Agency (EPA).

There are no New Source Performance Standards (NSPS) standards in 40 CFR Part 60 applicable to the sources included in this registration.

(4) The proposed project must comply with the applicable provisions of FCAA, §112 (concerning Hazardous Air Pollutants) as listed under 40 CFR Part 61, promulgated by the EPA.

There are no National Emission Standards for Hazardous Air Pollutants (NESHAP) standards in 40 CFR Part 61 applicable to the sources included in this registration.

(5) The proposed project must comply with the applicable maximum achievable control technology standards as listed under 40 CFR Part 63, promulgated by the EPA under FCAA, §112 or as listed under Chapter 113, Subchapter C of this title (relating to National Emissions Standards for Hazardous Air Pollutants for Source Categories (FCAA, §112, 40 CFR Part 63)).

There are no National Emission Standards for Hazardous Air Pollutants (NESHAP) standards in 40 CFR Part 63 applicable to the sources included in this registration.

(6) *If subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) the proposed facility, group of facilities, or account must obtain allocations to operate.*

The TGTI Booster Station will be located in Kleberg County, which is not part of the Houston-Galveston-Brazoria ozone nonattainment area; therefore, the Mass Emissions Cap and Trade program requirements do not apply.

(b) *Any project that constitutes a new major stationary source or major modification as defined in §116.12 of this title (relating to Nonattainment and Prevention of Significant Deterioration Review Definitions) is subject to the requirements of §116.110 of this title (relating to Applicability) rather than this subchapter.*

The TGTI Booster Station will be located in Kleberg County, which is considered attainment or unclassified for all criteria pollutants; therefore, NNSR permitting requirements do not apply. The project does not constitute a new major stationary source under the PSD program; therefore, PSD permitting requirements do not apply and the NRSP can be claimed.

(c) *Persons may not circumvent by artificial limitations the requirements of §116.110 of this title.*

This registration is submitted to demonstrate compliance with the Standard Permit regulations. TGTI is not circumventing the requirements of 116.110 through the use of artificial limitations.

(d) *Any project involving a proposed affected source (as defined in §116.15(1) of this title (relating to Section 112(g) Definitions)) shall comply with all applicable requirements under Subchapter E of this chapter (relating to Hazardous Air Pollutants: Regulations Governing Constructed or Reconstructed Major Sources (FCAA, §112(g), 40 CFR Part 63)). Affected sources subject to Subchapter E of this chapter may use a standard permit under this subchapter only if the terms and conditions of the specific standard permit meet the requirements of Subchapter E of this chapter.*

The project does not involve an affected source as defined in 30 TAC §116.15(1). Therefore, this paragraph does not apply.

5.2. REGISTRATION TO USE A STANDARD PERMIT (30 TAC §116.611) EFFECTIVE DECEMBER 11, 2002

(a) *If required, registration to use a standard permit shall be sent by certified mail, return receipt requested, or hand delivered to the executive director, the appropriate commission regional office, and any local air pollution program with jurisdiction, before a standard permit can be used. The registration must be submitted on the required form and must document compliance with the requirements of this section, including, but not limited to:*

(1) *the basis of emission estimates;*

(2) *quantification of all emission increases and decreases associated with the project being registered;*

(3) sufficient information as may be necessary to demonstrate that the project will comply with §116.610(b) of this title (relating to Applicability);
(4) information that describes efforts to be taken to minimize any collateral emissions increases that will result from the project;
(5) a description of the project and related process; and
(6) a description of any equipment being installed.

This registration for the TGTI Booster Station includes all required items and are being submitted to TCEQ.

(b) Construction may begin any time after receipt of written notification from the executive director that there are no objections or 45 days after receipt by the executive director of the registration, whichever occurs first, except where a different time period is specified for a particular standard permit.

The NRSP specifies that construction may begin any time after receipt of a pre-construction notification. TGTI submitted a pre-construction notification to the TCEQ via STEERS. The notification was assigned Registration Number 152441.

(c) In order to avoid applicability of Chapter 122 of this title (relating to Federal Operating Permits), a certified registration shall be submitted. The certified registration must state the maximum allowable emission rates and must include documentation of the basis of emission estimates and a written statement by the registrant certifying that the maximum emission rates listed on the registration reflect the reasonably anticipated maximums for operation of the facility. The certified registration shall be amended if the basis of the emission estimates changes or the maximum emission rates listed on the registration no longer reflect the reasonably anticipated maximums for operation of the facility. The certified registration shall be submitted to the executive director; to the appropriate commission regional office; and to all local air pollution control agencies having jurisdiction over the site. Certified registrations must also be maintained in accordance with the requirements of §116.115 of this title (relating to General and Special Conditions).

(1) Certified registrations established prior to the effective date of this rule shall be submitted on or before February 3, 2003.
(2) Certified registrations established on or after the effective date of this rule shall be submitted no later than the date of operation.

The TGTI Booster Station will be a minor source under Chapter 122 requirements, relating to Title V permitting. The NRSP registration is inherently considered to be federally enforceable. As such, this registration serves as the certified registration demonstrating that emissions are below the Title V thresholds.

5.3. STANDARD PERMIT FEES (30 TAC §116.614) EFFECTIVE OCTOBER 20, 2002

Any person who registers to use a standard permit or an amended standard permit, or to renew a registration to use a standard permit shall remit, at the time of registration, a flat fee of $900 for each standard permit being registered, unless otherwise specified in a particular standard permit. No fee is required if a registration is automatically renewed by the commission. All standard permit fees will be remitted in the form of a check, certified check, electronic funds transfer, or money order made payable to the Texas Commission on Environmental Quality

(TCEQ) and delivered with the permit registration to the TCEQ, P.O. Box 13088, MC 214, Austin, Texas 78711-3087. No fees will be refunded.

TGTI has paid the $50 pre-construction notification fee and $850 registration fee, as required in the NRSP through STEERS.[3]

5.4. GENERAL CONDITIONS (30 TAC §116.615) EFFECTIVE MARCH 15, 2007

The following general conditions are applicable to holders of standard permits, but will not necessarily be specifically stated within the standard permit document.

(1) Protection of public health and welfare. The emissions from the facility, including dockside vessel emissions, must comply with all applicable rules and regulations of the commission adopted under Texas Health and Safety Code, Chapter 382, and with the intent of the Texas Clean Air Act (TCAA), including protection of health and property of the public.

This standard permit registration documents that the proposed project will comply with the rules and regulations of the TCEQ and the intent of the Texas Clean Air Act (TCAA), including protection of health and property of the public.

(2) Standard permit representations. All representations with regard to construction plans, operating procedures, and maximum emission rates in any registration for a standard permit become conditions upon which the facility or changes thereto, must be constructed and operated. It is unlawful for any person to vary from such representations if the change will affect that person's right to claim a standard permit under this section. Any change in condition such that a person is no longer eligible to claim a standard permit under this section requires proper authorization under §116.110 of this title (relating to Applicability). If the facility remains eligible for a standard permit, the owner or operator of the facility shall notify the executive director of any change in conditions which will result in a change in the method of control of emissions, a change in the character of the emissions, or an increase in the discharge of the various emissions as compared to the representations in the original registration or any previous notification of a change in representations. Notice of changes in representations must be received by the executive director no later than 30 days after the change.

TGTI understands that standard permit representations become conditions upon which the facility must be operated. Any changes to the representations in this registration will be communicated to the TCEQ, as required in 30 TAC §116.615(2).

(3) Standard permit in lieu of permit amendment. All changes authorized by standard permit to a facility previously permitted under §116.110 of this title shall be administratively incorporated into that facility's permit at such time as the permit is amended or renewed.

TGTI Booster Station will not operate under a TAC Chapter 116 case-by-case permit; therefore, this citation does not apply.

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[3] Per Non-Rule Standard Permit, Section 6002(f)(5)(C).

(4) Construction progress. Start of construction, construction interruptions exceeding 45 days, and completion of construction shall be reported to the appropriate regional office not later than 15 working days after occurrence of the event, except where a different time period is specified for a particular standard permit.

The requirements in the NRSP supersede these notification requirements per Section (g).

(5) Start-up notification.

(a) The appropriate air program regional office of the commission and any other air pollution control agency having jurisdiction shall be notified prior to the commencement of operations of the facilities authorized by a standard permit in such a manner that a representative of the executive director may be present.

(b) For phased construction, which may involve a series of units commencing operations at different times, the owner or operator of the facility shall provide separate notification for the commencement of operations for each unit.

(c) Prior to beginning operations of the facilities authorized by the permit, the permit holder shall identify to the Office of Permitting, Remediation, and Registration, the source or sources of allowances to be utilized for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program).

(d) A particular standard permit may modify start-up notification requirements.

The requirements in the NRSP supersede these notification requirements per Section (g).

(6) Sampling requirements. If sampling of stacks or process vents is required, the standard permit holder shall contact the commission's appropriate regional office and any other air pollution control agency having jurisdiction prior to sampling to obtain the proper data forms and procedures. All sampling and testing procedures must be approved by the executive director and coordinated with the regional representatives of the commission. The standard permit holder is also responsible for providing sampling facilities and conducting the sampling operations or contracting with an independent sampling consultant.

If stack sampling is required by the Executive Director, TGTI will comply with these stack sampling requirements.

(7) Equivalency of methods. The standard permit holder shall demonstrate or otherwise justify the equivalency of emission control methods, sampling or other emission testing methods, and monitoring methods proposed as alternatives to methods indicated in the conditions of the standard permit. Alternative methods must be applied for in writing and must be reviewed and approved by the executive director prior to their use in fulfilling any requirements of the standard permit.

TGTI is not requesting any alternatives to emissions control methods, sampling or other emission testing methods, or monitoring methods proposed as alternative methods in the conditions of the Standard Permit. TGTI Booster Station understands that if changes are proposed, a demonstration of equivalency of methods will be required.

(8) Recordkeeping. A copy of the standard permit along with information and data sufficient to demonstrate applicability of and compliance with the standard permit shall be maintained in a file at the plant site and

made available at the request of representatives of the executive director, the United States Environmental Protection Agency, or any air pollution control agency having jurisdiction. For facilities that normally operate unattended, this information shall be maintained at the nearest staffed location within Texas specified by the standard permit holder in the standard permit registration. This information must include, but is not limited to, production records and operating hours. Additional recordkeeping requirements may be specified in the conditions of the standard permit. Information and data sufficient to demonstrate applicability of and compliance with the standard permit must be retained for at least two years following the date that the information or data is obtained. The copy of the standard permit must be maintained as a permanent record.

TGTI will maintain records, as required by the Standard Permit, and make them available to regulatory personnel upon request.

(9) Maintenance of emission control. The facilities covered by the standard permit may not be operated unless all air pollution emission capture and abatement equipment is maintained in good working order and operating properly during normal facility operations. Notification for emissions events and scheduled maintenance shall be made in accordance with §101.201 and §101.211 of this title (relating to Emissions Event Reporting and Recordkeeping Requirements; and Scheduled Maintenance, Startup, and Shutdown Reporting and Recordkeeping Requirements).

TGTI will maintain the air pollution capture and abatement equipment for the facilities covered by this Standard Permit in good working order and will operate the air pollution capture and abatement equipment properly during normal facility operations. Notifications under 30 TAC §101.201 and §101.211 will be made, as necessary.

(10) Compliance with rules. Registration of a standard permit by a standard permit applicant constitutes an acknowledgment and agreement that the holder will comply with all rules, regulations, and orders of the commission issued in conformity with the TCAA and the conditions precedent to the claiming of the standard permit. If more than one state or federal rule or regulation or permit condition are applicable, the most stringent limit or condition shall govern. Acceptance includes consent to the entrance of commission employees and designated representatives of any air pollution control agency having jurisdiction into the permitted premises at reasonable times to investigate conditions relating to the emission or concentration of air contaminants, including compliance with the standard permit.

TGTI will comply with all applicable rules, regulations, and orders of the TCEQ and U.S. EPA, as appropriate. Regulatory personnel will be allowed to enter the site at reasonable times, as necessary.

(11) Distance limitations, setbacks, and buffer zones. Notwithstanding any requirement in any standard permit, if a standard permit for a facility requires a distance, setback, or buffer from other property or structures as a condition of the permit, the determination of whether the distance, setback, or buffer is satisfied shall be made on the basis of conditions existing at the earlier of:

(a) the date new construction, expansion, or modification of a facility begins; or

(b) the date any application or notice of intent is first filed with the commission to obtain approval for the construction or operation of the facility.

Any distance limitations, setbacks, and buffer zones will be determined as required by this section.

6. SPECIFIC STANDARD PERMIT REQUIREMENTS

According to the NRSP (6002-Non-Rule, effective November 8, 2012), the following specific requirements apply.

6.1. AIR QUALITY STANDARD PERMIT FOR OIL AND GAS HANDLING AND PRODUCTION FACILITIES EFFECTIVE NOVEMBER 8, 2012

(a) Applicability. This standard permit applies to all stationary facilities, or groups of facilities, at a site which handle gases and liquids associated with the production, conditioning, processing, and pipeline transfer of fluids or gases found in geologic formations on or beneath the earth's surface including, but not limited to, crude oil, natural gas, condensate, and produced water with the following conditions.

(1) The requirements in paragraphs (a)-(k) of this standard permit are applicable in only for new projects and dependent facilities located in the Barnett Shale (Cooke, Dallas, Denton, Ellis, Erath, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Somervell, Tarrant, and Wise Counties) on or after April 1, 2011. For all other new projects and dependent facilities in all other counties of the state, paragraph (l) of this standard permit is applicable.

The TGTI Booster Station will be located in Kleberg County, which is not defined as a Barnett Shale County; therefore, TGTI is voluntarily registering this facility under the NRSP.

(2) Only one Air Quality Standard Permit for Oil and Gas Handling and Production Facilities for an oil and gas site (OGS) may be registered for a combination of dependent facilities and authorizes all facilities in sweet or sour service. This standard permit may not be used if operationally dependent facilities are authorized by the permit by rule in Title 30, Texas Administrative Code (30 TAC) §106.352, Oil and Gas Handling and Production Facilities, or a permit under 30 TAC §116.111,General Application. Existing authorized facilities, or groups of facilities, at an OGS under this standard permit which are not changing certified character or quantity of emissions must only meet subsections (i) and (k) of this standard permit (protectiveness review and planned maintenance, startup, and shutdown (MSS) requirements) and otherwise retain their existing authorization. Other facilities which are not covered under this standard permit may be authorized by other authorizations at an OGS if (b)(6) and (k) of this standard permit are met.

The TGTI Booster Station will be authorized under only one Standard Permit. There are no operationally dependent facilities authorized under a 116.111 case-by-case construction permit.

(3) This standard permit does not relieve the owner or operator from complying with any other applicable provision of the Texas Health and Safety Code, Texas Water Code, rules of the Texas Commission on Environmental Quality (TCEQ), or any additional local, state or federal regulations. Emissions that exceed the limits in this standard permit are not authorized and are violations.

TGTI will comply with all other applicable provisions of the Texas Health and Safety Code, Texas Water Code, TCEQ rules, and any additional local, state, or federal regulations. TGTI understands that emissions that exceed the limits set forth in the Standard Permit are not authorized and are considered violations.

(4) Emissions from upsets, emergencies, or malfunctions are not authorized by this standard permit. This standard permit does not regulate methane, ethane, or carbon dioxide.

No emissions from upsets, emergencies, or malfunctions are included in this authorization.

(b) Definitions and Scope.

(1) Facility is a discrete or identifiable structure, device, item, equipment, or enclosure that constitutes or contains a stationary source. Stationary sources associated with a mine, quarry, or well test lasting less than 72 hours are not considered facilities.

(2) Receptor includes any building which is in use as a single or multi-family residence, school, day-care, hospital, business, or place of worship at the time this standard permit is registered. A residence is a structure primarily used as a permanent dwelling. A business is a structure that is occupied for at least 8 hours a day, 5 days a week, and does not include businesses who are handling or processing materials as described in subsection (a). This term does not include structures occupied or used solely by the owner or operator of the oil and gas facility, or the mineral rights owner of the property upon which the facility is located. All measurements of distance to receptors shall be taken from the emission release point at the oil and gas facility that is nearest to the point on the building that is nearest to the oil and gas facility.

(3) An OGS is defined as all facilities which meet the following:
(A) Located on contiguous or adjacent properties;
(B) Under common control of the same person (or persons under common control); and
(C) Designated under same 2-digit standard industrial classification (SIC) codes.

(4) For purposes of determining applicability of 30 TAC Chapter 122, Federal Operating Permits, the definitions of 30 TAC §122.10, General Definitions, apply.

(5) A project under this standard permit is defined as the following and must meet all requirements of this standard permit prior to construction or implementation of changes.
(A) Any new facility or new group of operationally dependent facilities at an OGS; or
(B) Physical changes to existing authorized facilities or group of facilities at an OGS which increase the potential to emit over previously registered emission limits; or
(C) Operational changes to existing authorized facilities or group of facilities at an OGS which increase the potential to emit over previously registered emission limits.

(6) For purposes of registration under this standard permit, the following facilities shall be included:
(A) All facilities or groups of facilities at an OGS which are operationally dependent on each other;
(B) Facilities must be located within a 1/4 mile of a project emission point, vent, or fugitive component, except for those components excluded in (b)(6)(C) of this standard permit;
(C) If piping or fugitive components are the only connection between facilities and the distance between facilities exceeds 1/4 mile, then the facilities are considered separate for purposes of this registration;
(D) The boundaries of the registration become fixed at the time this standard permit is registered. No individual facility may be authorized under more than one registration;
(E) Any facility or group of facilities authorized under an existing standard permit registration which is operationally dependent on a project must be revised to incorporate the project; and
(F) A registration may include facilities which are claiming 30 TAC §116.620, Installation and/or Modification of Oil and Gas Facilities as well as projects which are claiming this standard permit. Existing authorized facilities, or group of facilities, at an OGS under this standard

permit which are not changing registered and certified character or quantity of emissions must only meet paragraphs (i) and (k) of this standard permit (the protectiveness review and planned maintenance, startup, and shutdown (MSS) requirements) until the registration is renewed after December 31, 2015, after which paragraphs (a) – (k) of this standard permit apply.

(7) For purposes of all previous claims of this standard permit (or any previous version of this standard permit) where no project is occurring:

(A) Existing authorized facilities, or group of facilities, which have not registered planned MSS activity emissions prior to the effective dates in (a)(1) of this standard permit must meet paragraph (i) of this standard permit (planned MSS) no later than January 5, 2012; or

(B) Existing authorized facilities, or group of facilities, which have registered planned MSS activity emissions and compliance with 30 TAC §116.620(a)(1) has been demonstrated prior to the effective dates in (a)(1) of this standard permit, must meet paragraph (i) of this standard permit (planned MSS) no later than the registration renewal submitted after December 31, 2015.

(8) For purposes of ensuring protection of public health and welfare and demonstrating compliance with applicable ambient air standards and effects screening levels, the impacts analysis as specified in paragraph (k) of this standard permit must be completed.

(A) All impacts analysis must be done on a contaminant-by- contaminant basis for any net project increases. If a claim under this standard permit is only for planned MSS under paragraph (i) of this standard permit, the analysis shall evaluate planned MSS scenarios only.

(B) Hourly and annual emissions shall be limited based on the most stringent of paragraphs (h) or (k) of this standard permit.

TGTI will use outlined definitions, as applicable, for compliance determinations. This registration includes the facilities outlined in the scope of the NRSP. TGTI has included the necessary representations within the registration to demonstrate compliance with the NRSP requirements.

(c) Authorized Facilities, Changes and Activities.

(1) For existing OGS which are authorized by previous versions of this standard permit:

(A) A project requires registration unless otherwise specified.

(B) The following projects do not require registration, but must comply with best management practices in paragraph (e) of this standard permit, compliance demonstrations in paragraphs (i) and (j) of this standard permit and must be incorporated into the registration at the next revision or certification:

(i) Addition of any piping, fugitive components, any other new facilities that increase registered emissions less than or equal to 1.0 tpy volatile organic compounds (VOC), 5.0 tpy nitrogen oxides (NO_X), 0.01 tpy benzene, and 0.05 tpy hydrogen sulfide (H_2S) over a rolling 12-month period;

(ii) Changes to any existing facilities that increase registered emissions less than or equal to 1.0 tpy VOC, 5.0 tpy nitrogen oxides (NO_X), 0.01 tpy benzene, and 0.05 tpy H_2S over a rolling 12-month period; or

(iii) Total increases over a rolling 60-month period that are less than or equal to 5.0 tpy VOC or NO_X, 0.05 tpy benzene, or 0.1 tpy H_2S; or

(iv) Addition of any new engine rated less than 100 horsepower (hp); or

(v) Replacement of any facility if the new facility does not increase the previous registered emissions.

(C) In lieu of registering proposed changes under this standard permit, incremental emissions increases associated with construction of new facilities or changes to existing facilities may be authorized by 30 TAC §106.261, Facilities (Emission Limitations) or §106.262, Facilities (Emissions and Distance Limitations), if the maximum worst-case emissions also meet the limitations established by paragraphs (b)(8) and (k) of this standard permit for all air contaminants with proposed increases.

The entire TGTI Booster Station is being authorized with this NRSP registration and is not authorized by previous versions of this Standard Permit; therefore, this section does not apply.

(2) All authorizations under this standard permit shall meet the following:

(A) New, changed, or replacement facilities shall not exceed the thresholds for major source or major modification as defined in 30 TAC §116.12, Nonattainment and Prevention of Significant Deterioration Review Definitions, and in Federal Clean Air Act §112(g) or §112(j);

(B) All facilities shall comply with all applicable 40 Code of Federal Regulations (CFR), Parts 60, 61, and 63 requirements for New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and Maximum Achievable Control Technology (MACT); and

(C) All facilities shall comply with all applicable requirements of 30 TAC Chapters 111, Control of Air Pollution from Visible Emissions and Particulate Matter, 112, Control of Air Pollution from Sulfur Compounds, 113, Standards of Performance for Hazardous Air Pollutants and for Designated Facilities and Pollutants, 115, Control of Air Pollution from Volatile Organic Compounds), and 117, Control of Air Pollution from Nitrogen Compounds.

The TGTI Booster Station will not be subject to the Nonattainment New Source Review (NNSR) program since Kleberg County is in attainment or unclassified county for all criteria pollutants. The TGTI Booster Station project does not constitute a major source. The facility will comply with all applicable state and federal regulations, as outlined in Section 8 of this registration.

(3) To be eligible for this standard permit an applicant:

(A) shall meet all applicable requirements as set forth in this standard permit;

(B) shall not misrepresent or fail to fully disclose all relevant facts in obtaining the permit; and

(C) shall not be indebted to the state for failure to make payment of penalties or taxes imposed by the statutes or rules within the commission's jurisdiction.

The sources included in this Standard Permit registration meet the criteria set forth in this condition. TGTI is not indebted to the state for failure to make payment of penalties or taxes imposed by the statutes or rules within the commission's jurisdiction.

(4) All facilities related to the operation of any OGS, under any version of this standard permit (or co-located at a site with an OGS standard permit), previously authorized by, and continuing to meet, the conditions of a permit by rule under 30 TAC Chapter 106, Permits by Rule (or any historical version) must:

(A) Be incorporated into this standard permit in any initial registration, revision, or renewal for this standard permit. These facilities will become authorized by this standard permit and previous authorizations will be voided.

(B) Meet all emission limits established by this standard permit and review in accordance with paragraph (b)(8) of this standard permit.

(C) Meet requirements of paragraphs (e), (i), and (j) of this standard permit for Best Management Practices and Minimum Requirements, Planned MSS, and associated Records, Sampling and Monitoring of this standard permit.

(D) Only if facilities or groups of facilities are changed in such a way as to increase the potential to emit, production processing capacity, or registered emission rate, the requirements in paragraph (e) (BACT) of this standard permit are required to be met. In all other cases, these facilities are not required to meet paragraph (e) of this standard permit.

The TGTI Booster Station will comply with all applicable emission limits and BACT requirements established by this Standard Permit.

(d) Facilities and Exclusions

(1) Only the following specific facilities and groups of facilities have been evaluated for this standard permit, along with supporting infrastructure equipment and facilities, and may be included in a registration:

(A) Fugitive components, including valves, pressure relief valves, pipe flanges and connectors, pumps, compressors, stuffing boxes, instrumentation and meters, natural gas driven pneumatic pumps, and other similar devices with seals that separate process and waste material from the atmosphere and the associated piping;

(B) Separators, including all gas, oil, and water physical separation units;

(C) Treatment and processing equipment, including heater-treaters, methanol injection, glycol dehydrators, molecular or mole sieves, amine sweeteners, H_2S scavenger chemical reaction vessels for sulfur removal, and iron sponge units;

(D) Cooling towers and associated heat exchangers;

(E) Gas recovery units, including cryogenic expansion, absorption, adsorption, heat exchangers, and refrigeration units;

(F) Combustion units, including engines, turbines, boilers, reboilers, and heaters;

(G) Storage tanks for crude oil, condensate, produced water fuels, treatment chemicals, slop and sump oils and pressure tanks with liquified petroleum gases;

(H) Surface facilities associated with underground storage of gas or liquids;

(I) Truck loading equipment;

(J) Control equipment, including vapor recovery systems, glycol and amine reboiler condensers, flares, vapor combustors, and thermal oxidizers; and

(K) Temporary facilities used for planned maintenance, and temporary control devices for planned start-ups and shutdowns.

(2) Exclusions. The following are not authorized under this standard permit:

(A) Sour water strippers or sulfur recovery units;

(B) Carbon dioxide hot carbonate processing units;

(C) Water injection facilities (these facilities may otherwise be authorized by 30 TAC §106.351, Salt Water Disposal);

(D) Liquefied petroleum gases, crude oil, or condensate transfer or loading into or from railcars, ships, or barges. These facilities may otherwise be authorized by 30 TAC §106.261, Facilities (Emission Limitations)) and §106.262, Facilities (Emissions and Distance Limitations);

(E) Incinerators for solid waste destruction;

(F) Remediation of petroleum contaminated water and soil. These facilities may otherwise be authorized by 30 TAC §106.533, Remediation; and

(G) Cooling Towers and heat exchangers with direct contact with gaseous or liquid process streams containing VOC, H_2S, halogens or halogen compounds, cyanide compounds, inorganic acids, or acid gases.

This registration includes only those sources specifically evaluated and allowed under this Standard Permit. The TGTI Booster Station will not include any facilities not authorized by the Standard Permit.

(e) Best Management Practices (BMP) and Best Available Control Technology (BACT) Requirements. For any project, and any associated emission control equipment registered under this standard permit this paragraph shall be met as applicable. These requirements are not applicable to existing, unchanging facilities until any renewal submitted after December 31, 2015.

(1) All facilities which have the potential to emit air contaminants must be maintained in good working order and operated properly during facility operations. Each operator shall establish and maintain a program to replace, repair, and/or maintain facilities to keep them in good working order. The minimum requirements of this program shall include:

(A) Compliance with manufacturer's specifications and recommended programs applicable to equipment performance and effect on emissions, or alternatively, an owner or operator developed maintenance plan for such equipment that is consistent with good air pollution control practices.

(B) Cleaning and routine inspection of all equipment; and

(C) Replacement and repair of equipment on schedules which prevent equipment failures and maintain performance.

(2) Any OGS facility shall be operated at least 50 feet from any property line or receptor (whichever is closer to the facility). This distance limitation does not apply to the following:

(A) Any fugitive components that are used for isolation and or safety purposes may be located at one-half of the width of any applicable easement;

(B) Any facility at a location for which the distance requirements were satisfied at the time this standard permit is registered (provided that the authorization was maintained) regardless of whether a receptor is subsequently built or put to use less than 50 feet from any OGS facility; or

(C) Existing facilities which are located less than 50 feet from a property line or receptor when constructed and previously authorized. If modified or replaced, the operator shall consider, to the extent that good engineering practice will permit, moving these facilities to meet the 50 foot requirement. Replacement facilities must meet all other requirements of this standard permit.

(3) Engines and turbines shall meet the emission and performance standards listed in Table 6 in paragraph (m) and the following requirements:

(A) Liquid fueled engines used for back-up power generation and periodic power needs at the OGS are authorized if the fuel has no more than 0.05% sulfur and the engine is operated less than 876 hours per rolling 12-month period.

(B) Engines and turbines used for electric generation more than 876 hours per rolling 12-month period are authorized if no reliable electric service is readily available. In all other circumstances, electric generators must meet the technical requirements of the Air Quality Standard Permit for Electric Generating Unit (EGU) (not including the EGU standard permit

registration requirements) and the emissions shall be included in the registration under this standard permit;

(C) All applicable requirements of 30 TAC Chapter 117; and

(D) All applicable requirements of 40 CFR Part 60 and 40 CFR Part 63.

(E) Compression ignition engines that are rated less than 225 kW (300 hp) and emit less than or equal to the emission tier for an equivalent sized model year 2008 non-road compression ignition engine located at 40 CFR § 89.112, Table 1 are authorized.

(4) Open-topped tanks or ponds containing VOCs or H_2S are allowed up to a PTE equal to 1 tpy of VOC and 0.1 tpy of H_2S.

(5) All process equipment and storage facilities individually must meet the requirements of BACT listed in Table 10 in paragraph (m). Any combination of process equipment and storage facilities with an uncontrolled PTE of equal to or greater than 25 tpy of VOC must also meet the requirements of Table 10, row titled "Combined Control Requirements." All of the following streams and facilities must be included for this site-wide assessment:

(A) For any gaseous vent stream with a concentration of 1% VOC must be considered for capture and control requirements;

(B) For any liquid stream with a potential to emit of equal to or greater than 1 tpy VOC for each vessel or storage facility.

(6) The following shall apply to all fugitive components associated with the project:

(A) All seals and gaskets in VOC or H_2S service shall be installed, checked, and properly maintained to prevent leaking. All components shall be physically inspected quarterly for leaks.

(B) New and replaced fugitive components and instrumentation in gas or liquid service with the uncontrolled potential to emit equal to or greater than 10 tpy VOC or 1 tpy H_2S are subject to a leak detection and repair (LDAR) program as specified in Table 9 in paragraph (m). Additional requirements are applicable where uncontrolled potential to emit equal to or greater than 25 tpy VOC or 5 tpy H_2S as specified in Table 9. Planned MSS from fugitive components must also meet the requirements of Table 9.

(C) All components found to be leaking shall be repaired. Every reasonable effort shall be made to repair a leaking component. All leaks not repaired immediately shall be tagged or noted in a log. At manned sites, leaks shall be repaired no later than 30 days after the leak is found. At unmanned sites, leaks shall be repaired no later than 60 days after the leak is found. If the repair of a component would require a unit shutdown, which would create more emissions than the repair would eliminate, the repair may be delayed until the next shutdown.

(D) Tank hatches, not designed to be completely sealed, shall remain closed (but not completely sealed in order to maintain safe design functionality) except for sampling, gauging, loading, unloading, or planned maintenance activities.

(E) To the extent that good engineering practices will permit, new and reworked valves and piping connections shall be located in a place that is reasonably accessible for leak checking during plant operation and underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

(7) Tanks and vessels must utilize a paint color that minimizes the effects of solar heating (including, but not limited to, white or aluminum). To meet this requirement the solar absorptance should be 0.43 or less, as referenced in Table 7.1-6 in Compilation of Air Pollutant Emission Factors (AP-42). Paint shall be applied according to paint producers recommended application requirements if provided and in sufficient quantity as to be considered solar resistant. Paint shall be maintained in

good condition and will not compromise tank integrity. Minimal amounts of rust may be present not to exceed 10% of the external surface area of the roof or walls of the tank and in no way may compromise tank integrity. Additionally, up to 10% of the external surface area of the roof or walls of the tank or vessel may be painted with other colors to allow for identification and/or aesthetics. For tanks and vessels purposefully darkened to create the process reaction and help condense liquids from being entrained in the vapor or are in an area whereby a local, state, federal law, ordinance, or private contract predating this standard permit's effective date establishes in writing tank and vessel colors other than white, these requirements do not apply.

(8) All emission estimation methods including but not limited to computer programs such as GRI-GLYCalc, AmineCalc, E&P Tanks, and Tanks 4.0, must be used with monitoring data generated in accordance with Table 8 in subsection (m) of this section where monitoring is required. All emission estimation methods must also be used in a way that is consistent with protocols established by the commission or promulgated in federal regulations (NSPS, NESHAPS). Where control of emissions is relied upon to meet subsection (k) of this section, control monitoring is required.

(9) Process reboilers, heaters, and furnaces that are also used for control of waste gas streams may claim 50 to 99% destruction efficiency for VOCs and H_2S depending on the design and level of monitoring applied. The 90% destruction may be claimed where the waste gas is delivered to the flame zone or combustion fire box with basic monitoring as specified in paragraph (j). Any value greater than 90% and up to 99% destruction efficiency may be claimed where enhanced monitoring and/or testing are applied as specified in paragraph (j). If the waste gas is premixed with the primary fuel gas and used as the primary fuel in the device through the primary fuel burners, 99% destruction may be claimed with basic monitoring as specified in paragraph (j). In systems where the combustion device is designed to cycle on and off to maintain the designed heating parameters, and may not fully utilize the waste gas stream, records of run time and enhanced monitoring is required to claim any run time beyond 50%.

(10) Vapor recovery Systems (VRSs) may claim up to 100% control. The control efficiency is based on whether it is a mechanical VRU (mVRU) or a liquid VRU (lVRU). The VRUs must meet the appropriate design, monitoring and record-keeping in Table 7 and Table 8 in paragraph (m).

(11) Flares used for control of emissions from production, planned MSS, emergency, or upset events may claim design destruction efficiency of 98% for VOCs and H_2S and 99% for VOCs containing no more than three carbon atoms that contain no elements other than carbon and hydrogen. All flares must be designed and operated in accordance with the following:

(A) Meet specifications for minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring found in 40 CFR §60.18;
(B) If necessary to ensure adequate combustion, sufficient gas shall be added to make the gases combustible;
(C) An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes;
(D) An automatic ignition system may be used in lieu of a continuous pilot;
(E) Flares must be lit at all times when gas streams are present;
(F) Fuel for all flares shall be sweet gas or liquid petroleum gas except where only field gas is available and it is not sweetened at the site; and
(G) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed at total of 5 minutes during any two consecutive hours. Acid gas flares which must

comply with opacity limits and records in accordance with 30 TAC §111.111(a)(4), Requirements for Specified Sources, regarding gas flares, are exempt from this visible emission limitation.

(H) Flares may be designed with steam or air assist to help reduce visible emissions from the flare but must meet the appropriate requirements in 40 CFR 60.18.

(I) At no time shall minimum heating values fall below the associated minimum heating value in 60.18

(12) Thermal oxidation and vapor combustion control devices may claim design destruction efficiency from 90 to 99.9% for VOCs and H_2S depending on the design and the level of monitoring and testing applied. A device designed for the variability of the waste gas streams it controls with basic monitoring to indicate oxidation or combustion is occurring when waste gas is directed to the device may claim 90% destruction efficiency. Devices with intermediate monitoring, designed for the variability of the waste gas streams they control, with a fire box or fire tube designed to maintain a temperature above 1,400 degrees Fahrenheit (F) for 0.5 seconds, residence time; or designed to meet the parameters of a flare with minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring as found in 40 CFR §60.18, but within a full or partial enclosure may claim a design destruction efficiency of 90 to 98%. Devices with enhanced monitoring and ports and platforms to allow stack testing may claim a 99% efficiency where the devices are designed for the variability of the waste gas streams they control, with a fire box or fire tube designed to maintain a temperature above 1,400 degrees F for 0.5 seconds, residence time. The devices that can claim 99% destruction efficiency may claim 99.9% destruction efficiency if stack testing is conducted and confirms the efficiency and the enhanced monitoring is adjusted to ensure the continued efficiency. Temperature and residence time requirements may be modified if stack testing is conducted to confirm efficiencies.

BMP and BACT requirements are addressed for the TGTI Booster Station in Section 7 of this registration.

(f) Registration, Revision, and Renewal Requirements

(1) For all previous claims of this standard permit (or any previous version of this standard permit) existing authorized facilities, or group of facilities, are not required to meet the requirements of this standard permit, with the exception of planned MSS, until a renewal under the standard permit is submitted after December 31, 2015.

The TGTI Booster Station is proposed and is not existing; therefore, this exemption does not apply to the TGTI Booster Station.

(2) If no other changes except for authorizing planned MSS occurs at an existing OGS under this standard permit, or any previous version of this standard permit, (b)(7) applies.

(A) Records demonstrating compliance with paragraph (i) must be kept;

(B) If the OGS must certify emissions to establish nonapplicability of prevention of significant deterioration (PSD), nonattainment new source review (NNSR), or the federal operating permit programs, this certification may be filed using Form APD-CERT. No fee is required for this certification.

(C) Planned MSS shall be incorporated at the next revision or update to a registration under this standard permit after January 5, 2012, and no later than any renewal submitted after December 31, 2015.

The TGTI Booster Station is proposed and is not existing; therefore, this exemption does not apply to the TGTI Booster Station.

(3) Facilities, groups of facilities or planned MSS from facilities registered under this standard permit cannot also be authorized by a permit under 30 TAC §116.111, General Application.

There are no MSS emissions at the TGTI Booster Station that are authorized under a 116.111 permit.

(4) Prior to construction or implementation of changes for any project which meets this standard permit a notification shall be submitted through the e-Permits system. This notification shall include the following:

(A) Identifying information (Core Data) and a general description of the project must be submitted through e-Permits (or if not available, hard-copy) using the "APD OGS New Project Notification."

(B) A fee of $25 for small businesses as defined in 30 TAC §106.50, or $50 for all others must be submitted through the commission's e-Pay system.

TGTI has submitted the pre-construction notification and $50 fee (Registration No. 151335) for this project via STEERS.

(5) For any registration which meets the emission limitations of this standard permit must meet the following:

(A) Within 90 days after start of operation or implemented changes (whichever occurs first), the facilities must be registered with a PI-1S Standard Permit Application.

(B) This registration shall include a detailed summary of maximum emissions estimates based on: site-specific or defined representative gas and liquid analysis; equipment design specifications and operations; material type and throughput; and other actual parameters essential for accuracy for determining emissions and compliance with all applicable requirements of this standard permit.

(C) The fee for this registration shall be $475 for small businesses, or $850 for all others.

(D) Construction may begin any time after receipt of written notification to the executive director. Operations may continue after receipt of registration if there are no objections or 45 days after receipt by the executive director of the registration, whichever occurs first.

This registration serves as the registration required for the Standard Permit and it is being submitted within 90 days after the start of operation or implemented changes. The registration includes a detailed summary of maximum emissions estimates. A fee of $850 has also been submitted via STEERS.

(6) If an OGS emissions increase, either through a change in production or addition of facilities, the site may change authorization (Level 1 or Level 2 PBR in 30 TAC §106.352 or Standard Permit) in the following circumstances:

(A) Within 90 days from the initial notification of construction of an oil and gas facility, a registration can update the authorization mechanism by submitting an initial registration or revision to the PBR or Standard Permit.

(B) Within 90 days of the change of production or installation of additional equipment, by submitting an initial registration or revision to the PBR or Standard Permit.

The preconstruction notification for this registration was identified as a Standard Permit. There has been no change to the type of authorization required.

(7) All registrations, registration revisions, and renewals shall be submitted to the commission through a PI-1S Standard Permit Registration Form. Fee requirements do not apply when there are changes in representations with no increase in emissions within 6-months after a standard permit registration has been issued.

This registration serves as the registration required for the Standard Permit and has been submitted within 90 days after the start of operation and implemented changes. The associated permit fee has also been submitted electronically through the TCEQ STEERS system since this is the initial NRSP registration and there is an associated increase in emissions.

(g) Any claim under this standard permit must comply with all applicable requirements of 30 TAC §116.610; §116.611, Registration to Use a Standard Permit; §116.614, Standard Permit Fees; and §116.615, General Conditions. This standard permit supersedes: the notification requirements of 30 TAC §116.615, General Conditions; and the emission limitations of 30 TAC §116.610(a)(1), Applicability.

The general Standard Permit requirements are addressed in Section 5 of this registration.

(h) Emission Limitations. Total maximum estimated registered or certified emissions shall meet the most stringent of the following. All emissions estimates must be based on representative worst-case operations and planned MSS activities.

(1) Total maximum estimated annual emissions of any air contaminant shall not exceed the applicable limits for a major stationary source or major modification for PSD and NNSR as specified in 30 TAC §116.12.

(2) Emissions must meet the limitations established in paragraph (k) of this standard permit.

(3) Maximum emissions are limited to less than the following after any operator limitations or controls:

Air contaminant	*steady-state or < 30 psig periodic releases lb/hr*	*≥ 30 psig periodic lb/hr up to 600 hr/yr*	*Total tpy*
*Total VOC**			*250*
*Total crude oil or condensate VOC**	*145*	*318*	
*Total natural gas VOC**	*750*	*1635*	
Benzene	*7*	*15.4*	*10.2*
Hydrogen sulfide	*10.8*	*9.8*	*47*
Sulfur dioxide	*93.2*		*250*
Nitrogen oxides	*121*		*250*
Carbon monoxide	*104*		*250*
PM10 and PM2.5	*28*		*15*

* VOC is defined in 101.1(115) and does not include methane and ethane

The total maximum emissions will meet the requirements of the Standard Permit, as illustrated in Section 3 and Appendix B of this registration.

(i) Planned Maintenance, Start-ups and Shutdowns (MSS). For any facility, group of facilities or site using this standard permit or previous versions of this standard permit, the following shall apply:

(1) Prior to January 5, 2012, representations and registration of planned MSS is voluntary, but if represented must meet the applicable limits of this standard permit. After January 5, 2012, all emissions from planned MSS activities and facilities must be considered for compliance with applicable limits of this standard permit unless otherwise specified in (b)(7). This standard permit may not be used at a site or for facilities authorized under 30 TAC §116.111 if planned MSS has already been authorized under that permit.

(2) As specified, releases of air contaminants during, or as result of, planned MSS must be quantified and meet the emission limits in this standard permit, as applicable. This analysis must include:

(A) Alternate operational scenarios or redirection of vent streams;
(B) Pigging, purging, and blowdowns;
(C) Temporary facilities if used for degassing or purging of tanks, vessels, or other facilities;
(D) Degassing or purging of tanks, vessels, or other facilities; and
(E) Management of sludge from pits, ponds, sumps, and water conveyances.

(3) Other planned MSS activities authorized by this standard permit are limited to the following. These planned MSS activities require only recordkeeping of the activity.

(A) Routine engine component maintenance including filter changes, oxygen sensor replacements, compression checks, overhauls, lubricant changes, spark plug changes, and emission control system maintenance.
(B) Boiler refractory replacements and cleanings.
(C) Heater and heat exchanger cleanings.
(D) Turbine hot standard permit swaps.
(E) Pressure relief valve testing, calibration of analytical equipment; Instrumentation/analyzer maintenance; replacement of analyzer filters and screens.

(4) Engine/compressor start-ups associated with preventative system shutdown activities have the option to be authorized as part of typical operations if:

(A) Prior to operation, alternative operating scenarios to divert gas or liquid streams are registered and certified with all supporting documentation;
(B) Engine/compressor shutdowns shall result in no greater than 4 lbs/hr of natural gas emissions; and
(C) Emissions which result from subsequent compressor start-up activities are controlled to a minimum of 98% efficiency for VOC and H_2S.

MSS activities are included in this registration and TGTI will comply with the associated recordkeeping and quantification requirements set forth within the NRSP.

(j) Records, Sampling and Monitoring. The following records shall be maintained at a site in written or electronic form and be readily available to the agency or local air pollution control program with jurisdiction upon request. All required records must be kept at the facility site. If the facility normally operates unattended, records must be maintained at an office within Texas having day-to-day operational control of the plant site. Other requirements, including but not limited to, federal recordkeeping or testing requirements, can be used to demonstrate compliance if the other requirements are at least as stringent as the associated requirements in the table below. Any documentation that is already being kept for other

purposes will suffice for demonstrating requirements. If a control or method is not relied upon to meet this standard permit, then the associated sampling, monitoring, and records are not applicable.

(1) Sampling and demonstrations of compliance shall include the requirements listed in Table 7 in paragraph (m) of this standard permit.

(2) Monitoring and records for demonstrations of compliance shall include the requirements listed in Table 8 in paragraph (m) of this standard permit.

TGTI will maintain all records as required by the Standard Permit, including records demonstrating compliance with the requirements in Table 7 and Table 8 of the NRSP.

(k) Emission Limits Based on Impacts Evaluation.

(1) All impacts evaluations must be completed on a contaminant-by- contaminant basis for only any net emissions increases resulting from a project and must meet the following as appropriate:

(A) Compliance with state or federal ambient air standards shall be demonstrated for NO_2, SO_2, and H_2S at any property-line within one mile of a project.

(B) Compliance with hourly effects screening levels (ESLs) for benzene and annual ESL for benzene, shall be demonstrated at the nearest receptor within 1 mile of a project.

(2) Distance measurements shall be determined using the following:

(A) For each facility or group of facilities, the shortest corresponding distance from any emission point, vent, or fugitive component to the nearest receptor must be used with the appropriate compliance determination method with the published ESLs as found through the TCEQ internet webpage.

(B) For each facility or group of facilities, the shortest corresponding distance from any emission point, vent, or fugitive component to the nearest property line must be used with the appropriate compliance determination method with any applicable state or federal ambient air quality standard.

(3) Impacts evaluations are not required under the following cases:

(A) If there is no receptor within 1 mile of a registration no further ESL review is required.

(B) If there is no property line within 1 mile of a registration no further ambient air quality review is required.

(C) If the project total emissions are less than any of the following rates, no additional analysis or demonstration of the specified air contaminant is required:

Air contaminant	***lb/hr***
Benzene	*0.039*
Hydrogen sulfide	*0.025*
Sulfur dioxide	*2*
Nitrogen oxides	*4*

(4) Evaluation of emissions shall meet the following.

(A) For all evaluations of NO_X to NO_2 a conversion factor of 0.20 for 4 stroke rich and lean burn engines and 0.50 for 2-stroke engines may be used.

(B) The maximum predicted concentration or rate at the property boundary or receptor, whichever is appropriate, must not exceed a state or federal ambient air standard or ESL.

(5) The impacts analysis shall be based on the following facility emissions:

(A) The following shall be met for ESL reviews:

(i) If a project's air contaminant maximum predicted concentrations are equal to or less than 10% of the appropriate ESL, no further review is required;

(ii) If a project's air contaminant maximum predicted concentrations combined with project increases for that contaminant over a rolling 60-month period after the effective date of this revised standard permit are equal to or less than 25% of the appropriate ESL, no further review is required.

(iii) In all other cases, all facility emissions at an OGS, regardless of authorization type, located within 1 mile of a project requiring registration under this standard permit shall be evaluated.

(B) The following shall be met for state and federal ambient air quality standard reviews:

(i) If a project's air contaminant maximum predicted concentrations are equal to or less than 10% the significant impact level (SIL) (also known as de minimis impact in

(ii) 30 TAC 101, General Rules), no further review is required; In all other cases, all facility emissions at an OGS, regardless of authorization type, located within 1 mile of a project requiring registration under this standard permit shall be evaluated.

(6) Evaluation must comply with one of the methods listed with no changes or exceptions:

(A) Tables.

(i) Emission impact Tables 2 – 5F in paragraph (m) of this standard permit may be used in accordance with the limits and descriptions in Table 1 in paragraph (m).

(ii) Values in Tables 2 - 5F in paragraph (m) of this standard permit may be used with linear interpolation between height and distance points. A distance of less than 50 feet or greater than 5,500 feet may not be used. Release heights may not be extrapolated beyond the limits of any table and instead the minimum or maximum height will be used. If distances and release heights are not interpolated, the next lowest height and lesser distances shall be used for determination of maximum acceptable emissions. All facilities exempted from the distance to the property line restriction in paragraph (e)(2) of this standard permit must use 50 feet as the distance to the property line for those ambient standards based on property line.

(B) Screening Modeling. A screening model may be used to demonstrate acceptable emissions from an OGS under this standard permit if all of the parameters in the screening modeling protocol provided by the commission are met.

(C) Dispersion Modeling. A refined dispersion model may be used to demonstrate acceptable emissions from an OGS under this standard permit if all of the parameters in the refined dispersion modeling protocol provided by the commission are met.

The Impacts Evaluation is discussed in detail in Section 4 of this registration.

(l) *Existing, Unchanged Facilities and Projects Before Effective Date. The requirements in 30 TAC §116.620 are applicable to existing unchanged facilities and new or changing facilities as specified in paragraph (a)(1) of this standard permit.*

The TGTI Booster Station is proposed and is not existing; therefore, this section does not apply.

(m) The following Tables shall be used as required by this standard permit.

Table 1 Emission Impact Tables Limits and Descriptions;
Table 2 Generic Modeling Results for Fugitives & Process Vents;
Table 3 Generic Modeling Results for Flares and Thermal Destruction Devices;
Table 4 Generic Modeling Results for Blowdowns, Purging, and Pigging;
Table 5A Generic Modeling Results for Engines Less Than or Equal to 250 hp;
Table 5B Generic Modeling Results for Engines Greater Than 250 hp to Less Than or Equal to 500 hp;
Table 5C Generic Modeling Results for Engines Greater Than 500 hp to Less Than or Equal to 1000 hp;
Table 5D Generic Modeling Results for Engines Greater Than 1000 hp to Less Than or Equal to 1500 hp;
Table 5E Generic Modeling Results for Engines Greater Than 1500 hp to Less Than or Equal to 2000 hp;
Table 5F Generic Modeling Results for Engines Greater Than 2000 hp Table 6 Engine and Turbine Emission and Operational Standards Table 7 Sampling and Demonstrations of Compliance;
Table 8 Monitoring and Records Demonstrations;
Table 9 Fugitive Component Leak Detection and Repair (LDAR) Control Program; and
Table 10 Best Available Control Technology (BACT) Requirements.

The aforementioned tables are used in the assessment of the applicable requirements for the NRSP. TGTI will comply with the requirements set forth in the tables, as applicable.

7. BEST MANAGEMENT PRACTICES (BMP) AND BEST AVAILABLE CONTROL TECHNOLOGY (BACT) REQUIREMENTS

For any project and any associated emission control equipment registered under the NRSP, the following requirements shall be met, as applicable.

7.1. PROGRAM TO REPLACE, REPAIR, AND/OR MAINTAIN FACILITIES

(1) All facilities which have the potential to emit air contaminants must be maintained in good working order and operated properly during facility operations. Each operator shall establish and maintain a program to replace, repair, and/or maintain facilities to keep them in good working order. The minimum requirements of this program shall include:

(A) Compliance with manufacturer's specifications and recommended programs applicable to equipment performance and effect on emissions, or alternatively, an owner or operator developed maintenance plan for such equipment that is consistent with good air pollution control practices.

(B) Cleaning and routine inspection of all equipment; and

(C) Replacement and repair of equipment on schedules which prevent equipment failures and maintain performance.

TGTI will comply with all applicable rules to maintain equipment in good working order and ensure the equipment is operated properly. TGTI will establish and maintain a program to replace, repair, and/or maintain facilities to keep them in good working order. The program will comply with the requirements outlined above.

7.2. DISTANCE LIMITATIONS

(2) Any OGS facility shall be operated at least 50 feet from any property line or receptor (whichever is closer to the facility). This distance limitation does not apply to the following:

(A) Any fugitive components that are used for isolation and or safety purposes may be located at one-half of the width of any applicable easement;

(B) Any facility at a location for which the distance requirements were satisfied at the time this standard permit is registered (provided that the authorization was maintained) regardless of whether a receptor is subsequently built or put to use 50 feet from any OGS facility; or

(C) Existing facilities which are located less than 50 feet from a property line or receptor when constructed and previously authorized. If modified or replaced, the operator shall consider, to the extent that good engineering practice will permit, moving these facilities to meet the 50 foot requirement. Replacement facilities must meet all other requirements of this standard permit.

All emission sources will be operated at least 50 feet from any property line or receptor (whichever is closer to the facility), except as allowed.

7.3. ENGINES AND TURBINES

(3) Engines and turbines shall meet the emission and performance standards listed in Table 6 in paragraph (m) and the following requirements:

(A) Liquid fueled engines used for back-up power generation and periodic power needs at the OGS are authorized if the fuel has no more than 0.05% sulfur and the engine is operated less than 876 hours per rolling 12-month period.

(B) Engines and turbines used for electric generation more than 876 hours per rolling 12-month period are authorized if no reliable electric service is readily available. In all other circumstances, electric generators must meet the technical requirements of the Air Quality Standard Permit for Electric Generating Unit (EGU) (not including the EGU standard permit registration requirements) and the emissions shall be included in the registration under this standard permit;

(C) All applicable requirements of 30 TAC Chapter 117; and

(D) All applicable requirements of 40 CFR Part 60 and 40 CFR Part 63.

(E) *Compression ignition engines that are rated less than 225 kW (300 hp) and emit less than or equal to the emission tier for an equivalent sized model year 2008 non-road compression ignition engine located at 40 CFR § 89.112, Table 1 are authorized.*

All pumps at the TGTI Booster Station will be powered by electric motors. No engines are proposed at the TGTI Booster Station. Therefore, these requirement do not apply.

7.4. OPEN-TOPPED TANKS OR PONDS

(4) Open-topped tanks or ponds containing VOCs or H_2S are allowed up to a PTE equal to 1 tpy of VOC and 0.1 tpy of H_2S.

No open-topped tanks or pods are proposed at the TGTI Booster Station; therefore, these requirements do not apply.

7.5. PROCESS EQUIPMENT AND STORAGE FACILITIES

(5) All process equipment and storage facilities individually must meet the requirements of BACT listed in Table 10 in paragraph (m). Any combination of process equipment and storage facilities with an uncontrolled PTE of equal to or greater than 25 tpy of VOC must also meet the requirements of Table 10, row titled "Combined Control Requirements". All of the following streams and facilities must be included for this site-wide assessment:

(A) For any gaseous vent stream with a concentration of 1% VOC must be considered for capture and control requirements;

(B) For any liquid stream with a potential to emit of equal to or greater than 1 tpy VOC for each vessel or storage facility.

VOC emissions for the TGTI Terminal are below 25 tpy; therefore, no add on control is required at the TGTI Booster Station. TGTI will comply with all applicable requirements in Table 10 for the Day Tank (EPN XX-XX).

7.6. FUGITIVES

(6) The following shall apply to all fugitive components associated with the project:

(a) All seals and gaskets in VOC or H_2S service shall be installed, checked, and properly maintained to prevent leaking. All components shall be physically inspected quarterly for leaks.

(b) New and replaced fugitive components and instrumentation in gas or liquid service with the uncontrolled potential to emit equal to or greater than 10 tpy VOC or 1 tpy H_2S are subject to a leak detection and repair (LDAR) program as specified in Table 9 in paragraph (m). Additional requirements are applicable where uncontrolled potential to emit equal to or greater than 25 tpy VOC or 5 tpy H_2S as specified in Table 9. Planned MSS from fugitive components must also meet the requirements of Table 9.

(c) All components found to be leaking shall be repaired. Every reasonable effort shall be made to repair a leaking component. All leaks not repaired immediately shall be tagged or noted in a log. At manned sites, leaks shall be repaired no later than 30 days after the leak is found. At unmanned sites, leaks shall be repaired no later than 60 days after the leak is found. If the repair of a component would require a unit shutdown, which would create more emissions than the repair would eliminate, the repair may be delayed until the next shutdown.

(d) Tank hatches, not designed to be completely sealed, shall remain closed (but not completely sealed in order to maintain safe design functionality) except for sampling, gauging, loading, unloading, or planned maintenance activities.

(e) To the extent that good engineering practices will permit, new and reworked valves and piping connections shall be located in a place that is reasonably accessible for leak checking during plant operation and underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

The uncontrolled VOC emissions from equipment leak fugitives are less than 10 tpy and H_2S emissions are less than 1 tpy; therefore, no LDAR program is required.

7.7. TANKS

(7) Tanks and vessels must utilize a paint color that minimizes the effects of solar heating (including, but not limited to, white or aluminum). To meet this requirement the solar absorptance should be 0.43 or less, as referenced in Table 7.1-6 in Compilation of Air Pollutant Emission Factors (AP-42). Paint shall be applied according to paint producers recommended application requirements if provided and in sufficient quantity as to be considered solar resistant. Paint shall be maintained in good condition and will not compromise tank integrity. Minimal amounts of rust may be present not to exceed 10% of the external surface area of the roof or walls of the tank and in no way may compromise tank integrity. Additionally, up to 10% of the external surface area of the roof or walls of the tank or vessel may be painted with other colors to allow for identification and/or aesthetics. For tanks and vessels purposefully darkened to create the process reaction and help condense liquids from being entrained in the vapor or are in an area whereby a local, state, federal law, ordinance, or private contract predating this standard permit's effective date establishes in writing tank and vessel colors other than white, these requirements do not apply.

TGTI will comply with all applicable requirements for painting the storage tanks, except as allowed.

7.8. ESTIMATION METHODS

(8) All emission estimation methods including but not limited to computer programs such as GRI-GLYCalc, AmineCalc, E&P Tanks, and Tanks 4.0, must be used with monitoring data generated in accordance with Table 8 in subsection (m) of this section where monitoring is required. All emission estimation methods must also be used in a way that is consistent with protocols established by the commission or promulgated in federal regulations (NSPS, NESHAPS). Where control of emissions is relied upon to meet subsection (k) of this section, control monitoring is required.

TGTI will comply will all applicable requirements for estimation methods and the associated monitoring and recordkeeping requirements in Table 8.

7.9. PROCESS REBOILERS, HEATERS, AND FURNACES AS CONTROL DEVICES

(9) Process reboilers, heaters, and furnaces that are also used for control of waste gas streams may claim 50 to 99% destruction efficiency for VOCs and H2S depending on the design and level of monitoring applied. The 90% destruction may be claimed where the waste gas is delivered to the flame zone or combustion fire box with basic monitoring as specified in paragraph (j). Any value greater than 90% and up to 99% destruction efficiency may be claimed where enhanced monitoring and/or testing are applied as specified in paragraph (j). If the waste gas is premixed with the primary fuel gas and used as the primary fuel in the device through the primary fuel burners, 99% destruction may be claimed with basic monitoring as specified in paragraph (j). In systems where the combustion device is designed to cycle on and off to maintain the designed heating parameters, and may not fully utilize the waste gas stream, records of run time and enhanced monitoring is required to claim any run time beyond 50%.

The TGTI Booster Station will not operate any of these devices as a control device; therefore, this subsection does not apply.

7.10. VAPOR RECOVERY UNITS

(10) Vapor recovery Systems (VRSs) may claim up to 100% control. The control efficiency is based on whether it is a mechanical VRU (mVRU) or a liquid VRU (lVRU). The VRUs must meet the appropriate design, monitoring and record-keeping in Table 7 and Table 8 in paragraph (m).

The TGTI Booster Station will not operate vapor recovery units; therefore, this subsection does not apply.

7.11. FLARES AS CONTROL DEVICES

(11) Flares used for control of emissions from production, planned MSS, emergency, or upset events may claim design destruction efficiency of 98% for VOCs and H2S and 99% for VOCs containing no more than three carbon atoms that contain no elements other than carbon and hydrogen. All flares must be designed and operated in accordance with the following:

(a) Meet specifications for minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring found in 40 CFR §60.18;

(b) If necessary to ensure adequate combustion, sufficient gas shall be added to make the gases combustible;

(c) An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes;

(d) An automatic ignition system may be used in lieu of a continuous pilot;

(e) Flares must be lit at all times when gas streams are present;

(f) Fuel for all flares shall be sweet gas or liquid petroleum gas except where only field gas is available and it is not sweetened at the site; and

(g) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed at total of 5 minutes during any 2 consecutive hours. Acid gas flares which must comply with opacity limits and records in accordance with 30 TAC §111.111(a)(4), Requirements for Specified Sources, regarding gas flares, are exempt from this visible emission limitation.

(h) Flares may be designed with steam or air assist to help reduce visible emissions from the flare but must meet the appropriate requirements in 40 CFR 60.18.

(i) At no time shall minimum heating values fall below the associated minimum heating value in 60.18

The TGTI Booster Station will not operate any flares; therefore, this is not applicable.

7.12. THERMAL OXIDATION AND VAPOR COMBUSTION DEVICES

(12) Thermal oxidation and vapor combustion control devices may claim design destruction efficiency from 90 to 99.9% for VOCs and H2S depending on the design and the level of monitoring and testing applied. A device designed for the variability of the waste gas streams it controls with basic monitoring to indicate oxidation or combustion is occurring when waste gas is directed to the device may claim 90% destruction efficiency. Devices with intermediate monitoring, designed for the variability of the waste gas streams they control, with a fire box or fire tube designed to maintain a temperature above 1,400 degrees Fahrenheit (F) for 0.5 seconds, residence time; or designed to meet the parameters of a flare with minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring as found in 40 CFR § 60.18, but within a full or partial enclosure may claim a design destruction efficiency of 90 to 98%. Devices with enhanced monitoring and ports and platforms to allow stack testing may claim a 99% efficiency where the devices are designed for the variability of the waste gas streams they control, with a fire box or fire tube designed to maintain a temperature above 1,400 degrees F for 0.5 seconds, residence time. The devices that can claim 99% destruction efficiency may claim 99.9% destruction efficiency if stack testing is conducted and confirms the efficiency and the enhanced monitoring is adjusted to ensure the continued efficiency. Temperature and residence time requirements may be modified if stack testing is conducted to confirm efficiencies.

The TGTI Booster Station will not operate a thermal oxidation or vapor combustion device; therefore, this is not applicable.

8.1. STATE REQUIREMENTS REVIEW

- **30 TAC Chapter 111:**
  - Emission sources at the TGTI Booster Station are not subject to the regulations listed in 30 TAC 111.111(a) and 111.151 as no sources of visible or particulate emissions are included in this project.

- **30 TAC Chapter 112:**
  - All emission sources will comply with the applicable requirements of Chapter 112, regarding the control of sulfur compounds. None of the emission sources at the TGTI Booster Station are subject to the source-specific emission limits in Chapter 112. The emissions sources at the TGTI Booster Station are expected to comply with the H_2S net ground level concentration limits.

- **30 TAC Chapter 115:**
  - The TGTI Booster Station is located in Kleberg County, which is currently not an affected county under Chapter 115. Therefore, there are no applicable requirements under this Chapter.

- **30 TAC Chapter 117:**
  - The TGTI Booster Station is located in Kleberg County, which is currently not an affected county under Chapter 117. Therefore, there are no applicable requirements under this Chapter.

8.2. FEDERAL REQUIREMENTS REVIEW

8.2.1. Part 60 – New Source Performance Standards (NSPS)

- **40 CFR Part 60 Subpart A: *General Provisions***
  - Any source subject to a source-specific NSPS is also subject to the general provisions of NSPS Subpart A. Since the sources at the TGTI Booster Station will not be subject to any individual NSPS Subpart, Subpart A is not applicable.

- **40 CFR Part 60 Subpart Kb: *Storage Vessels***
  - This subpart applies to tanks constructed, reconstructed, or modified after July 23, 1984 and with a storage capacity of greater than 39,900 gallons and vapor pressure between 0.75 psia (5.2 kPa) and 11.1. psia (76.6 kPa). The capacity of the proposed storage tank (EPN D-TK) at the TGTI Booster Station is 12,600 gallons; therefore, this subpart is not applicable to the Day tank.

- **40 CFR Part 60 Subpart KKK: *Equipment Leaks of VOC from Onshore Natural Gas Processing Plants***
  - This subpart applies to natural gas processing plants. The TGTI Booster Station is not a processing plant. Therefore, TGTI Booster Station is not subject to NSPS KKK.

- **40 CFR Part 60 Subpart LLL: *Onshore Natural Gas Processing: SO_2 Emissions***
  - This subpart applies to natural gas processing plants that use a sulfur recovery unit. The TGTI Booster Station is not a processing plant and does not utilize any sulfur recovery units; therefore, this subpart does not apply.

- **40 CFR Part 60 OOOO:** ***Crude Oil and Natural Gas Production, Transmission, and Distribution***
  - This subpart applies to Crude Oil and Natural Gas Production, Transmission, and Distribution Facilities for onshore natural gas processing plants. NSPS Subpart OOOO regulates emissions and work practice standards for compressors, condensate tanks and fugitive sources installed after August 23, 2011, and on or before September 18, 2015.
  - The proposed emissions sources at the TGTI Booster Station will be constructed after September 18, 2015; therefore, the sources proposed or affected by this project are not regulated by NSPS OOOO.

- **40 CFR Part 60 OOOOa:** ***Crude Oil and Natural Gas Facilities***
  - This subpart applies to Crude Oil and Natural Gas Facilities for which construction, modification, or reconstruction commenced after September 18, 2015. NSPS Subpart OOOOa regulates emissions and work practice standards for onshore affected facilities, such as compressors, storage tanks, pneumatic devices and pumps, and fugitive sources at oil & gas drill sites up to the point of custody transfer to oil transmission pipelines.
  - The TGTI Booster Station will receive sweet crude oil from transmissions pipelines which is after the point of custody transfer from oil & gas drill sites. As a result, NSPS OOOOa does not apply to the TGTI Booster Station.

8.2.2. Part 61 – National Emission Standards for Hazardous Air Pollutants

- **40 CFR Part 61 Subpart A:** ***General Provisions***
  - This subpart applies to any site that is subject to an individual NESHAP Subpart. Since the sources at the TGTI Booster Station will not be subject to any individual NESHAP Subpart, Subpart A is not applicable.

- **40 CFR Part 61 Subpart V:** ***Equipment Leaks (Fugitive Emission Sources)***
  - This subpart applies to sources that are intended to operate in volatile hazardous air pollutant service. This registration does not contain any sources in this service; therefore, this subpart does not apply.

8.2.3. Part 63 – National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT)

- **40 CFR Part 63 Subpart A:** ***General Provisions***
  - This subpart applies to any site that is subject to an individual MACT Subpart. Since the sources at the TGTI Booster Station will not be subject to any individual MACT Subpart, Subpart A is not applicable.

- **40 CFR Part 63 Subpart HH:** ***Oil and Natural Gas Production Facilities***
  - There are no dehydrators at the TGTI Booster Station; therefore, this subpart does not apply.

9. NNSR & PSD APPLICABILITY REVIEW

Under U.S. EPA and TCEQ rules, sites located in areas that are designated in attainment of the NAAQS for a criteria pollutant are potentially regulated under the PSD program if they are considered *major sources*. Major source thresholds are defined in 40 CFR §52.21 (b)(1)(i). The proposed site-wide VOC emissions and other criteria pollutants are below the major source thresholds under the PSD program; therefore, the TGTI Booster Station is not subject to PSD permitting.

NNSR applies to facilities located in areas designated as nonattainment for one or more of the criteria pollutants. The TGTI Terminal is located in Kleberg County, which has been designated as an attainment or unclassified area for all criteria air pollutants.[4] As a result, the NNSR program does not apply to the proposed project.

[4] The United States Environmental Protection Agency (U.S. EPA) Green Book. Source: https://www3.epa.gov/airquality/greenbook/hbcs.html#TX, accessed in November 2017.

10. PROFESSIONAL ENGINEER (P.E.) SEAL

The professional engineer (P.E.) seal is attached in this section for the proposed project.

FORM PI-1 SECTION X PROFESSIONAL ENGINEER (P.E.) SEAL

I, Beatriz Santamaria, have reviewed the following sections of the attached application for the Non-Rule Standard Permit Application submitted by Texas Gulf Terminals, Inc:

Emissions Data

Best Available Control Technology

The capital cost of the project is estimated to be greater than $2,000,000.

The application for Non-Rule Standard Permit, as referenced above, was reviewed on the 14th day of June 2018.

Signed:

STATE OF TEXAS
BEATRIZ SANTAMARIA
122116
LICENSED
PROFESSIONAL ENGINEER

Date: 06/14/2018

Professional Engineer Registration Number: 122116

Appendix A: TCEQ TABLE 1(A)

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	June 2018	**Permit No.:**	152441	**Regulated Entity No.:**	TBD
Area Name:	TGTI Booster Station			**Customer Reference No.:**	CN605490085

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN			(A) POUND/HR	(B) TPY
D-TK	D-TK	Day Tank	VOC	141.97	2.99
			Benzene	1.35	0.03
			H_2S	< 0.01	< 0.01
FUG	FUG	Fugitives	VOC	0.39	1.73
			Benzene	< 0.01	0.02
			H_2S	< 0.01	< 0.01

EPN = Emission Point Number

FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	June 2018	**Permit No.:**	152441	**Regulated Entity No.:**	TBD
Area Name:	TGTI Booster Station			**Customer Reference No.:**	CN605490085

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

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
						5. Building Height	6. Height Above Ground	7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	(Ft.)	(Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
D-TK	D-TK	Day Tank	14							Ambient			
FUG	FUG	Fugitives	14							Ambient			

EPN = Emission Point Number

FIN = Facility Identification Number

Appendix B: **DETAILED EMISSIONS CALCULATIONS**

Texas Gulf Terminals Inc.
TGTI Booster Station
Non-Rule Standard Permit Limit Comparison

Air Contaminant	Site-Wide Emission Totals			Standard Permit Limits per 6002(h).		
	Steady-state or <30 psig periodic release (lb/hr)	≥ 30 psig periodic (up to 600 hr/yr) (lb/hr)	Total (tpy)	Steady-state or <30 psig periodic release (lb/hr)	≥ 30 psig (up to 600 hr/yr) (lb/hr)	Total (tpy)
Total VOC	142.36	--	4.71	--	--	250
Total crude oil or condensate VOC	142.36	--	--	145	318	--
Total natural gas VOC	--	--	--	750	1635	--
Benzene	1.35	--	0.04	7	15.4	10.2
H_2S	3.11E-03	--	1.03E-04	10.8	9.8	47
SO_2	--	--	--	93.2	--	250
NO_x	--	--	--	121	--	250
CO	--	--	--	104	--	250
PM_{10}	--	--	--	28	--	15
$PM_{2.5}$	--	--	--	28	--	15

Texas Gulf Terminals Inc.
TGTI Booster Station
Emissions Summary

EPN / Emission Source	VOC		Benzene		H_2S			
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy		
D-TK / Day Tank	141.97	2.99	1.35	0.03	< 0.01	< 0.01		
FUG / Fugitives	0.39	1.73	< 0.01	0.02	< 0.01	< 0.01		
TOTAL:		**4.71**		**0.04**		**< 0.01**		
Maximum Operating Schedule:	**Hours/Day**	24	**Days/Week**	7	**Weeks/Year**	52	**Hours/Year**	8760

Texas Gulf Terminals Inc.
TGTI Booster Station
Day Tank Emissions Calculation

Tanks Physical Properties[1]

EPN	Description	Product Stored	Capacity (gal)	Diameter (ft)	Length (ft)	Maximum Hourly Throughput[2] (gal/hr)	Annual Throughput[3] (gal/yr)
D-TK	Day Tank	Crude/Condensate	12,600	12	21	9,000	50,400

[1] Tank physical properties are based on Project Design Document.
[2] Maximum hourly throughput conservatively based on the assumption that the tank can be filled within an hour.
[3] The annual throughput is conservatively based on four (4) pigging events per year and 300 barrels of crude/condensate loaded to the Day Tank in each pigging event (information received from TGTI on 6/11/2018).

Working and Breathing Emissions Calculation

EPN	Description	Product Stored	Max Daily Liquid Surface Temperature[1] (°R)	Vapor Pressure (P_{VA})[2] (psia)	Vapor Molecular Weight (M_V)[3] (lb/lb-mol)	VOC Emissions[4,5]		Benzene Emissions[6,7]		H_2S Emissions[8,9]	
						(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
D-TK	Day Tank	Crude/Condensate	564.67	11.00	65	141.97	2.99	1.35	0.03	3.11E-03	6.53E-05

[1] Maximum daily liquid surface temperature is assumed to be 95 °F for hourly emissions calculation per TCEQ guidance.
[2] Vapor pressure of 11 psi for crude/condensate is conservatively used for hourly emissions calculation.
[3] Molecular weight of crude oil obtained from AP-42 Table 7.1-2.
[4] Hourly emissions are calculated based on *TCEQ Air Permit Division Estimating Short Term Emission Rates from Fixed Roof Tanks* (February 2018).

$$L_{MAX} = \frac{M_V P_{VA}}{RT} FR_M$$

Where

L_{MAX}= Maximum short term emission rate, lbs/hour
M_v= vapor molecular weight, lb/lb-mole
P_{VA}= VP at max daily liquid surface temperature, psia
FR_M= Maximum filling rate, gal/hr
R= Ideal gas constant, (psia gal)/(lb-mol °R)
T= Max daily liquid surface temperature, °R

Maximum Hourly Emissions = $\frac{9{,}000 \text{ gal}}{\text{hr}} \cdot \frac{65 \text{ lb}}{\text{lb-mol}} \cdot \frac{11.000 \text{ psia}}{564.67 \text{ °R}} \cdot \frac{\text{°R lb-mol}}{80.273 \text{ psia gal}}$ = 141.97 lb/hr

[5] Annual emissions are based on AP-42 Section 7.1.3.1 (November 2006). See separate pages.
[6] Maximum benzene in crude/condensate vapor is assumed to be 0.95%
[7] Sample calculations for Benzene emissions:

Hourly Benzene Emissions: $\frac{141.97 \text{ lb/hr}}{} \cdot \frac{0.95\% \text{ lb BZ}}{1 \text{ lb VOC}}$ = 1.35 lb/hr

Annual Benzene Emissions: $\frac{2.99 \text{ tpy}}{} \cdot \frac{0.95\% \text{ lb BZ}}{1 \text{ lb VOC}}$ = 0.03 tpy

[8] Maximum ratio of H_2S in Crude/Condensate is assumed to be 2.19E-05 lb H_2S/lb VOC
[9] Sample calculations for H_2S emissions:

Hourly H_2S Emissions: $\frac{141.97 \text{ lb/hr}}{} \cdot \frac{2.19\text{E-}05 \text{ lb H2S}}{1 \text{ lb VOC}}$ = 3.11E-03 lb/hr

Annual H_2S Emissions: $\frac{2.99 \text{ tpy}}{} \cdot \frac{2.19\text{E-}05 \text{ lb H2S}}{1 \text{ lb VOC}}$ = 6.53E-05 tpy

Texas Gulf Terminals Inc.
TGTI Booster Station
Table E-11. Ancillary Diesel Storage Tank Annual Emissions Calculation

Calculation performed in accordance with AP-42, November 2006, Section 7.1.3.1.

Variable	
Tank Identification	***D-TK***
CIN	***N/A***
Discharging to	***Atmosphere***
EPN	***D-TK***
Location for Calculation Purposes	**Corpus Christi, Texas**
Tank/Roof Type	**Horizontal Tank**
Underground?	**Aboveground**
Diameter, ft	**12.0**
Shell Height or Length, ft	**21.0**
Nominal Capacity, gal	***12,600***
Breather Vent Type	***Combination Vent Valve***
Shell Paint Color	**White**
Shell Paint Condition	**Good**
Roof Paint Color	**White**
Roof Paint Condition	**Good**

	January	February	March	April	May	June	July	August	September	October	November	December
Type of Substance	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**	**Crude Oil**
Throughput, gallons/month	**4,200**	**4,200**	**4,200**	**4,200**	**4,200**	**4,200**	**4,200**	**4,200**	**4,200**	**4,200**	**4,200**	**4,200**
Effective Diameter, ft	17.9	17.9	17.9	17.9	17.9	17.9	17.9	17.9	17.9	17.9	17.9	17.9
Effective Height, ft	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Working Capacity, gal	17,767	17,767	17,767	17,767	17,767	17,767	17,767	17,767	17,767	17,767	17,767	17,767
Maximum Liquid Height, ft	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Minimum Liquid Height, ft	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Average Liquid Height, ft	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00
Vapor Space Outage, ft	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71
Vapor Space Volume, ft^3	1188	1188	1188	1188	1188	1188	1188	1188	1188	1188	1188	1188
Average Daily Minimum Ambient Temperature, F	45.30	48.00	55.30	63.20	69.50	73.40	74.80	75.00	72.30	63.90	55.60	48.40
Average Daily Maximum Ambient Temperature, F	65.00	69.00	75.70	81.70	86.20	90.40	93.30	93.40	89.70	83.90	75.80	68.30
Daily Total Solar Insolation Factor, Btu/ft^2/day	886	1132	1404	1598	1734	1929	1987	1852	1599	1367	1043	843
Daily Average Ambient Temperature, F	55.2	58.5	65.5	72.5	77.9	81.9	84.1	84.2	81.0	73.9	65.7	58.4
Tank Paint Solar Absorbance, dimensionless	0.170	0.170	0.170	0.170	0.170	0.170	0.170	0.170	0.170	0.170	0.170	0.170
Daily Vapor Temperature Range, R	18.4	20.5	21.4	20.9	20.3	21.4	22.8	22.1	20.1	20.9	19.5	18.3
Daily Average Liquid Surf. Temperature, F	56.4	60.0	67.4	74.6	80.2	84.5	86.7	86.7	83.2	75.7	67.1	59.5
Daily Minimum Liquid Surf. Temperature, F	51.8	54.9	62.1	69.4	75.1	79.1	81.0	81.2	78.1	70.5	62.2	54.9
Daily Maximum Liquid Surf. Temperature, F	61.0	65.2	72.7	79.8	85.3	89.9	92.4	92.2	88.2	81.0	72.0	64.1
Liquid Bulk Temperature	55.2	58.5	65.5	72.5	77.9	81.9	84.1	84.2	81.0	73.9	65.7	58.4
Vapor Molecular Weight, lb/lbmol	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00
Vapor Pressure at Daily Av. Liquid Surf. Temp., psia	10.25	10.16	10.14	10.15	10.19	10.14	10.09	10.12	10.19	10.16	10.21	10.26
Vapor Pressure at Daily Min. Liquid Surf. Temp., psia	9.54	9.38	9.33	9.36	9.42	9.34	9.24	9.29	9.43	9.36	9.46	9.55
Vapor Pressure at Daily Max. Liquid Surf. Temp., psia	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00
Vapor Density, lb/ft^3	0.12032	0.11847	0.11651	0.11512	0.11429	0.11289	0.11183	0.11216	0.11371	0.11490	0.11741	0.11967
Daily Vapor Pressure range, psi	1.4624	1.6161	1.6739	1.6351	1.5840	1.6645	1.7610	1.7097	1.5716	1.6330	1.5368	1.4559
Breather Vent Pressure Setting, psig	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300
Breather Vent Vacuum Setting, psig	-0.0300	-0.0300	-0.0300	-0.0300	-0.0300	-0.0300	-0.0300	-0.0300	-0.0300	-0.0300	-0.0300	-0.0300
Breather Vent Pressure Setting Range, psi	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600
Ambient Pressure, psia	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Vapor Space Expansion Factor	0.351	0.3826	0.3943	0.3857	0.3752	0.3913	0.4105	0.4004	0.3723	0.3853	0.3660	0.3495
Vented Vapor Saturation Factor	0.281	0.283	0.283	0.283	0.282	0.283	0.284	0.284	0.282	0.283	0.282	0.281
Annual Turnovers	2.84	2.84	2.84	2.84	2.84	2.84	2.84	2.84	2.84	2.84	2.84	2.84
Turnover Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Working Loss Product Factor	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
Standing Storage Loss, lb/mo	436.5031	425.8772	478.8133	447.3250	445.4034	445.4825	480.1302	468.7278	425.4016	460.7690	431.2244	432.2878
Working Loss, lb/mo	49.9704	49.5524	49.4220	49.5027	49.6573	49.4395	49.1763	49.3219	49.6767	49.5121	49.7781	50.0026
Total Losses, lb/mo	486.4735	475.4296	528.2353	496.8277	495.0607	494.9219	529.3065	518.0497	475.0783	510.2810	481.0025	482.2904

Standing Storage Loss, lb/yr	5377.9452
Working Loss, lb/yr	595.0119
Total Losses, lb/yr	5972.9571

Sample Calculations

Emissions were calculated on a pounds per month basis. The emissions for each month were then summed in order to estimate annual emissions. Monthly emissions were calculated according to the calculation methodology for fixed roof tanks explained in EPA AP-42 Chapter 7 for Organic Liquid Storage Tanks.

A sample calculation has been provided for the tank, material, and month which had the highest emissions. All Input data and intermediate calculation information has been provided.

Estimating Monthly Emissions from Fixed Roof Tanks

[LT] = [LS] + [LW]

[LS] = [MD] x [VV] x [WV] x [KE] x [KS]

[LW] = 0.001 x [MV] x [PVA] x [Q] x [KN] x [KP]

Where:

LT	Total Losses, lb/mo
LS	Standing Storage Loss, lb/mo
LW	Working Loss, lb/mo
MD	Days in month
VV	Vapor Space Volume, ft^3
WV	Vapor Density, lb/ft^3
KE	Vapor Space Expansion Factor
KS	Vented Vapor Saturation Factor
MV	Vapor Molecular Weight, lb/lbmol
PVA	Vapor Pressure at Daily Av. Liquid Surf. Temp., psia
Q	Throughput, gallons/month
KN	Turnover Factor
KP	Working Loss Product Factor

Maximum Monthly Emissions:

Material	Crude Oil
Month	July

[LT] = [480.1302] + [49.1763] = 529.3065 lbs

[LS] = [31] x [1187.5220] x [0.1118] x [0.4105] x [0.2841] = 480.1302 lbs

[LW] = 0.001 x [65] x [10.0874] x [4,200] x [1.0000] x [0.75] = 49.1763 lbs

Values for Sample Calculation

LT	529.3065	KS	0.2841
LS	480.1302	MV	65
LW	49.1763	PVA	10.0874
MD	31	Q	4,200
VV	1187.5220	KN	1.0000
WV	0.1118	KP	0.75
KE	0.4105		

Texas Gulf Terminals Inc.
TGTI Booster Station
Manifold Fugitives Emissions Calculations

Equipment/Service	Emission Factor[1] [(lb/hr)/ component]	Component Count[2]	Reduction Credit	VOC Emissions[3]		Benzene Emissions[5]		H_2S Emissions[5]	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Valves									
Light Liquid	0.0055	37	0%	0.20	0.89	1.93E-03	8.47E-03	4.45E-06	1.95E-05
Pump Seals									
Light Liquid	0.02866	6	0%	0.17	0.75	1.63E-03	7.16E-03	3.76E-06	1.65E-05
Flanges									
Light Liquid	0.000243	76	0%	0.02	0.08	1.75E-04	7.68E-04	4.04E-07	1.77E-06
			Total:	**0.39**	**1.73**	**3.74E-03**	**0.02**	**8.62E-06**	**3.77E-05**

[1] Emission Factors obtained from the *TCEQ Air Permit Technical Guidance for Chemical Sources, Fugitive Guidance,* December 2017, for Oil and Gas Production Operations.

[2] Component Count is based on Project Design Document.

[3] A VOC content of 100% was conservatively used to represent the fugitive emissions. Sample calculations for light liquid flanges VOC emissions:

$$\text{Hourly VOC Emissions} = \frac{76\ \text{component(s)}}{} \cdot \frac{0.000243\ \text{lb/hr}}{\text{component}} \cdot \frac{100 - 0\%}{\text{control}} \cdot \frac{100\%}{} = 0.02\ \text{lb/hr}$$

$$\text{Annual VOC Emissions} = \frac{0.02\ \text{lb}}{\text{hr}} \cdot \frac{8{,}760\ \text{hrs}}{\text{yr}} \cdot \frac{1\ \text{ton}}{2{,}000\ \text{lb}} \cdot \frac{100\%}{} = 0.08\ \text{tpy}$$

[4] Maximum benzene in crude/condensate vapor is assumed to be 0.95%

[5] Sample calculations for light liquid flanges Benzene emissions:

$$\text{Hourly Benzene Emissions} = \frac{0.02\ \text{lb/hr}}{} \cdot \frac{0.95\%\ \text{lb BZ}}{1\ \text{lb VOC}} = 1.75\text{E-}04\ \text{lb/hr}$$

$$\text{Annual Benzene Emissions} = \frac{0.08\ \text{tpy}}{} \cdot \frac{0.95\%\ \text{lb BZ}}{1\ \text{lb VOC}} = 7.68\text{E-}04\ \text{tpy}$$

[6] Maximum ratio of H_2S in Crude/Condensate is assumed to be 2.19E-05 lb H_2S/lb VOC

[7] Sample calculations for light liquid flanges H_2S emissions:

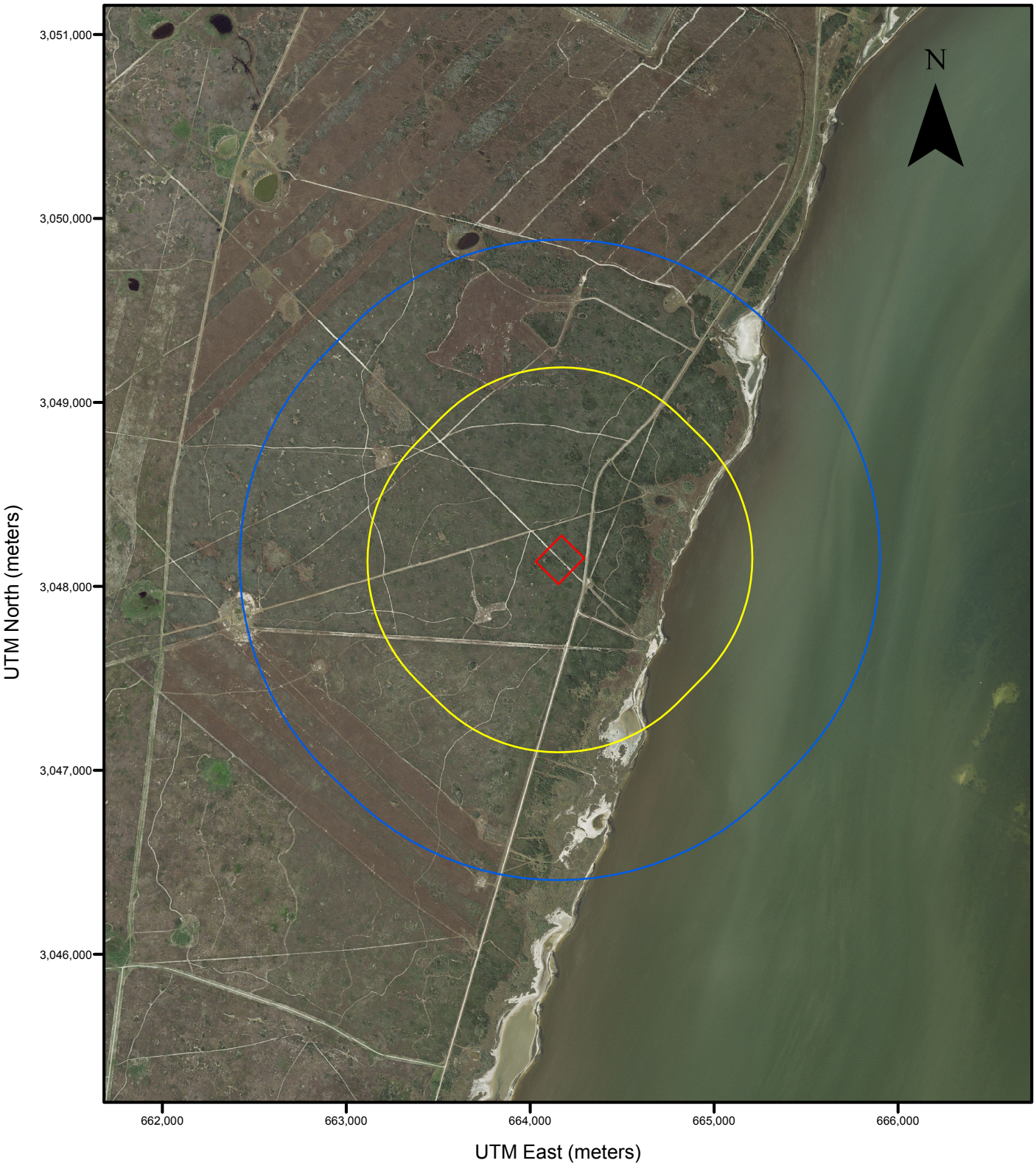
$$\text{Hourly } H_2S \text{ Emissions} = \frac{0.02\ \text{lb/hr}}{} \cdot \frac{2.19\text{E-}05\ \text{lb H2S}}{1\ \text{lb VOC}} = 4.04\text{E-}07\ \text{lb/hr}$$

$$\text{Annual } H_2S \text{ Emissions} = \frac{0.08\ \text{tpy}}{} \cdot \frac{2.19\text{E-}05\ \text{lb H2S}}{1\ \text{lb VOC}} = 1.77\text{E-}06\ \text{tpy}$$

Appendix C: **AREA MAP AND PLOT PLAN**

Texas Gulf Terminals Inc.

Booster Station Area Map



0 500 1,000 1,500 2,000

Meters

Legend

- Property Boundary
- 3000 ft Buffer
- 1 mile Buffer

Coordinate System: NAD83 UTM Zone 14N
Map: NAIP 2014 Nueces County Mosaic
Date: 06-15-2018

Trinity Consultants

Appendix D: **CORE DATA FORM**

TCEQ Use Only

TCEQ Core Data Form

For detailed instructions regarding completion of this form, please read the Core Data Form Instructions or call 512-239-5175.

SECTION I: General Information

1. Reason for Submission *(If other is checked please describe in space provided.)*

☒ New Permit, Registration or Authorization (*Core Data Form should be submitted with the program application.)*

☐ Renewal *(Core Data Form should be submitted with the renewal form)* ☐ Other

2. Customer Reference Number *(if issued)*	Follow this link to search for CN or RN numbers in Central Registry**	3. Regulated Entity Reference Number *(if issued)*
CN **605490085**		RN

SECTION II: Customer Information

4. General Customer Information | 5. Effective Date for Customer Information Updates (mm/dd/yyyy)

☒ New Customer ☐ Update to Customer Information ☐ Change in Regulated Entity Ownership
☐ Change in Legal Name (Verifiable with the Texas Secretary of State or Texas Comptroller of Public Accounts)

The Customer Name submitted here may be updated automatically based on what is current and active with the Texas Secretary of State (SOS) or Texas Comptroller of Public Accounts (CPA).

6. Customer Legal Name *(If an individual, print last name first: eg: Doe, John)* | *If new Customer, enter previous Customer below:*

Texas Gulf Terminals Inc

7. TX SOS/CPA Filing Number	8. TX State Tax ID (11 digits)	9. Federal Tax ID (9 digits)	10. DUNS Number *(if applicable)*
802978324		824956693	

11. Type of Customer: ☒ Corporation ☐ Individual Partnership: ☐ General ☐ Limited
Government: ☐ City ☐ County ☐ Federal ☐ State ☐ Other ☐ Sole Proprietorship ☐ Other:

12. Number of Employees
☐ 0-20 ☐ 21-100 ☐ 101-250 ☐ 251-500 ☐ 501 and higher

13. Independently Owned and Operated?
☐ Yes ☒ No

14. Customer Role (Proposed or Actual) – *as it relates to the Regulated Entity listed on this form. Please check one of the following:*

☐ Owner ☐ Operator ☒ Owner & Operator
☐ Occupational Licensee ☐ Responsible Party ☐ Voluntary Cleanup Applicant ☐ Other:

15. Mailing Address:							
	1401 MCKINNEY ST STE 1500						
	City	HOUSTON	State	TX	ZIP	77010	ZIP + 4

16. Country Mailing Information *(if outside USA)*	17. E-Mail Address *(if applicable)*
	Denise-Rogers@Texasgulfterminals.com

18. Telephone Number	19. Extension or Code	20. Fax Number *(if applicable)*
(832) 203-6493		( ) -

SECTION III: Regulated Entity Information

21. General Regulated Entity Information *(If 'New Regulated Entity" is selected below this form should be accompanied by a permit application)*

☒ New Regulated Entity ☐ Update to Regulated Entity Name ☐ Update to Regulated Entity Information

The Regulated Entity Name submitted may be updated in order to meet TCEQ Agency Data Standards (removal of organizational endings such as Inc, LP, or LLC.)

22. Regulated Entity Name *(Enter name of the site where the regulated action is taking place.)*

TGTI Booster Station

23. Street Address of the Regulated Entity: *(No PO Boxes)*								
	City		State		ZIP		ZIP + 4	
24. County	KLEBERG							

Enter Physical Location Description if no street address is provided.

25. Description to Physical Location:	Located 7.3 miles east, and 1.3 south, from the intersection of County Road 80 and County Road 43

26. Nearest City	State	Nearest ZIP Code
Corpus Christi	TX	78418

27. Latitude (N) In Decimal:	27.547186°		28. Longitude (W) In Decimal:	-97.337537°	
Degrees	Minutes	Seconds	Degrees	Minutes	Seconds

29. Primary SIC Code (4 digits)	30. Secondary SIC Code (4 digits)	31. Primary NAICS Code (5 or 6 digits)	32. Secondary NAICS Code (5 or 6 digits)

33. What is the Primary Business of this entity? *(Do not repeat the SIC or NAICS description.)*

CRUDE OIL AND CONDENSATE TRANSFER

34. Mailing Address:	1401 MCKINNEY ST STE 1500							
	City	HOUSTON	State	TX	ZIP	77010	ZIP + 4	

35. E-Mail Address:	DENISE-ROGERS@TEXASGULFTERMINALS.COM

36. Telephone Number	37. Extension or Code	38. Fax Number *(if applicable)*
(832) 203-6493		( ) -

39. TCEQ Programs and ID Numbers Check all Programs and write in the permits/registration numbers that will be affected by the updates submitted on this form. See the Core Data Form instructions for additional guidance.

☐ Dam Safety	☐ Districts	☐ Edwards Aquifer	☐ Emissions Inventory Air	☐ Industrial Hazardous Waste
☐ Municipal Solid Waste	☐ New Source Review Air	☐ OSSF	☐ Petroleum Storage Tank	☐ PWS
☐ Sludge	☐ Storm Water	☐ Title V Air	☐ Tires	☐ Used Oil
☐ Voluntary Cleanup	☐ Waste Water	☐ Wastewater Agriculture	☐ Water Rights	☐ Other:

SECTION IV: Preparer Information

40. Name:	Ms. Denise Rogers	41. Title:	Environmental Compliance Manager

42. Telephone Number	43. Ext./Code	44. Fax Number	45. E-Mail Address
(832) 203-6493		( ) -	Denise-Rogers@Texasgulfterminals.com

SECTION V: Authorized Signature

46. By my signature below, I certify, to the best of my knowledge, that the information provided in this form is true and complete, and that I have signature authority to submit this form on behalf of the entity specified in Section II, Field 6 and/or as required for the updates to the ID numbers identified in field 39.

Company:	Texas Gulf Terminals Inc	Job Title:	Environmental Compliance Manager
Name*(In Print)* :	Ms. Denise Rogers	Phone:	(832) 203-6493
Signature:		Date:	

Booster Station
NRSP Approval Documentation

Go To: Title V Federal Operating Permits

06/27/2018 ----------AirPermits IMS - PROJECT RECORD ----------

Project#: **287304** Status: **COMPLETE**
Project Administrative Name: **OGS NON-RULE STANDARD PERMIT FOR NEW REGISTRATION**
Project Technical Name: **TGTI BOOSTER STATION**

PROJECT ACTIONS

Permit	Action Type	Permit Type	Received Date	Permit Status	Renewal Date	Action Status	Complete Date
152441	INITIAL	STDPMT	06/27/2018	ISSUED	06/27/2028	COMPLETE	06/27/2018

Assigned Staff:
REVIEW ENG: STAFF , EPERMIT

Customer Name: **TEXAS GULF TERMINALS INC**
Legal Name: **Texas Gulf Terminals Inc.**
CN Number : **CN605490085**

Permit Information:
REGULATED ENTITY NUMBER: RN110441821

Permit	Account	Permittee Name	County	Region	City	State	Location
152441		TGTI BOOSTER STATION	KLEBERG	REGION 14 - CORPUS CHRISTI	CORPUS CHRISTI	TEXAS	7.3 MI E AND 1.3 MI S FROM THE INTERSECTION OF CR 80 AND CR 43

FEE:

Permit	Action Type	Reference	Fee Receipt Number	Fee Amount Paid	Fee Refund Amount	Fee Receipt Date	Fee Payment Type
152441	INITIAL	377910	582EA000307687	850.00		06/27/2018	CC

TRACKING ELEMENTS

TE Name	Start Date	Complete Date

PROJECT RULES:

Unit Desc	Rule Desc	On Application	Approve
OIL AND GAS PRODUCTION FACILITIES	6002 - NON RULE 2012-NOV-08	Y	Y

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Valve Station
De Minimis Documentation

MEMORANDUM

To: Ms. Denise Rogers, Texas Gulf Terminals Inc. TGTI Onshore Terminal
From: Mr. Brian Burdorf, Trinity Consultants
Date: June 26, 2018
RE: **Texas Gulf Terminals Valve Station de Minimis Air Authorization**
Texas Gulf Terminals Inc. – TGTI Onshore Terminal – Kleberg County
Customer Reference Number (No.) (CN) 605490085

Texas Gulf Terminals, Inc. (TGTI) submitted a Non-Rule Standard Permit (NRSP) registration in April 2018 to authorize the construction of a crude oil/condensate terminal known as the TGTI Onshore Terminal on the mainland near the Laguna Madre shore line in Kleberg County, Texas. The NRSP registration was approved on April 9, 2018 with the assigned Registration No. 151335. With this submittal, TGTI is proposing to construct a valve station near the TGTI Terminal (Valve Station) using de Minimis authorization under 30 TAC 116.119 (a)(1).

TGTI performed an air emissions review for the construction and operation of Valve Station. The review included potential emissions sources and air permits on or adjacent to the valve station as well as any other potential TCEQ applicable authorization required for operating the site. TGTI followed a checklist approach to determine that the pipeline isolation valve station meets the de Minimis conditions for air authorization from the TCEQ.

This de Minimis authorization includes the following attachments:

1. 30 TAC §116.119 (a)(1) Applicability
2. TGTI Construction Diagram of Pipeline Isolation Valve Station
3. TGTI Pipeline Project Map

Per the review, TGTI determined that the TGTI valve station does not require a New Source Review (NSR) preconstruction authorization and does not trigger any other applicable TCEQ environmental authorizations. See Acchment 1 for a review of the review of 30 TAC §116.119(A)(1) applicability. This review demonstrates that this TGTI pipeline isolation valve station qualifies to operate as a de Minimis air source authorized on behalf of the TCEQ Executive Director.

ATTACHMENT 1: 30 TAC §116.119 (A)(1) APPLICABILITY

30 TAC §116.119 (a)(1) Checklist

Per Title 30 TAC Section 116.119 (a)(1) categories of facilities or sources included on the list entitled "De Minimis Facilities or Sources" are considered by the commission to be de minimis. The TGTI pipeline isolation valve station meets the following four criteria and are one of the liquids or gases listed are de Minimis.

1) The sites may have a maximum of three valves;

The TGTI valve station operates two valves as shown in Figure 1 provided in Attachment 2.

2) The site is not otherwise authorized for air emissions;

The TGTI valve station is not otherwise authorized for air emissions.

3) The site is located more than 50 feet from any other stationary volatile organic compound source of the de Minimis pollutant;

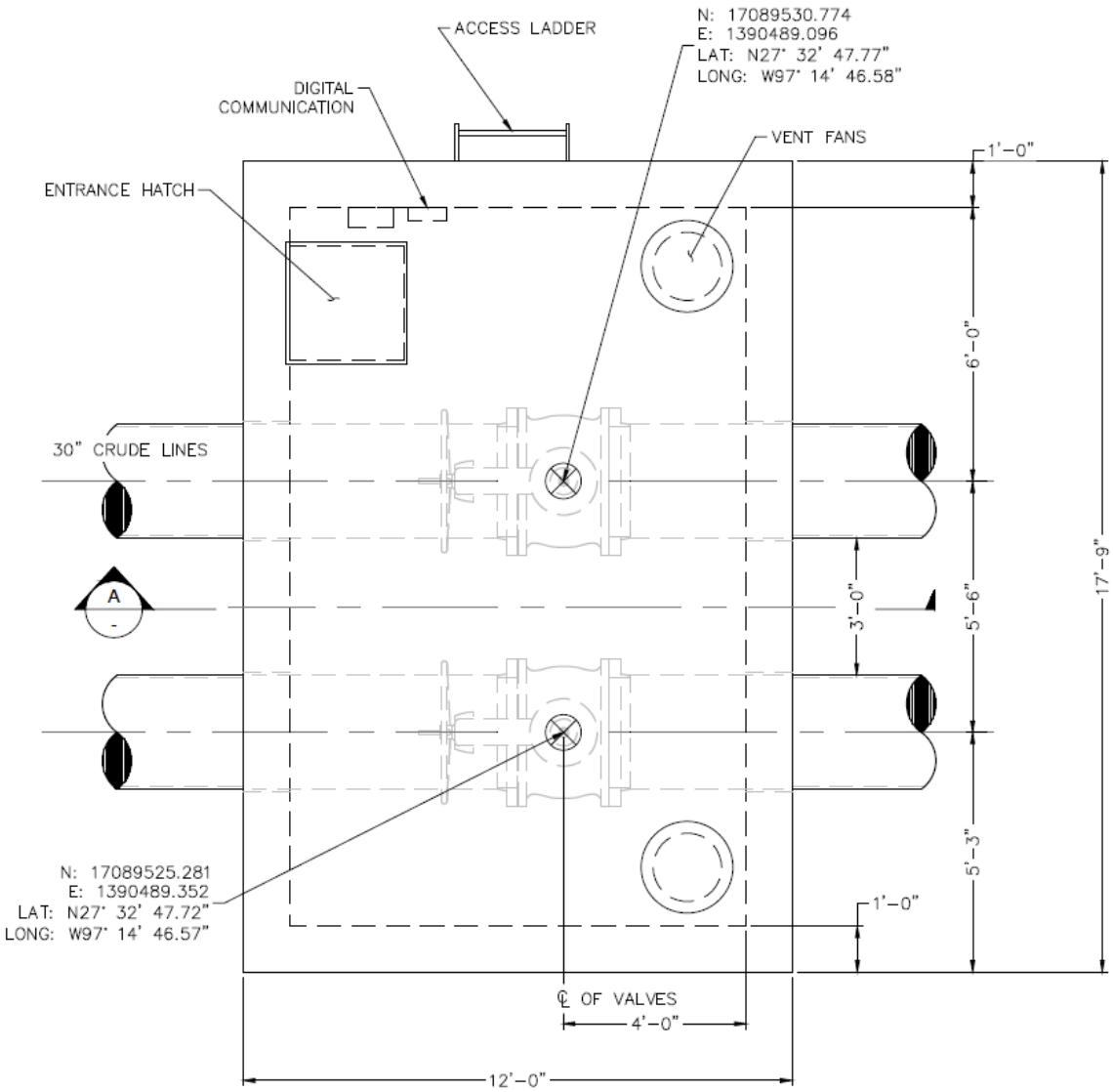
The TGTI valve station is located more than 50 feet from any other stationary volatile organic compound source of the de Minimis pollutant.

4) The pipeline does not contain a pollutant specified in an area on the TCEQ air pollutant watch list on the web.

The TGTI valve station pipeline does not contain a pollutant specific in an area on the TCEQ air pollutant watch list on the web. The pipeline will carry sweet crude oil.

ATTACHMENT 2: TGTI CONSTRUCTION DIAGRAM OF PIPELINE ISOLATION VALVE STATION

Figure 1 – TGTI Construction Diagram of Two-Valve Pipeline Isolation Valve Station



ATTACHMENT 3: TGTI PIPELINE ISOLATION VALVE STATION PLOT PLAN

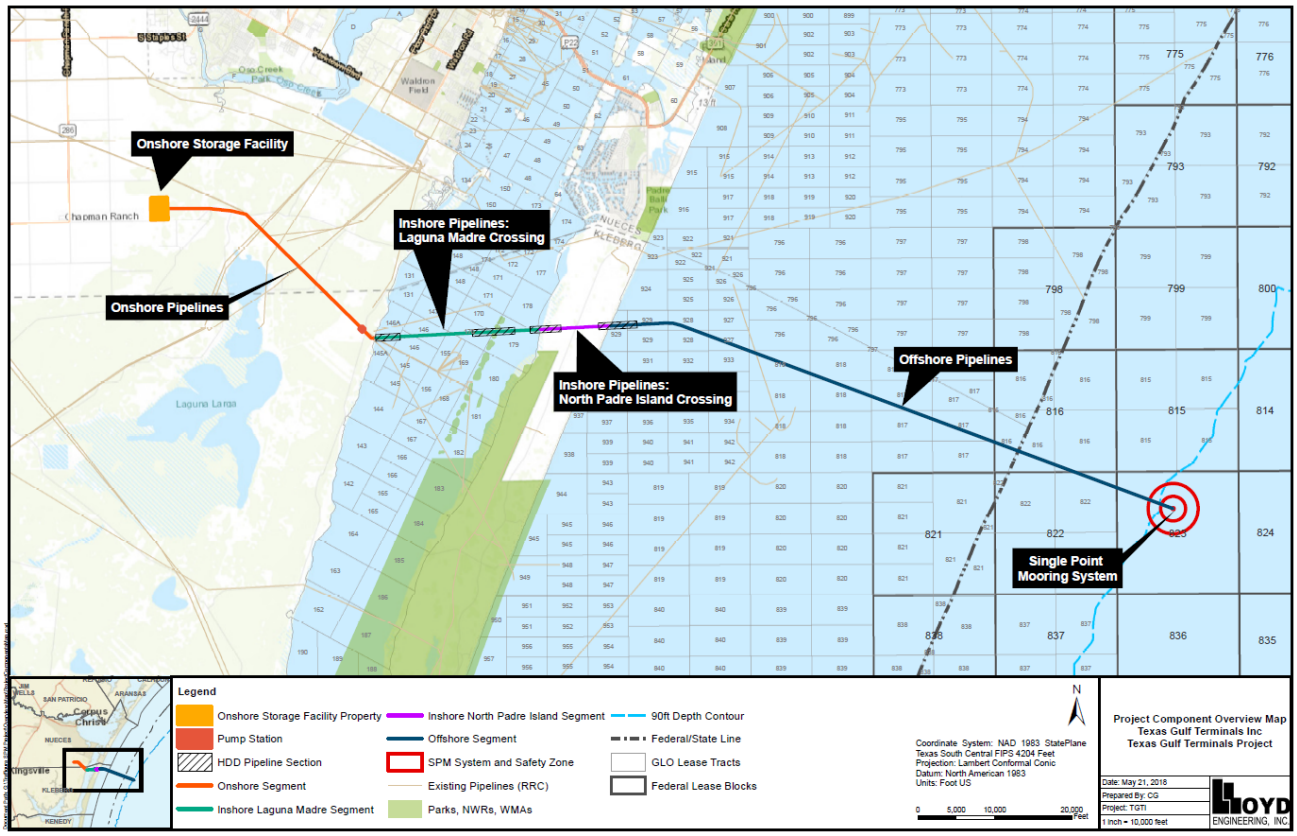



Figure 2 – TGTI Pipeline Project Map