GREENHOUSE GAS PSD
AIR PERMIT APPLICATION

ENERGY TRANSFER

ETC Texas Pipeline, Ltd.
Jackson County Gas Plant
Ganado, Jackson County, Texas

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STATE OF TEXAS
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1 INTRODUCTION

ETC Texas Pipeline, Ltd. (ETC) is applying to the Environmental Protection Agency (EPA) and to the Texas Commission on Environmental Quality (TCEQ) for authorization to construct four (4) natural gas processing plants and associated compression equipment (the Project) at the Jackson County Gas Plant (Site), which is located in Jackson County, Texas. Each of the four plants will be comprised of the following emission sources:

- two dual-drive inlet gas compressor engines,
- an amine unit, controlled by thermal oxidizer,
- a cryogenic unit,
- a molecular sieve dehydration unit,
- three electric-driven refrigeration compressors,
- a triethylene glycol (TEG) dehydration unit, controlled by thermal oxidizer,
- three natural gas-fired residue gas compressor engines,
- four natural gas-fired heaters,
- storage tanks,
- fugitives from associated piping/equipment leaks, and
- engine blowdown and starter vents, which are controlled by a flare.

The Site's existing equipment includes a slug catcher, separators, condensate stabilization unit, condensate truck loading/unloading, two pressurized condensate storage tanks, fugitives from associated piping/equipment leaks, and a flare. The existing site is a liquids handling facility that separates liquids from the gas in the pipeline and stabilizes those liquids. The gas is piped off-site. This equipment is authorized by 30 Texas Administrative Code (TAC) §106.352 and 492 (TCEQ Registration No. . After the Project is operational, the residue gas from the existing liquids handling facility will be directed to the inlet of the four processing plants.

1.1 Purpose and Overview of Application

The Project will result in increases of greenhouse gases (GHG), carbon monoxide (CO), hydrogen sulfide (H_2S), oxides of nitrogen (NO_X), particulate matter (PM, PM_{10}, and $PM_{2.5}$), sulfur dioxide (SO_2), and volatile organic compounds (VOC). The GHG are calculated as carbon dioxide equivalents (CO_2e). As discussed in more detail in Section 1.2, ETC is requesting both EPA's and TCEQ's authorization for the construction of the Project, because Texas is now under dual permitting authority.

Under EPA's authority, the Project will constitute a new major source of GHG, because the Project-related GHG emissions will be greater than the major source thresholds of 100,000 tons per year (T/yr) CO_2e and 250 T/yr GHG mass. Therefore, the Project triggers Prevention of Significant Deterioration (PSD) review for GHG. **This document constitutes ETC's application to EPA for a PSD Permit for GHG emissions from the Site.**

Under TCEQ's authority, the Project will constitute a new major source, because the Project-related CO emissions will be greater than the major source threshold of 250 T/yr. Moreover, the Project-related NO_X, PM, PM_{10}, $PM_{2.5}$, and VOC emissions will be greater than their respective PSD significance thresholds, triggering PSD review. Therefore, concurrently with this submittal, ETC is submitting a PSD air permit application document to TCEQ for the other criteria air pollutants, and ETC is providing a copy of this application to EPA.

This document has been prepared based upon information provided by ETC and written and verbal EPA and TCEQ guidance. The remainder of this document is structured as follows:

- Section 2 presents a description of the proposed Site, including area maps, plot plans, a process description, and process flow diagrams;
- Section 3 presents a discussion of the proposed Site GHG emissions, the methodologies used to estimate the GHG emissions, and the monitoring methods that ETC proposes to implement for demonstrating compliance with the proposed GHG emission rates;
- Section 4 presents a detailed demonstration that the Site will implement Best Available Control Technology (BACT);
- Section 5 identifies the state and federal regulations that apply to the Site;
- Section 6 describes the Air Quality Analysis (AQA) performed for the Project; and
- Section 7 presents a list of references used in the preparation of this GHG PSD air permit application document.

This document also contains the following appendices:

- Appendix A contains the applicable TCEQ permit application forms and tables;
- Appendix B presents detailed GHG emission rate calculations;
- Appendix C contains vendor specifications for the Project equipment, in support of the Appendix A equipment tables and Appendix B emission rate calculations;
- Appendix D contains the documentation in support of the Section 4 BACT analysis; and
- Appendix E contains documentation in support of the remainder of the air permit application.

1.2 PSD Applicability

Beginning on January 2, 2011, GHG are a regulated criteria pollutant under the PSD major source permitting program codified in Title 40 Code of Federal Regulations (CFR) Part 52 when they are emitted by new sources or modifications in amounts that meet the Tailoring Rule's set of applicability thresholds, which phase in over time. For PSD purposes, GHGs are a single air pollutant defined as the aggregate group of the following gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), and hydrofluorocarbons (HFCs).

For GHGs, the Tailoring Rule does not change the basic PSD applicability process for evaluating whether there is a new major source or modification. The applicability threshold for the source is based on CO_2 equivalent (CO_2e) emissions as well as its GHG mass emissions. Permits issued (and associated construction commenced) after July 1, 2011 and before June 30, 2013 fall into Step 2 of the Tailoring Rule. Therefore, PSD permitting requirements will for the first time apply to new construction projects that emit GHG (CO_2e) emissions of at least 100,000 tons per year (T/yr), regardless of whether they exceed the PSD permitting thresholds for any other criteria air pollutant.

Because ETC is proposing the installation of a source in an area designated as attainment/unclassifiable for all criteria air pollutants, the Project has been reviewed for potential applicability of PSD permitting requirements only. (That is, the Project is not subject to nonattainment review.) As stated previously, the Project constitutes a new major source, as defined in 40 CFR §52.21, because its potential GHG emissions are greater than 100,000 T/yr of CO_2e and greater than 250 T/yr GHG mass and because its CO emissions are greater than 250 Tyr.

In December 2010, EPA finalized a rule that designates EPA as the permitting authority for GHG emitting sources in Texas by declaring a partial disapproval of the Texas State Implementation Plan (SIP). This rule is in effect until the EPA approves a SIP that allows Texas to regulate GHG. At this time, EPA is the designated permitting authority for all GHG PSD permits in Texas. Accordingly, ETC is submitting a PSD air permit application to EPA for GHG only. As EPA stated in its white paper titled Issuing Permits for Sources with Dual PSD Permitting Authorities, dated April 19, 2011, "[i]n the case of a source or project that has both GHGs and non-GHGs that are subject to PSD . . . the State will issue the non-GHG portion of the permit and EPA will issue the GHG portion." See *http://www.epa.gov/nsr/ghgqa.htm*.

Accordingly, per EPA's direction, ETC concurrently is submitting a PSD permit application to TCEQ for the remaining criteria pollutants because the facility's CO emissions are greater than the major source threshold and those emissions are subject to PSD. Under TCEQ's PSD program, this source would be a major PSD source regardless of the GHG emissions. ETC is providing a courtesy copy of this application under a separate cover. The PSD permit application submitted to TCEQ for the criteria pollutants is not part of the permitting record for this permitting action for GHG emissions.

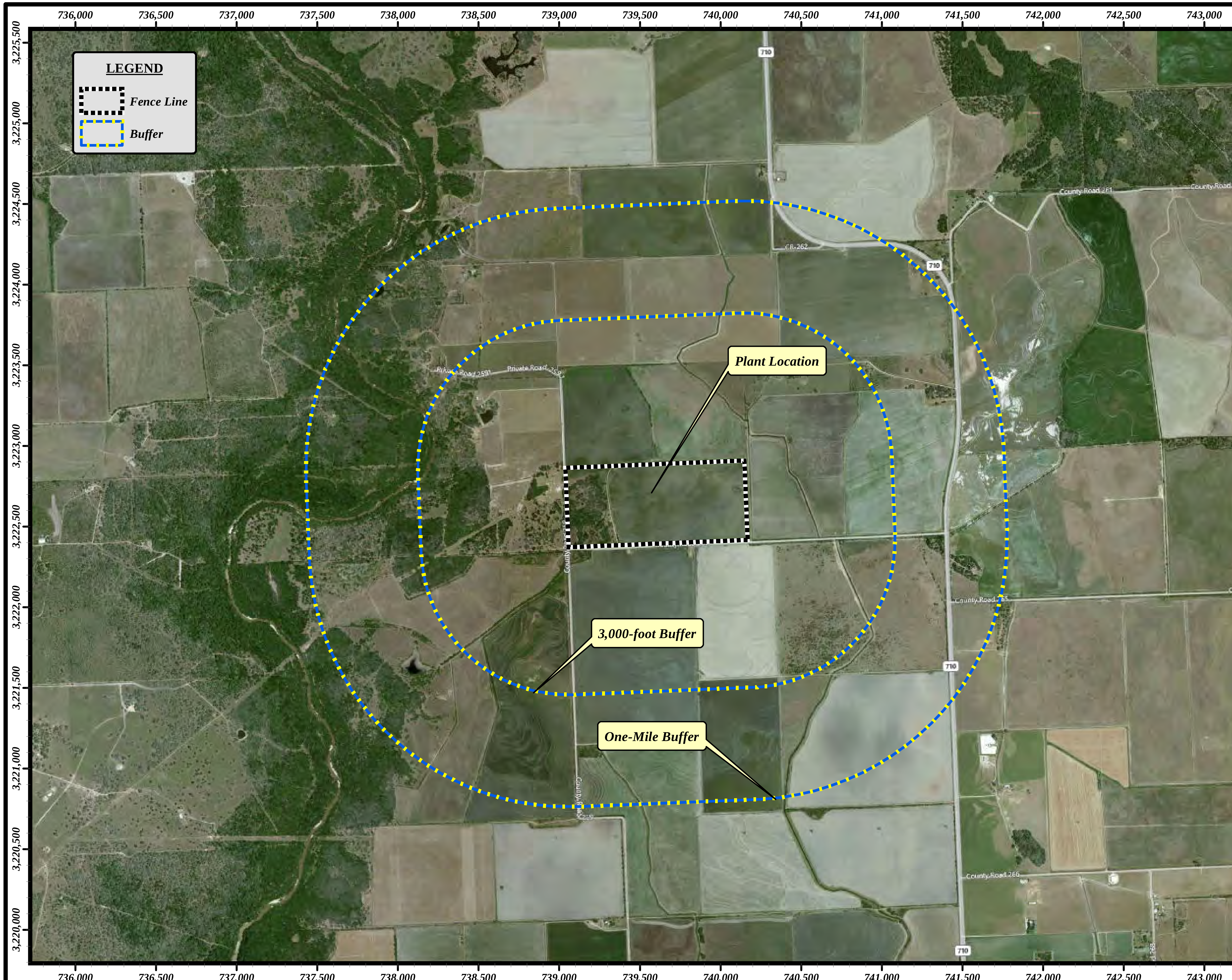
2 PROCESS/PROJECT DESCRIPTION

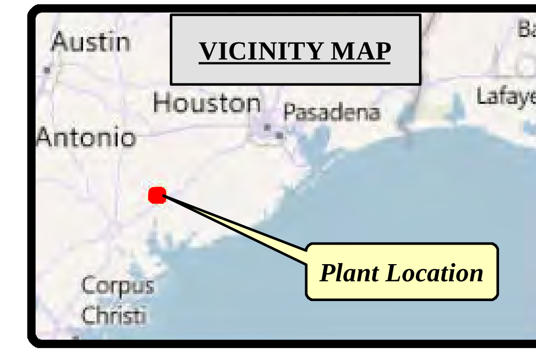
This section provides an overview of the proposed Project location and operations. As stated previously, the proposed Project includes construction of Jackson County Gas Plants 1 through 4 (which together with the existing authorized equipment comprise "the Site"). Figure 2-1 is an area map for the site, showing the Site fence line, property owner's plat, and surrounding area. As shown in Figure 2-1, there are no schools within 3,000 feet of the proposed Project location. Figure 2-2 is a map showing the site location and the nearest federal Class I areas (i.e., all of which are over 500 kilometers [km] from the Site).

Upon completion of the Project, the Site will be comprised of the following emission sources:

- eight dual-drive inlet gas compressor engines (two per Plant),
- four amine units, each controlled by thermal oxidizer (one per Plant),
- four cryogenic units (one per Plant),
- four molecular sieve dehydration units (one per Plant),
- twelve electric-driven refrigeration compressors (three per Plant),
- four triethylene glycol (TEG) dehydration units, each controlled by thermal oxidizer (one per Plant),
- twelve natural gas-fired residue gas compressor engines (three per Plant),
- engine blowdown and starter vents, which are controlled by a single flare,
- sixteen natural gas-fired heaters (four per Plant),
- one flare (servicing all four Plants),
- two vertical fixed roof (VFR) produced water storage tanks,
- produced water truck loading operations,
- fugitives from associated piping/equipment leaks (one designated fugitive area per Plant),
- miscellaneous support equipment, including lube oil tanks, antifreeze tanks, and waste oil tanks,
- one condensate stabilization unit (existing, not part of the Project),
- one natural gas-fired heater for the stabilization unit (existing, not part of the Project),
- two pressurized condensate storage tanks (existing, not part of the Project),
- condensate pressurized truck unloading operations (existing, not part of the Project),
- condensate pressurized truck loading operations, controlled by a flare (existing, not part of the Project),
- a truck loading flare (existing, not part of the Project), and
- fugitives from associated piping/equipment leaks in the Stabilization Unit (existing, not part of the Project).

Figures 2-3 and 2-4 are plant layout diagrams showing the locations of the proposed emission sources. Figure 2-5 is a simplified process flow diagram for the Site's operations. The following paragraphs present the Site's proposed operating configuration, which will be in continuous year-round operation (i.e., 8,760 hours per year [hr/yr]).





Site Boundary provided by Hatch Mott MacDonald as 141.0462 acre surface site sealed 4/18/2011, received 7/19/2011.

0 2,000 4,000
Feet

Grid Presented is NAD83, UTM 14N (meters)

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FIGURE 2-1 AREA MAP

Jackson County Gas Plant
ETC Texas Pipeline, Ltd.
TITAN Project No. 369-05
August 2011

from USGS Quadrangles Ganado NE & Ganado, Texas
Bing Map Ground Condition Depicted January 2009
Digital Data Courtesy ESRI Online

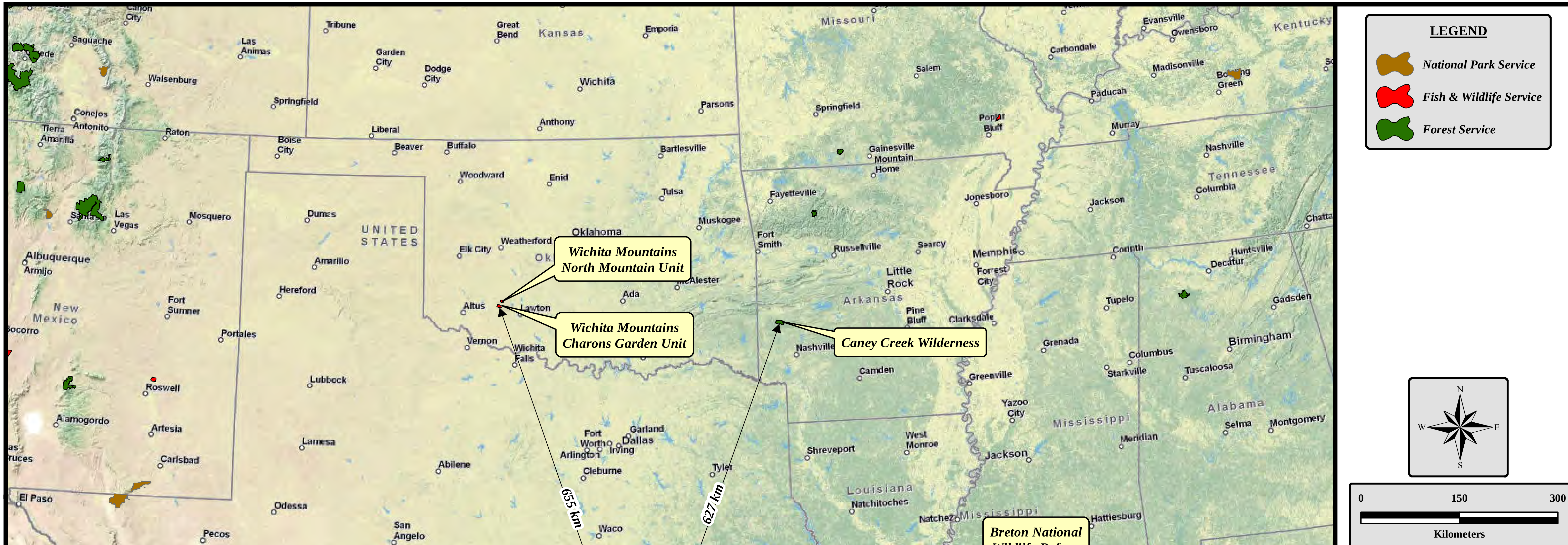

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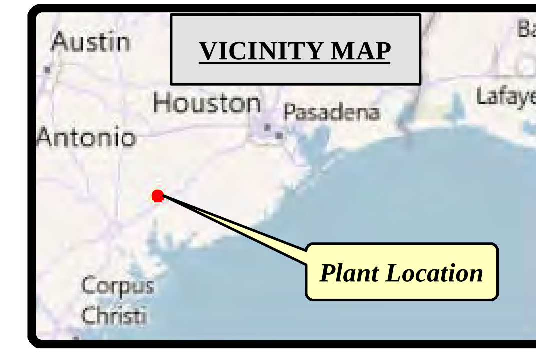
FIGURE 1-2 CLASS 1 AREAS

Jackson County Gas Plant
ETC Texas Pipeline, Ltd.
TITAN Project No. 369-05
August 2011

Class 1 Receptor Data Courtesy
National Park Service
Digital Data Courtesy ESRI Online



Site Boundary provided by Hatch Mott MacDonald as 141.0462 acre surface site sealed 4/18/2011, received 7/19/2011.

- *Magenta denotes Existing Equipment*
- *Green denotes Proposed Equipment*

0 400 800
Feet

Grid Presented is NAD83, UTM 14N (meters)

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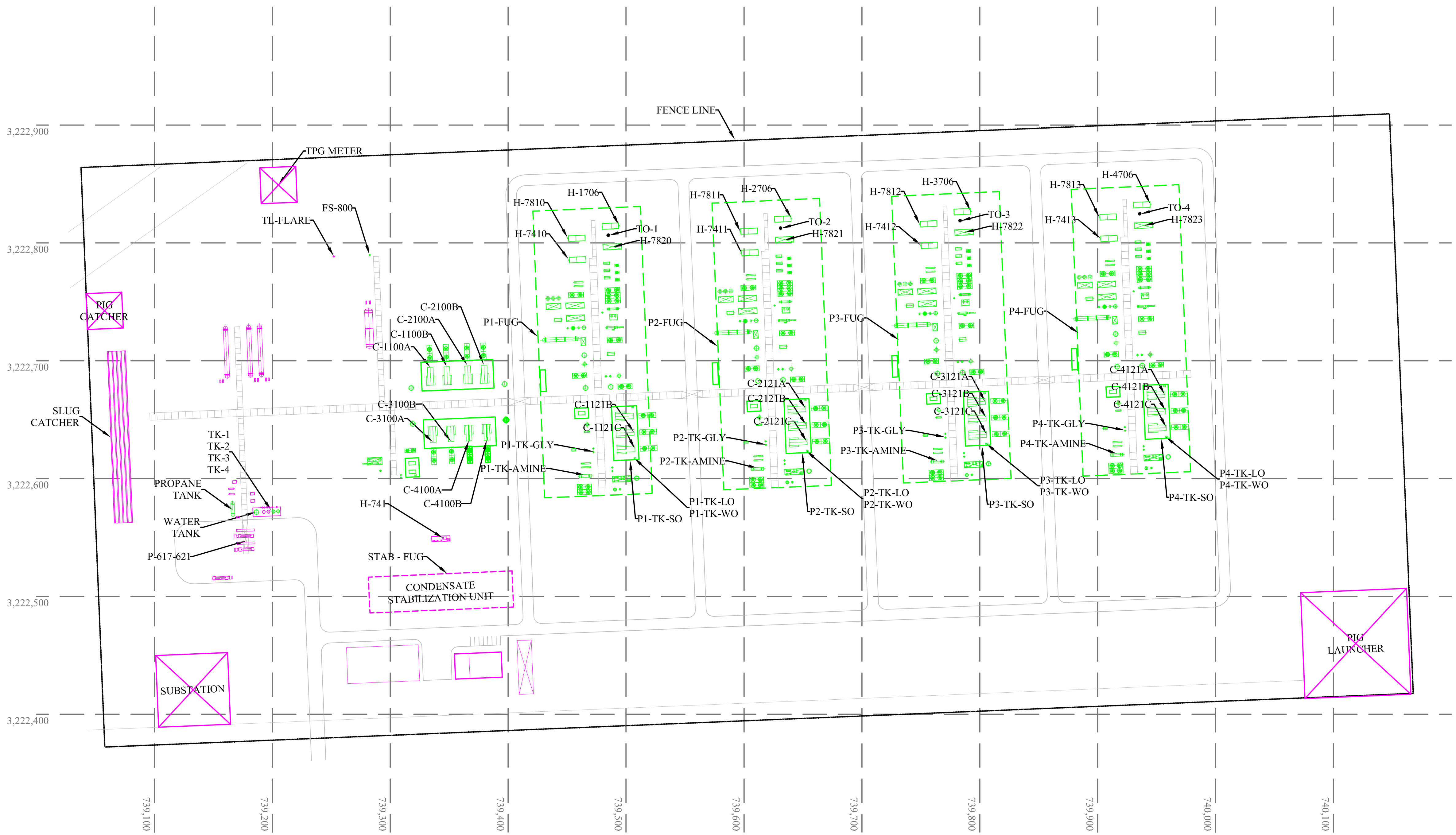
FIGURE 2-3
PRELIMINARY SITE LAYOUT (Aerial)

Jackson County Gas Plant
ETC Texas Pipeline, Ltd.
TITAN Project No. 369-05
August 2011

from USGS Quadrangles Ganado NE & Ganado, Texas
Bing Map Ground Condition Depicted January 2009
Digital Data Courtesy ESRI Online



NOTES

Magenta denotes Existing Equipment

Green denotes Proposed Equipment

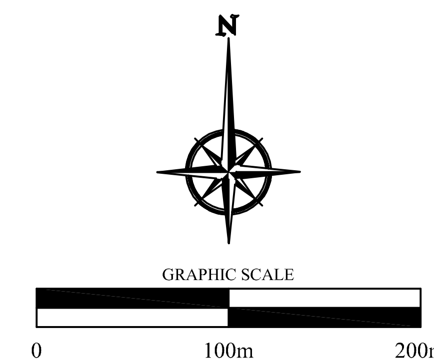


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FIGURE 2-4
PRELIMINARY SITE LAYOUT (Plot Plan)

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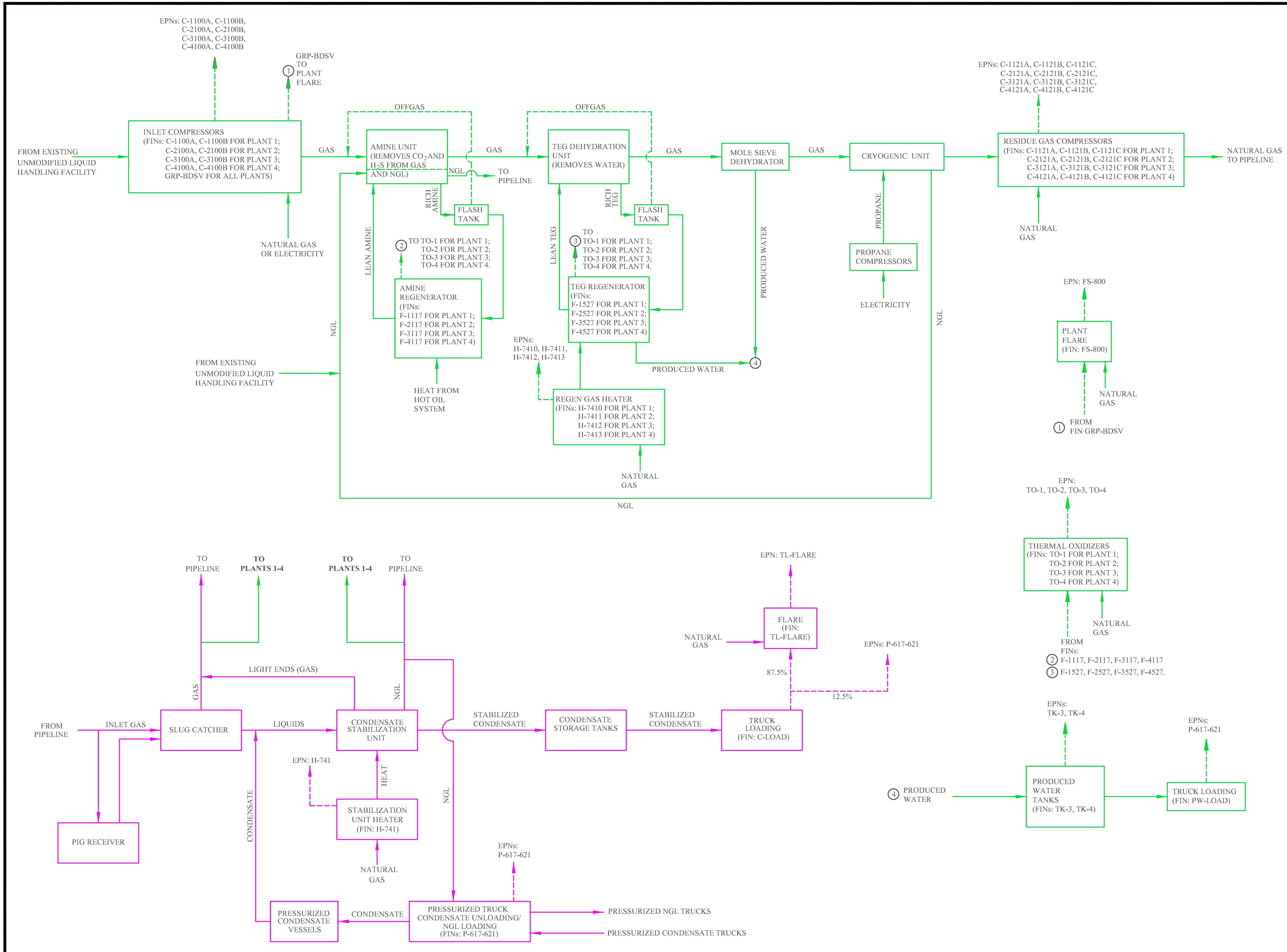
Jackson County Plant
ETC Texas Pipeline, Ltd.

DESIGNED BY:	DETAILED BY:	CHECKED BY:
LLA	LWM	DG
FILE NAME: T:\EnergyTrans\JacksonCounty\Mode\AQA\Figures		
DATE: 12/2011	PROJECT NO.: 369-05	PLOT SCALE: 1"=100 m
DRAWING NO.: TEI-36905-02	REVISION: 2	FIGURE: **3-2**



NOTES

Magenta denotes Existing Unmodified Equipment

Green denotes Proposed Equipment

—— = Process Flow

– – – = Air Emissions Stream

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FIGURE 2-5
SIMPLIFIED PROCESS FLOW DIAGRAM

ENERGY TRANSFER

Jackson County Gas Plant
ETC Texas Pipeline, Ltd.

DESIGNED BY: LLA	DETAILED BY: ODL	CHECKED BY: SRE
FILE NAME:		
DATE: 08/2011	PROJECT NO.: 369-05	PLOT SCALE: NTS
DRAWING NO.: TEI-36905-02	REVISION: 0	FIGURE: 2-5

2.1 Existing Liquids Handling Facility

As stated previously and depicted on Figures 2-3 and 2-4, the Site location currently includes a Liquids Handling Facility, which is not being modified as part of the Project.

Gas from the pipeline passes through horizontal separators, or slug catchers, which separate entrained liquids from the inlet gas. In addition, condensate can be received via pressurized trucks or through "pigging" operations. "Pigging" is an industry term to describe a pipeline maintenance activity, in which a solid slug, called a "pig" is inserted into the pipeline at a "pig launcher." As the pig travels through the pipeline with the natural gas, it pushes liquids that have collected in lower areas of the pipeline. The liquids and the pig that is pushing the liquids arrive at a "pig receiver" down downstream of the "pig launcher." The liquids are routed into the slug catcher. The residue gas is currently sent off-site via pipeline. After the Project, the residue gas will be sent to the four Plants for processing.

The vapor pressure of the separated condensate is reduced by the stabilization process (application of heat provided by the Stabilization Unit Heater), where the lighter components are removed and combined with the residue gas for shipping off-site via pipeline (i.e., and transfer to the four plants after the Project). Currently, light-end liquid components driven off in the stabilization process (natural gas liquids, or NGL) are shipped off-site via pipeline or by pressurized truck loading. After the project, these components will be routed to the NGL amine contactors at the four plants for removal of CO_2 and H_2S in order to provide a cleaner product.

The trucks bringing pressurized condensate to the Plants from the field unload into pressure vessels at the site. The condensate unloading and NGL loading operations are performed under pressure, in order to prevent emissions to the atmosphere. Therefore, the only emissions associated with these unloading/loading activities are from residual material in the connectors.

The stabilized condensate is stored in two pressurized storage tanks and then shipped off-site via truck loading. The stabilized condensate loading facilities are equipped with an electric vapor recovery unit (VRU) system. Based upon TCEQ guidance, the VRU system has been given a 98.7% capture efficiency based upon the inspection schedule of the tanker trucks (i.e., as required by 40 CFR Subpart 60, Subpart XX). Emissions captured by the VRU are routed to the Truck Loading Flare for 98% destruction of VOC. When the VRU is down for maintenance, Truck Loading does not occur.

The GHG emissions from these existing operations are from:

- Combustion of natural gas in the Stabilization Unit Heater (EPN H-741),
- Combustion of natural gas and waste gas in the Truck Loading Flare (EPN TL-Flare), and
- Piping component leaks of inlet gas that contain CO_2 and methane (EPN STAB-FUG).

The Liquids Handling Facility does not have any startup, shutdown, or maintenance-related GHG emissions that would exceed normal operating emissions. Therefore, any final permitting limits for GHG on these sources will include periods of startup, shutdown, and maintenance, and no separate emission limit is necessary for these periods.

2.2 Proposed Project Processes

As discussed previously, the Project includes the installation of four gas processing plants. The following paragraphs describe the processes associated with these plants.

2.2.1 Gas Compression

The compressors are used to increase the pressure of the gas. As the gas travels through pipelines and through the plant processes, the gas loses pressure or energy due to the friction on the pipe walls or as part of the process. Each of the four Plants is designed to have two inlet compressors with dual-drive Caterpillar 3606 engines, three refrigeration compressors with electric-driven engines, and three residue compressors with gas-fired Caterpillar 3616 engines. Currently, dual-drive technology does not have a Caterpillar 3616 model available; therefore, ETC is only proposing dual-drive technology for the Caterpillar 3606 engines. Dual-drive technology allows the engines to be operated on both natural gas and electricity.

All of the compressor engines with gas firing capability will be 4-stroke lean-burn engines, with ultra-lean burn ("Clean Burn") technology that results in a NO_X performance level of 0.5 grams per brake horsepower hour (g/hp-hr).

The dual-drive Caterpillar 3606 engines will have the option of being powered by electricity. This technology is a new and innovative technology for reducing air emissions of all pollutants, including GHG, from compressor engines. Appendix E contains information pertaining to this technology, which has received an Environmental Excellence Award for Innovative Technology in 2009 from the TCEQ. The dual-drive engines will have gas-fired operations limited to an average of 3,500 hr/yr each, and they will primarily be operated using gas during peak electrical seasons and when electrical supply to the Site is insufficient or unavailable. The Site is designed to operate continuously, but electrical supply to the Site can vary, depending upon the loads experienced by the electrical supplier. In order to avoid blackouts or rolling brownouts during periods of high electricity usage, ETC can switch to gas-fired operations, thus providing the electricity supplier with added availability during high demand periods without the supplier needing to build additional generating capacity. In these circumstances, electricity will be made available to more dependent end users (i.e., residences, schools, hospitals, businesses, etc.).

For operational flexibility, ETC is proposing to have a combined gas-fired operating limit for the inlet compressors of 28,000 hours (i.e., 3,500 * 8 = 28,000). With this combined limit, certain engines may exceed 3,500 hr/yr, as long as the total for all engines does not exceed the combined limit. This operational flexibility is needed particularly during the initial start-up of the Site, so that certain engines can be operated longer on gas until adequate electric substations are installed. Another example of required flexibility would be in the hypothetical case where the Site's electricity usage must be curtailed significantly for an extended period of time. In this case, rather than shut down all Plants at the same time, ETC would be able to develop a strategy for earlier shut down of a portion of the Site and continued operation of a portion of the Site, so that natural gas processing and delivery may be reduced, but not interrupted.

The limitation on gas-fired operations will result in a reduction of approximately 60% for all pollutants, including GHG, on an annual basis.

The residue gas compression Caterpillar 3616 engines do not have the option of being powered by electricity. There is no Original Equipment Manufacturer that sells this type of engine incorporating dual drive technology at this time.

All engines have associated startup and shutdown emissions addressed in this application. Each inlet or residue engine has an associated starter vent, through which a small amount of natural gas (containing CO_2 and methane) and is emitted during engine startup. These emissions are routed to the flare for combustion, which generates GHG emissions. Routing these emissions to the flare is environmentally beneficial because of the high destruction of VOC emissions, including methane. Given expected normal operations, engine startups are limited to 30 minutes, once per hour and 200 times per year for inlet/residue compression.

Each compressor is equipped with a blowdown vent through which a small amount of natural gas (containing CO_2 and methane) is emitted during shutdown (i.e., for decompression, which is required for safety purposes). Note that these emissions are re-routed back to the inlet suction when possible. Otherwise, they are routed to the flare, which generates GHG emissions. Given expected normal operations, engine blowdowns to flare are limited to 30 minutes, once per hour and 72 times per year per engine for inlet/residue compression and 12 times per year per engine for refrigeration compression.

The flare will have one GHG emission limit, which will include normal operations (i.e., pilot fuel-firing) and scheduled maintenance, startup, and shutdown (MSS) emissions (combustion of starter and blowdown vent emissions).

With respect to scheduled maintenance, ETC anticipates operating each engine without controls for the purpose of combustion tuning at initial startup (called the "burn-in" period). However, this "burn-in" period will not impact the fuel firing rate, upon which GHG emissions estimates are based. Therefore, the burn-in operations are not addressed separately in this GHG PSD air permit application.

2.2.2 Hot Oil Systems

The purpose of the hot oil systems is to provide heat to the plant processes. By using oil, the heat can be transferred to the Project processes with a minimum loss of heat to the oil, allowing for a quicker recovery to the desired temperature in a closed-loop system. The hot oil system is a network of piping that circulates hot oil through each of the four Plants and provides heat as needed in various areas of the plants. ETC plans to utilize the hot oil systems as needed to:

- Provide heat needed in the amine regeneration units,
- Provide heat needed in the mole sieve regeneration units, and
- Provide heat as needed to various heat exchangers within the Plants (strictly piping to maintain desired temperatures on process streams).

Each plant has four heaters:

- a 48.45 MMBtu/hr hot oil heater,
- a 17.4 MMBtu/hr trim heater,
- a 3 MMBtu/hr TEG dehydration unit heater, and
- a 9.7 MMBtu/hr mol sieve regenerator heater.

The combustion of natural gas in the hot oil heaters and TEG dehydration unit regenerator heaters results in combustion-related GHG emissions. The heaters are not expected to have GHG emissions in excess of the proposed allowable emission rates during periods of startup, shutdown, or maintenance, because the fuel firing rates will be below the maximum rate and proper combustion commences very quickly.

2.2.3 Amine Units

The Amine Units use amine contactors to remove the CO_2 and H_2S from the gas and NGL streams. Some hydrocarbons are also absorbed in the process. The rich amine is routed to amine reboilers, where heat from the hot oil system enables the volatilization of the CO_2, H_2S, and hydrocarbons (primarily VOC) in the rich amine stream. The lean amine is then returned to the amine contactors for reuse. This system is a closed-loop system. The waste gas from each amine regenerator is routed to a thermal oxidizer for combustion of H_2S and VOC, which generates SO_2 and CO_2.

Each plant is equipped with an Amine Unit and associated thermal oxidizer. The Amine Unit flash tank emissions are recycled back into the plant process. The Amine Unit waste gas is routed to each plant's respective thermal oxidizer. Each thermal oxidizer is designed to combust low-VOC concentration gas and has a fuel rating of 7 MMBtu/hr, which keeps the temperature in the combustion chamber at or above 1,400 °F. The thermal oxidizers generate combustion-related GHG emissions.

2.2.4 TEG Dehydration Units

The triethylene glycol (TEG) dehydrator units use TEG to remove water from the gas. Rich glycol is routed from the glycol contactor towers to the glycol reboilers, where heat from dedicated regeneration heaters is used to drive off the water from the glycol. Lean glycol is then returned to the contactors for reuse. The rich glycol flash tanks are not vented to the atmosphere, but are routed back to the unit for reprocessing. The glycol regenerator still vent at each plant is routed to its respective thermal oxidizer for emission control, which results in combustion-related GHG emissions.

2.2.5 Molecular Sieve Dehydration Units

From the TEG Units, the gas is routed to the molecular sieve dehydration units, where the water content is reduced further. The hot oil system heats a small amount of natural gas that is slip-streamed from the residue line as needed to regenerate the beds. The gas is then routed back into the system. There are four (4) beds in each molecular sieve, and one (1) bed is regenerated at a time. The molecular sieve units do not have vents to atmosphere. The residue gas from the beds that are regenerated is routed back to the residue gas stream. Therefore, the only GHG emissions from these units are associated with fugitive piping/equipment leaks.

2.2.6 Cryogenic Units

After the molecular sieve dehydration units, the propane-cooled cryogenic units remove heavier components to produce natural gas liquids (NGL) by cooling the stream and reducing the stream pressure. The natural gas leaving the cryogenic unit is lean and dry (i.e., pipeline quality). The NGL liquids are transferred back to the Amine Units for processing prior to exiting the Site via pipeline. The only GHG emissions from these units are associated with fugitive piping/equipment leaks.

2.2.7 Storage Tanks

The plants will use two 300-barrel produced water tanks (TK-3 and TK-4). None of the tanks will result in GHG emissions.

2.2.8 Loading Operations

Produced water will be trucked off-site via atmospheric loading. This loading operation will not emit GHG.

2.2.9 Equipment Components (Piping)

Fugitive emissions, including CO_2 and methane, may result from piping equipment leaks. The piping that may leak includes valves, flanges, pump seals, etc. ETC will be implementing the TCEQ 28LAER Leak Detection and Repair (LDAR) program for the entire Site.

3 AIR EMISSIONS

Section 3.1 describes the GHG emissions associated with the proposed Project. Section 3.2 describes the BACT to be implemented at the four Plants. Section 3.3 describes the emission calculation methodologies used to quantify the Project emission rates.

3.1 Project Emissions

Table B-1 in Appendix B summarizes the Project-related criteria air pollutant emission rates. As shown on Table B-1, the Project triggers PSD review for GHG, which is under EPA's permitting authority, and for CO, NO_X, PM, PM_{10}, $PM_{2.5}$, and VOC, which are under the TCEQ's permitting authority. Therefore, ETC is submitting separate and concurrent PSD permit applications to EPA and TCEQ.

Detailed GHG emissions calculations are included in Appendix B to this document.

3.2 Emissions Controls (BACT)

The EPA and TCEQ require the application of BACT for the control of each regulated pollutant emitted from new stationary sources. The equipment and activities in this permit application will meet BACT requirements for GHG. Due to the complex BACT analysis required for a PSD application, an entire section (Section 4) is dedicated to presenting BACT for the Project GHG sources.

3.3 Emission Rate Calculation Methodologies

The following subsections briefly describe the methodologies used to estimate the maximum hourly and annual GHG emission rates from the Project's proposed emission sources. Emissions from the Site's sources were estimated using published emission factors and equations in 40 CFR Part 98 Subparts C and W, equipment vendor-provided information, and process simulation software. Detailed emission rate calculations are included as Appendix B to this document, and documentation in support of the calculations has been included in Appendices C and E, as appropriate.

3.3.1 Engines

As part of the Project, ETC will install five natural gas-fired engines per Plant. Annual GHG mass emission rates are estimated by applying the emission factors in Tables C-1 and C-2 of 40 CFR Part 98 Subpart C to the maximum annual heat input and summing the resultant emission rates. These emission factors are:

- CO_2: 53.02 kg/MMBtu
- CH_4: 0.001 kg/MMBtu
- N_2O: 0.0001 kg/MMBtu

The maximum heat input in MMBtu/hr is determined by applying the rated horsepower (HP) of the engine to the fuel consumption rate (Btu/hp-hr) of the engine at 100% load.

The annual CO_2e emission rates are estimated by applying the global warming potential (GWP) of each GHG pollutant to its mass emission rate prior to summing. The GWP for each pollutant is:

- CO_2: 1
- CH_4: 21
- N_2O: 310

Please refer to the combustion-related GHG emission calculation sheet in Appendix B for example calculations.

3.3.2 Heaters

The Project includes the installation of four natural gas-fired heaters per Plant. Annual GHG mass emission rates for the heaters are estimated by applying the emission factors in Tables C-1 and C-2 of 40 CFR Part 98 Subpart C to the maximum annual heat input and summing the resultant emission rates. The maximum annual heat input assumes that the maximum hourly heat input rate occurs 8,760 hr/yr.

The annual CO_2e emission rates are estimated by applying the GWP of each GHG pollutant to its mass emission rate prior to summing.

Please refer to the combustion-related GHG emission calculation sheet in Appendix B for example calculations.

3.3.3 Thermal Oxidizers and Flare

The Project includes the installation of one thermal oxidizer per Plant and one flare for the Site. GHG emissions from the thermal oxidizers and flare result from fuel gas combustion and waste gas combustion.

Annual GHG mass emission rates from fuel gas combustion in the thermal oxidizers and flare are estimated by applying the emission factors in Tables C-1 and C-2 of 40 CFR Part 98 Subpart C to the maximum annual heat input and summing the resultant emission rates. The maximum annual heat inputs from fuel firing assume that the maximum hourly fuel firing rates occur 8,760 hr/yr.

Annual GHG mass emission rates from waste gas combustion in the thermal oxidizers and flare are estimated by summing the following:

- **Un-combusted CO_2:** CO_2 in the waste gas streams that pass through the thermal oxidizers (Amine Unit Waste Gas and TEG Dehy Unit Regeneration Vent) or flare (Compressor Engine Blowdown and Starter Vents):
  - Thermal oxidizers: Amine Unit Waste Gas and TEG Dehy Unit Regeneration Vent CO_2 emissions are calculated using the ProMax v. 3.0 simulation program (PROMAX) as allowed by 40 CFR §98.233(d)(3) and (e)(1), respectively, and
  - Flare: Compressor Engine Blowdown and Starter Vents CO_2 emissions are calculated by applying the CO_2 content of the stream to the total emission rate per 40 CFR §98.233 equation W-20;
- **Combustion CO_2**: CO_2 generated from combustion of the waste gas:
  - Thermal oxidizers: using the waste gas mass flow rate from PROMAX and the number of carbon atoms in the gas stream with a 99% conversion for the thermal oxidizer combustion efficiency and
  - Flare: using the Compressor Engine Blowdown or Starter Vent volumetric flow rate per event, times the annual number of events, and the number of carbon atoms in each gas stream emissions were calculated using 40 CFR §98.233 equation W-21;
- **Un-combusted methane:** the post-control methane emission rate, or that portion that is not combusted in the thermal oxidizers (99% destruction efficiency [DRE]) or flare (98% DRE):
  - Thermal oxidizers: Amine Unit Waste Gas and TEG Dehy Unit Regeneration Vent methane emissions are calculated using PROMAX and a 99% destruction efficiency;
  - Flare: Compressor Engine Blowdown and Starter Vent methane emissions are calculated using 40 CFR §98.233 equation W-19.
- **Combustion N_2O:** N_2O generated from combustion of the waste gas, which is calculated using 40 CFR §98.233 equation W-40:
  - Thermal oxidizers: the waste gas volumetric flow rate from PROMAX times the HHV from PROMAX and
  - Flare: the Compressor Engine Blowdown or Starter Vent volumetric flow rate per event, times the annual number of events, times the HHV of each vent's stream.

The annual CO_2e emission rates are estimated by applying the GWP of each GHG pollutant to its mass emission rate prior to summing.

Please refer to the combustion-related GHG emission calculation sheet and the thermal oxidizers waste gas GHG calculation sheet in Appendix B and the PROMAX simulation results in Appendix E.

3.3.4 Piping Equipment Leaks

Hourly emission rates from equipment leaks are calculated by applying emission factors from the TCEQ draft guidance document, "Air Permit Guidance for Chemical Sources: Equipment Leak Fugitives," dated October 2000 to the number of components. Annual emissions are estimated by assuming the maximum hourly emission rate could occur 8,760 hours per year.

As part of this Project, ETC will be implementing the 28LAER LDAR Program for the entire Project. Control efficiencies, which are listed by equipment type in the TCEQ guidance document, are applied to the emissions as appropriate.

CO_2 and methane emissions are estimated by applying each constituent's concentration in the gas/liquid stream to that stream's total emission rate.

3.4 Emissions Monitoring

In order to demonstrate compliance with the proposed GHG emission rates, ETC proposes to monitor the following parameters and summarize the data on a calendar month basis:

- operating hours for all air emission sources;
- the natural gas fuel usage for all combustion sources, using continuous fuel flow monitors (a group of equipment can utilize a common fuel flow meter, as long as actual fuel usage is allocated to the individual equipment based upon actual operating hours and maximum firing rate); and
- the daily natural gas processing rate for each Plant.

ETC will implement the 28LAER LDAR program, and keep records of the monitoring results, as well as the repair and maintenance records.

At least once a year, ETC will obtain an updated analysis of the inlet gas and residue gas, to document the CO_2 and methane content of the gas streams. This analysis will be considered to be representative of the gas streams for the calendar year during which it was taken and will be used to estimate the Amine Unit Waste Gas and TEG Dehy Unit Regenerator Vent emissions and LHV.

For each calendar month, ETC will estimate the 12-month rolling GHG emission rates for comparison to the Maximum Allowable Emission Rates Table (MAERT).

ETC will also maintain site specific procedures for best/optimum maintenance practices and vendor-recommended operating procedures and O&M manuals.

4 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

The PSD regulation requirements of 40 CFR §52.21(j) require that BACT be used to minimize the emissions of pollutants subject to PSD review from a new major source or a modification to an existing major source. BACT is typically evaluated on a pollutant by pollutant basis and on an emission unit by emission unit basis. This section presents the GHG BACT analysis for the Project.

Section 4.1 provides background information for the BACT analysis. Section 4.2 provides an overview of the BACT review process used in this application. Section 4.3 addresses BACT for GHG emissions.

4.1 Background

The GHG sources associated with the Project are summarized in Table 4-1. As shown on Table 4-1, the Project GHG sources emit GHG by either combustion or by GHG in the process streams, and the GHG is emitted either through stacks or as fugitive emissions.

All refrigeration compressors will be powered by electric gas driven engines. All inlet compressors will be dual-drive engines (with the option of being powered by electricity or natural gas). Because dual-drive technology is not available for the residue compressors' engine model at this time, all residue compressors will have natural gas-driven engines. All combustion sources at the Site will be fired on pipeline-quality natural gas.

ETC will limit start-up operations to 30 minutes for engines, heaters, and reboilers. These limited hours of MSS operation will minimize all pollutants associated with combustion sources.

The overall energy efficiency of the sources through technologies, processes, and practices at the Plant should be included in a BACT determination. In general, a more energy-efficient technology burns less fuel than a less energy efficient technology on a per-unit-of-output basis. Energy efficient technologies in the BACT analysis help reduce the production of combustion-related GHG and other regulated pollutants (CO, NO_X, $PM/PM_{10}/PM_{2.5}$, SO_X, and VOC). Because all the equipment associated with this project is new, it will be outfitted with the best available engineering design and with the latest available technology to ensure the best available energy efficiency for the Plant's intended processes.

TABLE 4-1

PROJECT GHG EMSSION SOURCES

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Equipment Type	GHG Source Type	Exhaust Type
Internal Combustion Engines (> 500 hp, electric-driven and natural gas-fired)	Combustion Source	Stack
Engine Blowdowns (recirculated back to suction/routed to flare)	Process Source	Stack
Engine Starter Vents (routed to flare)	Process Source	Stack
Plant Flare (intermittent MSS control of engine blowdowns and starter vents)	Combustion Source	Stack
Heaters and Reboilers (<100MMBtu/hr, natural gas-fired)	Combustion Source	Stack
Amine Unit Flash Tanks (recirculated back to inlet suction) and Regenerator Waste Gas Vents (routed to Thermal Oxidizer)	Process Source	Stack
TEG Dehydrator Flash Tanks (recirculated back to inlet suction) and Regenerator Vents (routed to Thermal Oxidizer)	Process Source	Stack
Thermal Oxidizer (control of Amine Unit and TEG Dehydration Unit Regenerator Vents)	Combustion Source	Stack
Piping Fugitives	Process Source	Fugitive

4.2 BACT Review Process

EPA recommends that the *1990 Draft New Source Review Workshop Manual* be used to determine BACT for PSD pollutants. According to this document, BACT determinations are made on a case by case basis using a "top-down" approach, with consideration given to technical practicability and economic reasonableness. Section 169(3) of the Clean Air Act defines BACT as follows:

> "The term BACT means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under the Clean Air Act emitted from or which results from any major emitting facility, which the permitting authority, on a case by case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable through application of production processes and available methods, systems, and techniques for control of each such pollutant. In no event shall application of BACT result in emissions of any pollutants which will exceed any applicable standard established pursuant to section 111 (NSPS [New Source Performance Standards]) or 112 (NESHAPS [National Emission Standards for Hazardous Air Pollutants]) of the Clean Air Act."

Specifically the "top-down" approach shall include the following steps:

1. **Identify all available control technologies for a targeted pollutant:**
   The process begins by identifying the available control technologies and techniques on a source-by-source and pollutant-by-pollutant basis. All control options that have a practical potential for application are listed in this step. In order to identify the options, ETC has conducted a search of the EPA's RACT/BACT/LAER Clearinghouse (RBLC), other federal and state air permits and associated inspection/performance test reports, and controls applied to similar sources other than the source category being evaluated. Where applicable, references to a search of the RBLC have been included to illustrate control technologies implemented on similar sources. The RBLC is maintained by EPA and was created to assist applicants in selecting appropriate control technology for new and modified sources. The RBLC was accessed in a query of BACT using process type and pollutant and looking back over the past ten years. Appendix D to this document contains the results of RBLC queries as well as other supporting documentation for these analyses.

   Evaluation of technical feasibility and the energy, economic or environmental impacts, or other costs, are performed in subsequent steps.

2. **Eliminate technically infeasible options:**
   In this step, identified control options are evaluated for technical feasibility using source-specific factors. Demonstration of technical infeasibility for a technology should show that technical difficulties, based on physical, chemical, and engineering principles, prevent the successful use of the control option on the subject emission unit, or that the technology has never been demonstrated to function effectively on an identical or similar emissions unit. If a technology has not been demonstrated, then a careful review is conducted to determine if the technology is both "available" and "applicable."

3. **Rank remaining control technologies:**
   The overall control effectiveness of each remaining control technology is characterized for the pollutant under review. The effectiveness evaluation includes a review of the expected emission rates and expected emission reductions. The control option with the highest effectiveness is the "top" control option. If the top control option is proposed by the permit applicant as BACT, no further evaluation is required. Otherwise, the process moves to Step 4.

4. **Evaluate the most effective control and document results:**
   In this step, if any technically feasible control options are more effective than the proposed BACT option, the more effective options are compared and evaluated against the proposed BACT option. Factors considered in this evaluation include energy, environmental, and economic impacts, as well as other costs of the control options. The evaluation addresses both positive and negative impacts of each control option. An explanation for rejecting any control option that is more effective than the option ultimately selected as BACT is provided.

5. **Select BACT:**
   The most effective remaining control technology is proposed as BACT.

4.3 GHG BACT

This section presents ETC's demonstration that the Project will utilize BACT for GHG.

4.3.1 Relevant Background

The BACT determination, as required, includes the overall energy efficiency through technologies practices and policies of each source type associated with the Project. In general, a more energy efficient technology burns less fuel. Energy efficient technologies in the BACT analysis help reduce the production of GHG and other regulated air pollutants. Because the Project involves the installation of new equipment, all of the equipment should be of the best engineering design and equipped with the latest technology to ensure energy efficiency. In addition, once electrical power is available, ETC will rely on it to power a significant portion of the Plant's compressors.

Performance benchmarking is an available tool that is useful in assessing energy efficiency. There are a number of resources available for benchmarking facilities, including EPA's ENERGY STAR program for industrial sources. ENERGY STAR has developed sector specific benchmarking tools called Energy Performance Indicators (EPI). These energy performance indicators are included in the EPA sponsored document *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Manager* Document Number LBNL-964E, dated June 2008. This tool is especially useful for GHG because the traditional method of collecting information, such as the RBLC, has yet to be populated with updated case-specific GHG information due to the infancy of the program. Although EPI does not specifically address natural gas processing or natural gas compressor stations, ETC utilized this tool to identify methods and the associated efficiency that can be achieved for similar sources (natural gas combustion devices).

ETC also reviewed the EPA's Sector GHG control white papers for petroleum refineries, natural gas combustion, and biomass energy. These papers were prepared by the Sector Policies and Programs Division, Office of Air Quality Planning and Standards. These documents address sources that are significantly different than those associated with the Project. A sector paper on natural gas processing plants or natural gas compressor stations is not currently available.

When performing a "top-down" BACT analysis, an applicant is required to review control technologies for similar sources. These sources have been identified as the most similar and available to those associated with the Project.

The only control methods identified for control of GHG (including CO_2, N_2O and CH_4) are to limit GHG production using good combustion practices and to implement carbon capture and storage (CCS). Because there is very limited data available on GHG controls due to the newness of the program, ETC ran a search for GHG from all emissions sources found in the RBLC in an effort to identify all available control methods.

The best way to control combustion-related GHG and other regulated pollutants is through thermal efficiency achieved through design and operation. Good combustion practices are considered BACT for all the combustion sources and pollutants associated with the Project.

These practices are based on EPA guidance located at http://www.epa.gov/ttnatw01/iccr/dirss/gcp.pdf (included in Appendix D to this document) and are summarized in Table 4-2. This table serves as the BACT discussion for all combustion sources proposed with the Project. ETC will apply all these practices and standards to each combustion source associated with the Project, unless otherwise noted.

4.3.2 GHG Emissions Source Categories

The majority of the contribution of GHGs associated with the Project is from combustion sources (i.e., engines, reboilers, heaters, flare, and thermal oxidizers) and the Amine Units. The TEG Dehydration Units and piping component leaks (i.e., fugitive emissions) contribute a minor amount of GHG. Stationary combustion sources primarily emit CO_2, and a small amount of N_2O and CH_4.

This GHG BACT discussion is divided into two categories: stack GHG (including process-related and combustion-related GHG) and fugitive GHG.

4.3.2.1 Stack GHG

The Stack GHG sources emit the vast majority of the Site's GHG. The stack GHG emissions include process-related GHG (i.e., due to CO_2 and methane in the process and waste streams) and combustion-related GHG (i.e., due to the combustion of fuel gas and waste gas streams).

TABLE 4-2

SUMMARY OF GOOD COMBUSTION PRACTICES

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Good Combustion Technique	Practice	Standard
Operator practices	Official documented operating procedures, updated as required for equipment or practice change	Maintain written site specific operating procedures in accordance with Good Combustion Practices (GCPs), including startup, shutdown, and malfunction
	Procedures include startup, shutdown, malfunction	
	Operating logs/record keeping	
Maintenance knowledge	Training on applicable equipment and procedures	Equipment maintained by personnel with training specific to equipment
Maintenance practices	Official documented maintenance procedures, updated as required for equipment or practice change	Maintain site specific procedures for best/optimum maintenance practices
	Routinely scheduled evaluation, inspection, overhaul as appropriate for equipment involved	Scheduled periodic evaluation, inspection, overhaul as appropriate
	Follow vendor recommendation	
	Maintenance logs/record keeping	
Fuel quality (analysis); Use of clean fuels (natural gas)	Monitor fuel quality	Fuel analysis where composition could vary and where of significance to sulfur content
	Periodic fuel sampling and analysis	
	ETC shall use only pipeline quality natural gas. Natural gas burns more cleanly than fuels with higher hydrocarbon content.	
Combustion air distribution	Adjustment of air distribution system based on visual observations	Routine and periodic adjustments and checks
	Adjustment of air distribution based on continuous or periodic monitoring	
Good engineering design	Since the plant is a new construction, all sources shall be operating at the best efficiency possible by design.	Keep record of manufacturer's certificate and maintain the engines as per the manufacturer's guidelines.
Conducting visible emissions observations	Visible emissions observations shall be made and recorded in accordance with the requirements specified in 40 CFR §64.7(c).	Maintain schedule and records of the visible emission observation made.

Process-Related Stack GHG

The Amine Units and TEG Dehydration Units emit process-related stack GHG. As discussed previously, the Amine Units' primary function is to remove CO_2 from the natural gas. As part of the process, a small amount of hydrocarbons (including methane) can become entrained in the amine. When the amine is regenerated, these GHG are emitted in the waste gas. That is, the Amine Unit waste gas contains CO_2 and methane, which are process-related GHG emissions.

Also as described previously, the TEG Dehydration Units remove water from the gas. As part of the process, a small amount of gas (containing CO_2 and methane) can become entrained in the TEG. When the TEG is regenerated, the resultant waste gas stream contains CO_2 and methane. Therefore, the TEG Dehydration Unit Regenerator Vents, which result in process-related GHG emissions.

The compressor engine blowdowns and starter vents emit MSS-related GHG, due to CO_2 and methane contained in the inlet gas and residue/fuel gas streams.

Combustion-Related Stack GHG

The refrigeration compressor engines at the Site will be powered by electricity, so they will not emit GHG. The inlet compressors will be equipped with dual-drive engines (with the option of being powered by electricity or natural gas). The residue compressors will be equipped with natural gas-fired engines. All gas-fired engines will be lean burn with low NO_X technology, and they will be operated using good combustion practices.

The heaters at the Site will be fired on pipeline-quality natural gas. These heaters are all rated at < 50 MMBtu/hr. The heaters will be equipped with next generation ultra-low-NO_X burners (NGULNB), and they will have burner management systems. Specifically, the heaters will be equipped with Low-NO_X staged/quenching (flue gas recirculating) burners capable of meeting 0.036 lb-NO_X/MMBtu with additional excess O_2 (i.e., requiring a larger combustion air blower). The heaters are tuned for thermal efficiency.

As stated previously, emissions from each plant's Amine Unit Regenerator Vent and each TEG Dehydration Unit Regenerator Vent are routed to a thermal oxidizer for control of H_2S and VOC in the exhaust streams. The process-related CO_2 emissions from each Amine Unit and TEG Dehydration Unit will flow through the thermal oxidizers to atmosphere, and the hydrocarbon emissions, including methane, will be oxidized to form combustion-related GHG. The oxidizers have a 99% DRE for hydrocarbon compounds, so 1% of the methane will pass through the oxidizers uncombusted, as process-related GHG. In addition, the oxidizers will fire pipeline quality natural gas (i.e., generating combustion-related GHG), at maximum rate of 7 MMBtu/hr, as needed to maintain a combustion chamber temperature of 1,400 °F.

An intermittent Plant Flare will be utilized to control emissions associated with compressor/engine blowdowns and starter vents, generating combustion-related GHG. The Plant Flare has a 98% DRE, so

2% of the methane in the blowdown and starter vents will pass through the flare as process-related GHG. The flare also combusts pipeline quality natural gas through its pilot, which has a firing rate of 0.1 MMBtu/hr, generating a small amount of combustion-related GHG.

Please note the flare is not a continuous process flare, but an intermittent use MSS flare. It controls compressor engine blowdowns (shutdown) and engine starter vents (startup). Therefore, no continuous stream other than pilot gas is being combusted.

The GHG emissions from combustion sources can be reduced by operating with thermal efficiency/good combustion practices. The Stack GHG emissions are able to be captured, so Carbon Capture and Storage (CCS) is an option for consideration. CCS is an emerging "end of the pipe" add-on control technology comprised of three stages (capture/compression, transport, and storage).

4.3.2.2 Fugitives

A small amount of GHG may be emitted via piping equipment leaks (i.e., due to CO_2 and methane in the gas streams). It is infeasible to capture GHG emissions from fugitive sources such as piping leaks. Therefore, CCS is not an add-on control technology that has a potential for application and it is not identified as a feasible technology for controlling fugitives. However, fugitive GHG emissions can be reduced by utilizing a leak detection and repair (LDAR) program. There are many structured LDAR programs that have been developed as part of state and federal rulemaking and BACT. ETC has evaluated the existing programs for the purpose of this BACT analysis.

4.3.3 Stack GHG BACT

The following paragraphs present ETC's evaluation of BACT for stack GHG emissions.

4.3.3.1 Step 1 | Identify All Available Control Technologies

ETC has identified the following potentially applicable control technologies for controlling process-related and combustion-related stack GHG emissions associated with the Project:

All Stack GHG

- Carbon Capture and Transport and/or Storage (CCS) as add-on control.

Process-Related Stack GHG Only

Because the Amine Units are designed to remove CO_2 from the natural gas, the generation of CO_2 (GHG) is inherent to the process, and a reduction of CO_2 emissions by process changes would only be achieved by a reduction in the process efficiency, which would result in natural gas that would not meet pipeline quality specifications and leave CO_2 in the natural gas for emission to the atmosphere at downstream sources. The Amine Units do emit methane (GHG) at the point of amine regeneration, due to a small amount of natural gas becoming entrained in the rich amine.

The TEG Dehydration Units are located downstream of the Amine Units, so that the vast majority of the CO_2 entrained in the natural gas has already been removed. But similar to the Amine Units, the TEG Dehydration Units do emit CO_2 and methane at the point of regeneration due to natural gas becoming entrained in the rich glycol.

The compressor engine blowdowns and starter vents emit MSS-related GHG, due to CO_2 and methane contained in the inlet gas and residue/fuel gas streams.

The methods to reduce process-related GHG include:

- Proper Design and Operation: The Amine Units and TEG Dehydration Units are each designed to include a flash tank, in which gases (i.e., including CO_2 and methane) are removed from the rich amine or rich glycol stream prior to regeneration, thereby reducing the amount of waste gas created. ETC will construct and operate the Amine Units and TEG Dehydration for optimal performance;
- Install Amine Unit and TEG Dehydration Unit Flash Tank Offgas Recovery Systems: The Amine Unit and TEG Dehydration Unit flash tank offgases will all be recycled back into each Plant for reprocessing, instead of venting to atmosphere or combustion device;
- Routing Amine and TEG Dehydration Unit Regenerator Vents to a Thermal Oxidizer: This control device will reduce the methane emissions by 99% and will convert those emissions to CO_2, which has a lower GWP;
- Routing Amine and TEG Dehydration Unit Regenerator Vents to a Flare: This control device will reduce the methane emissions by 98% and will convert those emissions to CO_2, which has a lower GWP;
- Routing Compressor Engine Blowdown and Starter Vents to a Thermal Oxidizer: This control device will reduce the methane emissions by 99% and will convert those emissions to CO_2, which has a lower GWP.
- Routing Compressor Engine Blowdown and Starter Vents to a Flare: This control device will reduce the methane emissions by 98% and will convert those emissions to CO_2, which has a lower GWP.
- Install Blowdown Gas Recovery System: blowdowns due to engine shutdowns will be routed back into suction as much as possible (i.e., depending upon the pressures, suction, and specific parameters specific to each shutdown) to recover the gas down to a minimum pressure and minimize the volume sent to flare.

<u>Combustion-Related Stack GHG Only</u>

The methods to reduce combustion-related GHG include:

- Fuel Selection/Switching: ETC will be firing only pipeline quality natural gas, which results in 28% less CO_2 production than fuel oils (see 40 CFR Part 98, Subpart C, Table C-1, which is included in Appendix E, for a comparison of the GHG emitting potential of various fuel types);

- Use of electric-driven engines and limits on gas-fired operations (i.e., dual-drive engines), where technically feasible: The refrigeration compressors will be electric-driven, resulting in no GHG emissions from these sources. The inlet compressors will be dual-drive, with gas-fired operations limited to a Site-wide annual limit of 28,000 hours (based upon an average of 3,500 hr/yr each), which will result in a 60% reduction in annual GHG emissions. Dual-drive technology is not available (or technically feasible) for the residue compressor engines, so they will be gas-fired;
- Efficient engine, heater, and burner design: New burner design improves the mixing of fuel, creating a more efficient heat transfer. Because this is a new facility, new burners will be utilized. ETC will utilize burner management systems on the heaters, such that intelligent flame ignition, flame intensity controls, and flue gas recirculation optimize the efficiency of the devices.
- Periodic tune-ups and maintenance for optimal thermal efficiency: Periodic tune-ups will increase the efficiency of the engines. Maintenance will be performed routinely per vendor recommendations or the facility's maintenance plan, and replacing or servicing components will be performed as needed. ETC will tune the heaters and engines once a year for optimal thermal efficiency;
- Fuel gas pre-heating: Preheating the fuel stream reduces the heating load, increases thermal efficiency and therefore reduces emissions. However, this technology is more relevant to large boilers (>100 MMBtu/hr). ETC will not be preheating the fuel stream for the compressor engines, because the engines are designed for lower fuel and inlet air temperatures for efficient compression ignition. ETC will not be preheating the natural gas for the heaters due to their size (< 100 MMBtu/hr) and because more efficient options are available, as described below in Step 4;
- Oxygen trim control: Combustion devices operate with a certain amount of excess air to reduce emissions and for safety consideration. An inappropriate mixture may lead to inefficient combustion. The gas-fired compressor engines will be equipped with oxygen trim control as part of their ultra-lean-burn design. Regular maintenance of the draft air intake systems of the engines and heaters can reduce energy usage. Draft control is applicable to new or existing process heaters and is cost effective for process heaters rated at 20 to 30 MMBtu/hr or greater. The heaters will have air and fuel valves mechanically linked to maintain the proper air to fuel ratio;
- Heat Recovery: The hot effluent from the hot oil heaters is cooled in the primary and secondary heat exchangers that heat the hot oil (heat transfer medium for the Site) to recover this energy and reduce the overall energy use in the plants. Tertiary exchangers also recover heat and contribute to overall energy efficiency. Finally, the combustion convective section is used to pre-heat the hot oil to the extent that the final exiting flue gas temperature is reduced to its practical limit;
- Air/fuel ratio controllers: Air/fuel ratio controllers minimize methane emissions from reciprocating engines. Oxygen monitors and intake flow monitors can be used to optimize the fuel/air mixture and limit excess air and reduce the amount of energy required to heat the stream and, therefore, reduce the CO_2e emissions. Please note because these engines are equipped with the ultra-lean burn technology, air/fuel ratio controllers are inherent to the process in the engines. As stated previously, the heaters' air and fuel valves will be mechanically linked to maintain the proper air to fuel ratio;
- Burner management systems: The heaters will be equipped with burner management systems, that will include intelligent flame ignition, flame intensity controls, and flue gas recirculation;

- Energy efficiency: High efficiency motors and variable speed drives reduce electricity consumption by 4 – 17% when compared to standard motors and fixed speed drives;
- Limit of start-up operations to 30 minutes for engines, heaters, and reboilers;
- Proper flare operation: Poor flare combustion efficiencies lead to higher methane emissions and higher overall GHG emissions. Poor combustion efficiencies can occur at very low flare rates, very high flowrates (i.e., high flare exit velocities), and when flaring gas with low heat content and excessive steam to gas mass flows. ETC will only be flaring high Btu gases, will monitor the Btu content on the flared gas, and will have air assisted combustion allowing for improved flare gas combustion control and minimizing periods of poor combustion. Please note the flare is not a process flare, but an intermittent use MSS flare. It controls blowdowns (shutdown) and starter vents (startup). Therefore, no continuous stream (other than pilot gas) is being combusted, and add on controls are not technically feasible. Periodic maintenance will help maintain the efficiency of the Flare. The Flare will also be operated in accordance with 40 CFR §60.18, including heating value and exit velocity requirements, as well as pilot flame monitoring; and
- Proper thermal oxidizer operation: Periodic maintenance will help maintain the efficiency of the thermal oxidizer. Temperature monitoring will ensure proper thermal oxidizer operation.

4.3.3.2 Step 2 | Eliminate Technically Infeasible Options

ETC considers all identified options listed in Section 4.3.3.1 to be technically feasible, except for the following option:

Routing Compressor Engine Blowdown and Starter Vents to a Thermal Oxidizer: Not Feasible

A thermal oxidizer is not considered a technically feasible control device for the control of compressor engine starter emissions, because they are intermittent MSS events, and there is a very wide range of flow rates, depending upon the startup and shutdown schedule of the engines/compressors. The oxidizer would have to be designed for maximum MSS flow rates, and it would have to combust fuel gas (i.e., generating additional combustion-related emissions, including GHG) during the majority of the time when MSS emissions are not occurring at the maximum flow rate. A flare is the only technically feasible option for control of an intermittent stream of varying flow.

4.3.3.3 STEP 3 | Rank Remaining Control Technologies

Because thermal efficiencies are work practice standards, it is difficult to identify discriminate control efficiencies for ranking. ETC used *Available and Emerging Technology for Reducing Greenhouse Gas Emission from the Petroleum Industry* dated October 2010 and *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Manager,* Document Number LBNL-964E, dated June 2008, to identify any available control efficiencies. The efficiency improvement/GHG reduction technologies are ranked below. The technologies that ETC will be implementing are in bold-face type.

- **Use of electric-driven engines (100%, when powered by electricity);**
- **Install Amine Unit and TEG Dehydration Unit flash tank offgas recovery systems (100%);**
- **Routing the Amine Unit and TEG Dehydration Unit regenerator vents to a thermal oxidizer (99% for methane, generates CO_2);**
- Routing the Amine Unit and TEG Dehydration Unit regenerator vents to a flare (98% for methane, generates CO_2);
- **Control of engine starter vents by the flare (98% for methane, generates CO_2);**
- **Installation of compressor blowdown recovery system, and routing remaining blowdown gas to the flare (98% for methane, generates CO_2);**
- **Use of dual-drive engines when technically available and establishment of federally-enforceable limits on gas-fired operations (28,000 hr/yr for 8 engines combined, which is based upon an average of 3,500 hr/yr each) (60%);**
- **Fuel selection/switching (28% when comparing natural gas and No. 2 Fuel Oil);**
- **Burner management systems on the heaters, with intelligent flame ignition, flame intensity controls, and flue gas recirculation (10-25%);**
- **Air/fuel ratio controllers associated with lean burn engines (5-25%);**
- **Efficient engine/heater and burner design (10%);**
- **Energy efficiency (4-17% of electricity consumption) using high efficiency motors, variable speed drives);**
- Preheating fuel stream (10-15%);
- **Proper flare and thermal oxidizer operation (1-15%);**
- **Annual tune-ups and maintenance (1-10%);**
- **Oxygen trim control associated with lean burn engines (1-3%);**
- **Limit of start-up operations to 30 minutes for engines, heaters, and reboilers; and**
- CCS (not a feasible option for the Project due to technical, environmental, and economic reasons, as discussed in Step 4).

Table 4-3 lists these technologies and the source of the estimated GHG control efficiencies.

4.3.3.4 STEP 4 | Evaluate the Remaining Control Efficiencies

ETC is implementing the top ranked BACT for Stack GHG. Of the technologies listed in Step 3, only three options are not proposed to be implemented as part of the Project. First, ETC will not be routing the Amine Unit and TEG Dehydration Unit regenerator vents to a flare (98% control), because a more efficient technology (thermal oxidizer, with 99% efficiency) is being used. Second, ETC will not be preheating the fuel, because the burner management systems, which include flue gas recirculation, achieve a higher overall combustion efficiency. Finally, CCS is not considered by ETC to be feasible, based upon its lack of readily available technologies and negative environmental impacts, as well as its negative economic impacts. However, per EPA guidance, EPA has identified CCS as an add-on control technology that is available for the Stack GHG that must be evaluated as if it were technically feasible.

TABLE 4-3
GHG CONTROL TECHNOLOGY RANKING FOR BACT STEP 3
AIR PERMIT APPLICATION
JACKSON COUNTY GAS PLANT
ETC TEXAS PIPELINE, LTD.

Control Technology	Estimated GHG Percent Reduction	Source of Percent Reduction Determination	Proposed as BACT?
Electric-Driven Engines	100	Based upon only using electricity so no combusted related GHG emissions	Yes
Amine Unit and TEG Dehydration Unit flash tank offgas recovery systems	100	Hard piped back into the system	Yes
Amine Unit and TEG Dehydration Unit regenerator vents to thermal oxidizer	99	Vendor Data	Yes
Amine Unit and TEG Dehydration Unit regenerator vents t	98	http://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/flares/	No
Compressor Engine Starter Vents to flare	98	http://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/flares/	Yes
Compressor Engine Blowdown Vents to flare	98	http://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/flares/	Yes
Dual drive engines (limited operation 28,000 hours/yr for 8	60	Based upon 3,500 hours out 8,760 hours per year (equates to 60% of year)	Yes
Fuel selection/switching (natural gas versus No. 2 Fuel Oil	28	40 CFR Part 98 Subpart C, Table C-1	Yes
Burner management systems	10-25	*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr* y issued by EPA October 2010 Section 5.1.2.1 Draft Control and Vendor Data	Yes
Air/Fuel ratio controller with lean burn engines	5-25	*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr* y issued by EPA October 2010 Section 5.1.2.1 Draft Control	Yes
Efficient engine/heater burner design	10	*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr* y issued by EPA October 2010 Section 3.0 Summary of GHG Reduction Measures Table 1 Summary of GHG Reduction Measures for the Petroleum Refinery Industry	Yes
High efficiency motors	4-17	*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr* y issued by EPA October 2010 Section 3.0 Summary of GHG Reduction Measures Table 1 Summary of GHG Reduction Measures for the Petroleum Refinery Industry	Yes
Preheating fuel stream	10-15	*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr* y issued by EPA October 2010 Section 5.1.2.2 Air Preheating and Table 1 Summary of GHG Reduction Measures for the Petroleum Refinery Industry	No
Proper flare and thermal oxidizer operation	1-15	*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr* y issued by EPA October 2010 Section 3.0 Summary of GHG Reduction Measures Table 1 Summary of GHG Reduction Measures for the Petroleum Refinery Industry	Yes
Annual tune-ups and maintenance	1-10	*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr* y issued by EPA October 2010 Section 5.1.1.5 Improved Maintenance	Yes
Oxygen trim control (lean burn engines)	1-3	*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr* y issued by EPA October 2010 Section 3.0 Summary of GHG Reduction Measures Table 1 Summary of GHG Reduction Measures for the Petroleum Refinery Industry	Yes
Limit start up operation to 30 minutes for engine, heaters and reboilers	N/A	N/A	Yes
CCS	80	*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr* y issued by EPA October 2010 Section 5.1.4 Carbon Capture. Also noted that industrial application of this technology is not expected to be available for 10 years.	No

The emerging CCS technology is an "end of pipe" add-on control method comprised of three stages (capture/compression, transport, and storage). CCS involves separation and capture of CO_2 from the exhaust gas, pressurization of the captured CO_2, transmission of CO_2 via pipeline, and injection and long term geologic storage of the captured CO_2. Several different technologies are at varying stages of development, some at the slip stream or pilot scale while many others are still at the bench top or laboratory stage of development.

The use of CCS on the Stack GHG emissions is not technically or environmentally feasible for the Site. The goal of CO_2 capture is to concentrate the CO_2 stream from an emitting source for transport and injection at a storage site. CCS requires a highly concentrated, pure CO_2 stream for practical and economic reasons. Extracting CO_2 from exhaust gases requires equipment to capture the flue gas exhaust and to separate and pressurize the CO_2 for transportation.

The stack vent streams will be low pressure, high volume streams at a very high temperature, with low CO_2 content and will contain miscellaneous pollutants, such as PM that can contaminate the separation process. Table 4-4 summarizes the stack parameters and CO_2 content of the streams.

The CO_2 separation would first require the removal of PM from the streams without creating too much back pressure on the upstream system (i.e., the Plants' combustion processes). Next, it would require inlet compression to increase the pressure from atmospheric to the minimum of 700 pounds per square inch (psi) required for efficient CO_2 separation. The installation of additional cryogenic units or other cooling mechanisms (e.g., complex heat exchangers) would be required to reduce the temperature of the streams from over 800 °F to less than 100 °F prior to separation, compression, and transmission. Also, the installation of additional amine units to capture the CO_2 from the streams would be required. The cryogenic units would each require propane compression, similar to the currently-proposed cryogenic units. Finally, the separated CO_2 stream would require large compression equipment to pressurize the CO_2 to transfer to the Denbury pipeline. The inlet and CO_2 compressors must be designed to handle acidic gases, with high energy consumption/cost to compress the gas to processing and transport requirements.

Moreover, because the electricity required to run additional compressors is not available at the Site, additional natural gas-fired engines for propane refrigeration would be required, and additional natural gas-fired engines for CO_2 compression would be required. Therefore, the fuel consumption and resultant combustion-related GHG emissions would be even greater.

The processes required to separate and compress CO_2 are already implemented at the Site. In fact, the majority of the Site's CO_2 emissions are from the Amine Units that remove CO_2 from the inlet gas, which is 1.96 mol% CO_2, flowing at 200 MMscfd, or 73,000 MMscf/yr per plant, for a Site-wide total of 292,000 MMscf/yr.

The combined volumetric flow of the Stack GHG is 162,744 MMscf/yr, and the CO_2 content of the combined Stack GHG exhaust stream is 7.14 mol%. To process this stream for CCS, the Site would need to have additional amine units, cryogenic units, dehydration units, and associated equipment (i.e., heaters, tanks, compressor engines, and piping) greater than the size of the proposed Plants 1 and 2 combined.

TABLE 4-4
STACK GHG EXHAUST PARAMETERS AND CO_2 CONTENT
AIR PERMIT APPLICATION
JACKSON COUNTY GAS PLANT
ETC TEXAS PIPELINE, LTD.

Combustion Source EPN	CO_2[a] (T/yr)	CO_2[b] (MMscf/yr)	Stack Diameter[c] (ft)	Exit Velocity[c] (fps)	Temp.[c] (°F)	Total Exhaust[d] (MMscf/yr)	Percent CO_2[e] (vol%)
C-1100A/B, C-2100A/B, C-3100A/B, & C-4100A/B	21,944.53	384.03	2.0	62.1	800	8,237.73	4.66%
C-1121A	18,195.38	318.42	2.5	101.3	800	6,568.88	4.85%
C-1121B	18,195.38	318.42	2.5	101.3	800	6,568.88	4.85%
C-1121C	18,195.38	318.42	2.5	101.3	800	6,568.88	4.85%
C-2121A	18,195.38	318.42	2.5	101.3	800	6,568.88	4.85%
C-2121B	18,195.38	318.42	2.5	101.3	800	6,568.88	4.85%
C-2121C	18,195.38	318.42	2.5	101.3	800	6,568.88	4.85%
C-3121A	18,195.38	318.42	2.5	101.3	800	6,568.88	4.85%
C-3121B	18,195.38	318.42	2.5	101.3	800	6,568.88	4.85%
C-3121C	18,195.38	318.42	2.5	101.3	800	6,568.88	4.85%
C-4121A	18,195.38	318.42	2.5	101.3	800	6,568.88	4.85%
C-4121B	18,195.38	318.42	2.5	101.3	800	6,568.88	4.85%
C-4121C	18,195.38	318.42	2.5	101.3	800	6,568.88	4.85%
H-1706	24,804.90	434.09	3.0	77.1	775	7,345.22	5.91%
H-7810	8,908.26	155.89	3.0	18.5	850	1,661.54	9.38%
H-7820	4,966.10	86.91	2.5	18.5	850	1,153.85	7.53%
H-7410	1,535.91	26.88	1.0	27.6	800	286.36	9.39%
H-2706	24,804.90	434.09	3.0	77.1	775	7,345.22	5.91%
H-7811	8,908.26	155.89	3.0	18.5	850	1,661.54	9.38%
H-7821	4,966.10	86.91	2.5	18.5	850	1,153.85	7.53%
H-7411	1,535.91	26.88	1.0	27.6	800	286.36	9.39%
H-3706	24,804.90	434.09	3.0	77.1	775	7,345.22	5.91%
H-7812	8,908.26	155.89	3.0	18.5	850	1,661.54	9.38%
H-7822	4,966.10	86.91	2.5	18.5	850	1,153.85	7.53%
H-7412	1,535.91	26.88	1.0	27.6	800	286.36	9.39%
H-4706	24,804.90	434.09	3.0	77.1	775	7,345.22	5.91%
H-7813	8,908.26	155.89	3.0	18.5	850	1,661.54	9.38%
H-7823	4,966.10	86.91	2.5	18.5	850	1,153.85	7.53%
H-7413	1,535.91	26.88	1.0	27.6	800	286.36	9.39%
TO-1	69,986.91	1,224.77	3.0	150.4	1,400	9,512.91	12.87%
TO-2	69,986.91	1,224.77	3.0	150.4	1,400	9,512.91	12.87%
TO-3	69,986.91	1,224.77	3.0	150.4	1,400	9,512.91	12.87%
TO-4	69,986.91	1,224.77	3.0	150.4	1,400	9,512.91	12.87%
FS-800	3,227.22	56.48	3.0	Varies	1,000	455.84	12.39%
Totals/Average:	**684,324.58**	**11,975.68**			**936**	**167,359.69**	**7.16%**

[a] Please see Appendix B for the calculation of CO_2 emissions from these sources.

[b] The CO_2 volumetric flow rate is calculated as follows (example is for C-1121A):

(18,195.38 T/yr CO2) * (2,000 lb/T) / (44 lb/lb-mole CO2) * (385 scf/lb-mole) / (10^6/MM) = 318.42 MMscf/yr CO2

[c] This value was taken from the Table1(a), which is located in Appendix A.

[d] The Total Exhaust volumetric flow rate is calculated as follows (example is for C-1121A):

(101.3 fps) * (3,600 s/hr) * (PI * (2.5/2 ft)^2) * (459.67+68 °F) / (459.67+800 °F) * (8,760 hr/yr) / (10^6/MM) = 6,568.88 MMscf/yr

[e] Percent CO_2 is calculated as follows (example is for C-1121A):

(318.42 MMscf/yr CO2) / (6,568.88 MMscf/yr exhaust) * (100%) = 4.85%

For inlet compression, ETC estimates that eight (8) Caterpillar 3616 engines would be needed. For refrigeration compression, ETC estimates that six (6) Caterpillar 3516 engines would be needed. And for CO_2 compression, ETC estimates that one (1) Caterpillar 3606 engine would be needed.

Considering the additional equipment and associated emission sources, implementing CCS at the Site would generate additional GHG greater than the major source threshold (100,000 T/yr) and additional $PM_{10}/PM_{2.5}$ and VOC emissions greater than PSD significance thresholds. A calculation of the emissions from these engines is included in Appendix D, and the totals are:

- CO: 30.48 T/yr
- NO_X: 13.37 T/yr
- $PM_{10}/PM_{2.5}$: 15.81 T/yr
- SO_2: 0.19 T/yr
- VOC: 49.53 T/yr
- GHG: 184,995.37 T/yr

Therefore, ETC believes that CCS is not BACT due to its negative environmental and energy impacts.

There are several on-going CCS projects, ranging in cost from $300 million to $2.6 billion that are heavily funded by the US Department of Energy (DOE) and the Canadian Government. These projects are mostly at coal fired utilities and are small in scale (i.e., only involving a slip stream or are still in the laboratory stage of development). Note that slip stream processing does not enable the evaluation of back pressure studies.

According to the guidance documents for GHG permitting and for reducing carbon dioxide emissions from bioenergy, EPA has concluded that although CCS is available it does not necessarily mean it would be selected as BACT due to its technical and economic infeasibility. In addition, EPA supports the conclusion of the Interagency Task Force on Carbon Capture that although current technologies could be used to capture CO_2 from new and existing plants, they are not ready for widespread implementation. This conclusion is primarily because the technologies have not been demonstrated at the scale necessary to establish confidence in their operations.

Based upon on the issues identified above, ETC does not consider CCS to be a technically, economically, or commercially viable control option for the Site's stack GHG.

Finally, assuming that CCS were readily available and could be implemented on a large-scale basis without negative environmental impact, ETC would still have to resolve several logistical issues including obtaining right of way (ROW) for the pipeline and finding a storage facility or other operation that would be available to receive and handle a large volume of CO_2.

The nearest identified pipeline that may transport CO_2 is approximately 60 miles from the Plant. This pipeline is owned and operated by a direct competitor to ETC, so it would not be a viable option for transport of CO_2. However, Denbury has announced recently the intent to install a pipeline system to receive CO_2 in the next few years. This future pipeline is currently shown to terminate in Alvin, Texas, which is over 120 miles from the Plant. For the purpose of this BACT analysis, ETC has assumed that the Denbury pipeline is the nearest available CO_2 pipeline.

The National Energy Technology Laboratory (NETL) is part of DOE's national laboratory system and is owned and operated by DOE. NETL supports DOE's mission to advance the national, economic, and energy security of the United States. ETC utilized the March 2010 NETL Document *Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447* to estimate the cost associated with the pipeline and associated equipment. This document provides a best estimate of transport storage and monitoring costs for a "typical" sequestration project. CO_2 transport costs are broken down into three categories, as follows:

- **Pipeline/Transfer Costs -** Pipeline costs are derived from the Oil and Gas Journal's annual Pipeline Economics Report for natural gas, oil, and petroleum projects which are expected to be analogous of the cost of building a CO_2 pipeline. The cost estimate includes pipeline materials, direct labor, indirect costs, and right of way acquisition as a function pipeline length and diameter and is based upon a study completed by the University of California.

- **Related Capital Expenditures** – Capital costs associated with CCS are estimated based upon the DOE/NETL study, *Carbon Dioxide Sequestration in Saline Formation* – Engineering and Economic Assessment for typical costs associated with pipeline. The costs were adjusted to include a CO_2 surge tank and pipeline control system. Miscellaneous costs also include surveying, engineering, supervision, contingencies, allowance, overhead, and filing fees.

- **O&M Costs** – O&M costs are based on the DOE/NETL report *Economic Evaluation of CO_2 Storage and Sink Enhancement Option* on a cost/pipeline length basis.

To estimate costs for the Project, ETC utilized the following parameters and the March 2010 NETL document *Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs* DOE/NETL-2010/144.

Because the cost of transport and storage of the Stack GHG emissions would be higher than the cost of just transport, ETC is conservatively (i.e., estimating costs on the low side) assuming that the Denbury pipeline would be a viable recipient of the CO_2 emissions and, therefore, addressing the transportation costs only. Assuming that Denbury would be able to receive the CO_2 stream, the estimated cost associated with transport of the Amine Vent CO_2 to the Denbury pipeline is well over $300MM, or $80.80/T of CO_2 removed. Table 4-5 presents a conservative (i.e., tending to underestimate the cost) cost determination. The cost estimate does not include certain costs that would be required, as described in the following paragraphs.

TABLE 4-5

ESTIMATED COSTS FOR CCS OF STACK CO_2 EMISSIONS

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

CO_2 Pipeline Data

Pipeline Length	120	miles
Pipeline Diameter	8	inches
Number of Injection Wells	0	
Depth of well	N/A	feet
	N/A	meters

CCS Cost Breakdown

Cost Type	Units	Cost		
Pipeline Costs				
Pipeline Materials	$ Diameter (inches), Length (miles)	$64,632 + $1.85 x L x (330.5 x D^2 + 686.7 x D + 26,920)	$	11,965,075.20
Pipeline Labor	$ Diameter (inches), Length (miles)	$341,627 + $1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013)	$	46,644,122.60
Pipeline Miscellaneous	$ Diameter (inches), Length (miles)	$150,166 + $1.58 x L x (8,417 x D + 7,234)	$	14,288,638.00
Pipeline Right of Way	$ Diameter (inches), Length (miles)	$48,037 + $1.20 x L x (577 x D +29,788)	$	5,002,213.00
Other Capital				
Refrigeration Compression(6- CAT 351	$	$9,000,000	$	9,000,000.00
Inlet Compressions (8- Cat 3616)	$	$24,800,000	$	24,800,000.00
CO_2 Compression Equipment	$	$2,000,000	$	2,000,000.00
Cryogenic Units/Amine Units /Dehydra	$	$200,000,000	$	200,000,000.00
CO_2 Surge Tank	$	$3,451,908	$	3,451,908.00
Pipeline Control System	$	$331,896	$	331,896.00
O&M				
Fixed O&M	$/mile/year	$8,632	$	1,003,440.00
		Total Pipeline Cost	**$**	**318,487,292.80**

Amoritized CCS Cost

Total Capital Investment (TCI) =			**$**	**317,483,852.80**
Capital recovery factor (CRF) [1] = $i(1+i)^n/((1+i)^n - 1)$			$	0.15
i = interest rate =	0.08			
n = equipment life =	10	years		
		Amortized installation costs = CRF * TCI =		**$47,314,456.25**
		Total CCS Annualized Cost		**$48,317,896.25**

NOTE: This cost estimate sheet does not include O&M costs associated with the compression equipment or processing equipment.

Amoritized Project Cost (without CCS)

Total Capital Investment (TCI), based upon current AFE =			**$**	**395,000,000.00**
Capital recovery factor (CRF) [1] = $i(1+i)^n/((1+i)^n - 1)$			$	0.10
i = interest rate =	0.08			
n = equipment life =	20	years		
		Amortized installation costs = CRF * TCI =		**$40,231,622.49**
		Total Project Annualized Cost		**$40,231,622.49**

NOTE: Plant lifetime estimated at 20 years, due to normal plant lifetime expectations. However, CCS equipment life anticipated to be 10 years based upon extreme acidic conditions of CO_2 stream.

It should be noted that liability costs are not included in this cost estimate. Liability protections address the fact that if damages are caused by transportation of CO_2, the transporting party may bear a financial liability. Several types of liability are available (Bonding, Insurance, etc.). The liability regime has yet to be established on a state or federal level. However, some states (Wyoming, North Dakota, and Louisiana) have established trust funds ($5 MM) and liability timeframes (on average 10 years).

Considering all of the above, ETC considers this option to be economically unreasonable.

In summary, ETC believes that CCS is not BACT due to technical, environmental, and economic reasons.

4.3.3.5 STEP 5 | Select BACT

As shown previously, ETC is implementing the following technologies that together meet BACT for Stack GHG emissions:

- Use of electric-driven engines (100%);
- Install Amine Unit and TEG Dehydration Unit flash tank offgas recovery systems (100%);
- Routing the Amine Unit and TEG Dehydration Unit regenerator vents to a thermal oxidizer (99% for methane, generates CO_2);
- Control of engine starter vents by the flare (98% for methane, generates CO_2);
- Installation of compressor blowdown recovery system, and routing remaining blowdown gas to the flare (98% for methane, generates CO_2);
- Use of dual-drive engines when technically available and establishment of federally-enforceable limits on gas-fired operations (28,000 hr/yr for 8 engines combined, which is based upon an average of 3,500 hr/yr each) (60%);
- Fuel selection/switching (28% when comparing natural gas and No. 2 Fuel Oil);
- Burner management systems on the heaters, with intelligent flame ignition, flame intensity controls, and flue gas recirculation (10-25%);
- Air/fuel ratio controllers associated with lean burn engines (5-25%);
- Efficient engine/heater and burner design (10%);
- Energy efficiency (4-17% of electricity consumption) using high efficiency motors and variable speed drives;
- Proper flare and thermal oxidizer operation (1-15%);
- Annual tune-ups and maintenance (1-10%);
- Oxygen trim control associated with lean burn engines (1-3%); and
- Limit of start-up operations to 30 minutes for engines, heaters, and reboilers.

4.3.4 Piping Fugitives GHG BACT

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane and CO_2. The total estimated fugitive CO_2 and methane emissions as CO_2e have a very minor contribution to the Plant's total GHG emissions. However, for completeness it is addressed in this BACT analysis.

ETC will be implementing the 28VHP Leak Detection and Repair (LDAR) program at the Plant to minimize emissions from piping fugitive leaks. While this operational practice is designed to reduce VOC emissions, it has a collateral effect on GHG emissions.

In addition, the compressor seals will be dry seal instead of wet seal. Periodic inspection and maintenance of the compressor rod packing will be conducted annually to determine when the packing needs replacing or any of the components need servicing.

Where possible, the use of low-bleed gas-driven pneumatic controllers will be installed to reduce methane venting. Also, where feasible, pneumatic controllers will be driven by instrument air instead of natural gas to lower methane emissions.

In summary, ETC believes that the use of dry seal rather than wet seal compressors, use of rod packing for reciprocating compressors, the use of low bleed and air driven pneumatic controllers, where practicable, and the implementation of the 28VHP LDAR program will reduce GHG emissions by 80-90%, thereby constituting BACT.

4.3.4.1 STEP 1 | Identify All Potential Control Technologies

The following control technologies for process fugitive emissions of CO_2e are listed below:

- Implementation of a LDAR program: LDAR programs are designed to control VOC emissions and vary in stringency. LDAR is currently only required for VOC sources. Methane is not considered a VOC, so LDAR is not required for streams containing a high content of methane. Organic vapor analyzers or cameras are commonly used in LDAR programs. TCEQ's 28VHP LDAR is currently the most stringent program, which can achieve efficiencies of 97% for valves. ETC will implement TCEQ's 28VHP program on all VOC lines associated with the Project; this program will result in a collateral reduction of GHG emissions from these piping components;
- Use of dry compressor seals: The use of dry compressor seals instead of wet seals can reduce leaks;
- Use of rod packing for reciprocating compressors: ETC will utilize rod packing and will conduct annual inspections of the packing materials; and
- Use of low-bleed gas-driven pneumatic controllers or compressed air-driven pneumatic controllers: low-bleed gas-driven pneumatic controllers emit less gas (that contains GHG) than standard gas-driven controllers, and compressed air-driven pneumatic controllers do not emit GHG.

4.3.4.2 STEP 2 | Eliminate Technically Infeasible Option

All of the technologies listed in Step 1 are technically feasible.

4.3.4.3 STEP 3 | Rank Remaining Control Technologies

ETC intends to implement all technologies listed in Step 1, which together will reduce Fugitive GHG emissions by 80-90%. Therefore, ETC is not ranking the technologies individually. For comparison purposes, the Table 4-6 presents the LDAR parameters for the proposed 28VHP program and other LDAR programs. As shown in the attached table, the LDAR proposed for the Project is the top BACT.

4.3.4.4 STEP 4 | Evaluate the Remaining Control Efficiencies

Because ETC intends to implement TCEQ's 28VHP LDAR program, which is the top-ranked technology, there is no need for evaluation under Step 4.

4.3.4.5 STEP 5 | Select BACT

ETC proposes that implementing TCEQ's 28VHP LDAR program for all components in VOC service, the use of dry compressor seals and rod packing for reciprocating compressors, annual inspection of packing materials, and the use of low-bleed gas-driven pneumatic controllers or compressed air-driven pneumatic controllers where feasible constitutes BACT for fugitive GHG emissions.

TABLE 4-6

COMPARISON OF LDAR PROGRAMS
AIR PERMIT APPLICATION
JACKSON COUNTY GAS PLANT
ETC TEXAS PIPELINE, LTD.

Component Type	Leak Definition (ppmv)				
	TCEQ 28LAER (Proposed)	TCEQ 28VHP	TCEQ 30 TAC 115[a]	NSPS KKK	NSPS GGGa and VVa
Valves-Gas	500	500	500	10,000	500
Valves-Light Liquid	500	500	500	10,000	500
Valves-Heavy Liquid	AVO Program[b]	AVO Program[b]	AVO Program[b]	AVO Program[b]	AVO Program[b]
Pressure Relief Valve-Gas	500	500	500	10,000	500
Pressure Relief Valve-Liquid	500	500	500	10,000	AVO Program[b]
Pumps-Light Liquid	500	2,000	10,000	AVO Program[b]	2,000
Pumps-Heavy Liquid	AVO Program[b]	AVO Program[b]	AVO Program[b]	AVO Program[b]	AVO Program[b]
Flanges/Connectors [c]	NA	NA	NA	AVO Program[b]	500
VOC Compressors	500	2,000	10,000	Seal System	Seal System
Closed Vent Systems	500	500	500	500	500

[a] From 30 TAC Chapter 115, Subchapter D, Division 3: Fugitive Emission Control in Petroleum Refining, Natural Gas/Gasoline Processing, and Petrochemical Processes in Ozone Nonattainment Areas.

[b] AVO Program is a formal audio/visual/olfactory (AVO) program including stipulated periodic inspections, as-needed follow-up monitoring, and as-needed follow-up repairs, and documentation.

[c] Except as noted, requirement does not stipulate a monitoring program for flanges/connectors. However, flange/connector monitoring must be performed to use control efficiency in calculating potential and actual emissions. The add-on TCEQ monitoring program for flanges/connectors is 28CNTA.

5 REGULATORY APPLICABILITY

The following sections demonstrate that the Project emissions sources will meet the applicable federal and state air quality rules and regulations defined in 30 TAC §116.111(a)(2). Furthermore, the following sections also demonstrate that the ETC Jackson County Gas Plants will be operated in accordance with the intent of the Federal Clean Air Act and the Texas Clean Air Act, including protection of the health and physical property of the people.

5.1 Protection of Public Health and Welfare - §116.111 (a)(2)(A)

As outlined below, the proposed emissions from this project will comply with all TCEQ rules and regulations and with the intent of the Texas Clean Air Act.

5.1.1 30 TAC 101 - General Air Quality Rules

The Site will be operated in accordance with the General Rules relating to circumvention, nuisance, traffic hazard, notification requirements for major upset, notification requirements for maintenance, sampling, sampling ports, emissions inventory requirements, sampling procedures and terminology, compliance with Environmental Protection Agency Standards, the National Primary and Secondary Air Quality Standards, inspection fees, emissions fees, and all other applicable General Rules.

5.1.2 30 TAC 111 - Control of Air Pollution from Visible Emissions and Particulate Matter

The potential applicability of this chapter to sources in this application is explained in the following table. Brief explanations of compliance are provided for all applicable rules.

Section Number	Reference	Applicability	Compliance Explanation
§§111.111-113	Visible Emissions	Yes	All exhaust stacks will have flow rates much lower than 100,000 acfm and will have less than 20% opacity.
§§111.121-129	Solid Waste Incineration	No	The Site will not conduct solid waste incineration activities under this application.
§§111.131-139	Abrasive Blasting of Water Storage Tanks Performed by Portable Operations	No	Abrasive blasting of water storage tanks is not being proposed as part of this permit application.

Section Number	Reference	Applicability	Compliance Explanation
§§111.141-149	Materials Handling, Construction, Roads, Streets, Alleys and Parking Lots	No	The Site is located in Jackson County, which is not within the geographic area of applicability.
§111.151	Allowable Emission Limits on Nonagricultural Processes	Yes	The Site's particulate emissions will be less than the allowable emission limits specified in §111.151.
§111.153	Emission Limits for Steam Generators	No	The Site is not proposing to operate a steam generator, as defined in this section, as part of this application.
§§111.171-175	Emission Limits on Agricultural Processes	No	The Site will not conduct agricultural processes as part of this application.
§§111.181-183	Exemptions for Portable or Transient Operations	No	The Site is not a portable or transient operation.
§§111.201-221	Outdoor Burning	Yes	Any outdoor burning that may be conducted at the Site will be done in accordance with these requirements.

5.1.3 30 TAC 112 - Control of Air Pollution from Sulfur Compounds

30 TAC 112 governs various sulfur compound emissions including sulfur dioxide, hydrogen sulfide, sulfuric acid, and total reduced sulfur compounds. The potential applicability of this chapter to sources in this application is explained in the following table. Brief explanations of compliance are provided for all applicable rules.

Section Number	Reference	Applicability	Compliance Explanation
§§112.3-4	SO_2 Net Ground Level Concentrations	Yes	As part of its application to TCEQ for preconstruction authorization, ETC is conducting air dispersion modeling to demonstrate that the Site's net ground level SO_2 concentrations meet the standards in this rule.
§§112.5-7	Allowable SO_2 Emission Rates	No	There are no sulfuric acid or sulfur recovery plants in this permit application.

Section Number	Reference	Applicability	Compliance Explanation
§112.8	Allowable SO_2 Emission Rates	No	There are no solid fossil fuel-fired steam generators in this permit application.
§112.9	Allowable SO_2 Emission Rates	No	There will be no liquid fuel-fired steam generators, furnaces, or heaters in this permit application.
§112.14	Allowable SO_2 Emission Rates	No	The Project will not include any nonferrous smelters.
§§112.15-18	Temporary Fuel Shortage Plan	No	ETC does not anticipate a shortage of low sulfur fuel.
§§112.19-21	Area Control Plan	No	ETC does not anticipate needing relief from the requirements of §112.3.
§§112.31-34	Allowable Emissions of H_2S	Yes	If ETC facilities in this application will produce H_2S emissions, ETC will comply with this rule. Upon request, ETC will conduct dispersion modeling to demonstrate compliance with the property line standards in this rule.
§§112.41-47	Allowable Emissions of H_2SO_4	Yes	Any potential H_2SO_4 emissions will comply with this rule; however, none are expected.
§§112.51-59	Emission Limits for Total Reduced Sulfur Compounds	No	The Site will not include a Kraft Pulp Mill.

5.1.4 30 TAC 113 - Hazardous Air Pollutant (HAP) Standards

30 TAC 113 addresses the control of air pollution from HAPs and other designated facilities, defined within this chapter to be certain air emissions from municipal solid waste landfills (MSWLFs), medical waste incinerators, and certain other processes/emissions regulated under 40 CFR Parts 61 and 63. The Site will not include a MSWLF or medical waste incinerator, nor is the Site anticipated to produce radionuclide emissions or be classified as a synthetic organic chemical manufacturing industry (SOCMI). Consequently, Subchapters B, D, and E are not applicable.

30 TAC 113 Subchapter C implements 40 CFR Part 63 by regulating HAP emissions released from source categories listed in this rule. ETC has facilities in this application which are subject to the source category regulations.

MACT HH (40 CFR Part 63 Subpart HH – National Emissions Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities) outlines specific requirements for major or area sources at oil and natural gas production facilities. The Site is subject to requirements for ancillary equipment in VHAP service and glycol dehydration units. However, per 40 CFR §63.760(g)(1), ancillary equipment also subject to NSPS KKK are only required to comply with NSPS KKK. The glycol dehydration unit vents emit less than 0.9 megagrams of benzene annually prior to control and are exempt from requirements per 40 CFR 63.764(e)(1)(ii). Records will be maintained documenting the dehydration unit emissions using the methods specified in 63.772(b)(2).

MACT ZZZZ (40 CFR Part 63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines) outlines specific requirements for new or modified engines at major and area sources of HAPs. The Site is a major source of HAPs, and the engines will comply with the requirements of MACT ZZZZ.

MACT DDDDD (40 CFR Part 63 Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters) outlines specific requirements for industrial, commercial, and institutional boilers and process heaters at major sources of HAPs. The site is a major source of HAPs and will comply with requirements for the large gaseous fuel process heaters (capacity > 10 MMBtu/hr). Small gaseous fuel process heaters (capacity ≤ 10 MMBtu/hr) are exempt from requirements per 40 CFR §63.7506(c)(4).

5.1.5 30 TAC 114 - Control of Air Pollution from Motor Vehicles

The Site production operations will not include a motor vehicle fleet. Any on-site company vehicles will be used for maintenance only. Therefore, this chapter does not apply.

5.1.6 30 TAC 115 - Control of Air Pollution from Volatile Organic Compounds (VOC)

30 TAC Chapter 115 regulates VOC emissions according to source type and Site location (county). The Site will be located in Jackson County, which is defined as a “covered attainment county” under this rule. Therefore, the potential applicability of the 30 TAC 115 sections is addressed in the following table. Brief explanations of compliance are provided for all applicable rules.

Section Number	Reference	Applicability	Compliance Explanation
§§115.112-119	Storage of VOC	No	The Site will be located in Jackson County, which is not within the geographic area of applicability.
§§115.120-129	Vent Gas Control	No	The Site will be located in Jackson County, which is not within the geographic area of applicability.

Section Number	Reference	Applicability	Compliance Explanation
§§115.131-139	Water Separation	No	The Site will be located in Jackson County, which is not within the geographic area of applicability.
§§115.140-149	Industrial Wastewater	No	The Site will be located in Jackson County, which is not within the geographic area of applicability.
§§115.152-159	Municipal Solid Waste Landfills	No	The Site will be located in Jackson County, which is not within the geographic area of applicability.
§§115.160-169	Batch Processes	No	The Site will be located in Jackson County, which is not within the geographic area of applicability.
§§115.211-259	VOC Transfer Operations	No	Although the Site is in a covered attainment county, it does not include gasoline loading operations. Therefore, these sections do not apply.
§§115.311-359	Petroleum Refining, Natural Gas Processing, and Petrochemical Processes	No	The Site will be located in Jackson County, which is not within the geographic area of applicability.
§§115.412-419	Degreasing Processes	No	The Site will be located in Jackson County, which is not within the geographic area of applicability.
§§115.420-429	Surface Coating Processes	No	The Site will be located in Jackson County, which is not within the geographic area of applicability.
§§115.430-449	Printing Processes	No	Facilities in this application will not conduct printing operations as defined in these sections.
§§115.510-559	Miscellaneous Industrial Sources	No	Facilities in this application will not conduct any of the miscellaneous industrial activities defined in this section.
§§115.600-629	Consumer-Related Sources and Products	No	Facilities in this application will not produce consumer products.

Section Number	Reference	Applicability	Compliance Explanation
§§115.720-789	Highly-Reactive Volatile Organic Compounds (HRVOC)	No	The Site is not located in the Houston-Galveston nonattainment area.
§§115.901-950	Administrative Provisions	No	This rule is not applicable to this Site, so these sections do not apply.

5.1.7 30 TAC 117 - Control of Air Pollution from Nitrogen Compounds

30 TAC 117 governs NO_X emissions from the following types of facilities: Major Sources in an applicable ozone nonattainment area, acid manufacturers, and gas-fired combustion unit manufacturers, distributors, retailers, and installers. 30 TAC 117 also governs NO_X emissions from Minor Sources located in the Houston/Galveston ozone nonattainment area and sources located in specified counties in Central and East Texas. The Project will be located in Jackson County and is not located in any of the ozone nonattainment areas, is not located in a named county of Central or East Texas, nor is it classified as one of the above-named facilities. Consequently, this chapter is not applicable to the Site.

5.1.8 30 TAC 118 - Control of Air Pollution Episodes

The ETC Jackson County Gas Plants 1, 2, 3, and 4 will operate in compliance with the TCEQ General Rules and the Air Pollution Episodic Requirements of 30 TAC 118.

5.1.9 30 TAC 122 - Federal Operating Permits

30 TAC 122 addresses the Texas implementation of the federal operating permits program promulgated under Title V of the Clean Air Act. Based on its potential to emit, as reflected by this application, the Project will be classified as a Major Source. Consequently, ETC will submit an application for a Title V operating permit prior to start of operation of the Project, in accordance with this rule.

5.1.10 Impact on Nearby Schools

As shown on the Figure 2-1 Area Map, no schools are located within 3,000 feet of the Site.

5.2 Measurement of Emissions - §116.111(a)(2)(B)

At the request of the Executive Director of the TCEQ, ETC will provide provisions for the measurement of significant emissions, including the installation of sampling ports, platforms, etc.

5.3 Best Available Control Technology (BACT) - §116.111(a)(2)(C)

Refer to Section 4.0 for a BACT analysis.

5.4 New Source Performance Standards (NSPS) - §116.111(a)(2)(D)

New Source Performance Standards (NSPS) are found in 40 CFR Part 60 and outline specific requirements for certain types of new or modified sources. The following paragraphs describe the NSPS that potentially apply to the Project.

5.4.1 NSPS Dc

NSPS Dc (40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units) outlines specific requirements for steam generating units built after June 9, 1989 with a heat duty between 10 MMBtu and 100 MMBtu. Eight (8) process heaters (H-1706, H-7810, H-2706, H-7811, H-3706, H-7812, H-4706, and H-7813) are affected sources under this subpart, but they have no requirements due to firing only natural gas.

5.4.2 NSPS Kb

NSPS Kb (40 CFR Part 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984) outlines specific requirements for storage vessels containing volatile organic liquids. NSPS Kb is not applicable to storage vessels with a capacity less than 75 cubic meters (472 barrels). All project tanks have a storage capacity less than 75 cubic meters, and, therefore, they are exempt from NSPS Kb.

5.4.3 NSPS KKK

NSPS KKK (40 CFR Part 60 Subpart KKK - Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing) outlines specific requirements for natural gas processing plant fugitive components that were constructed, reconstructed, or modified after January 20, 1984. The Project will have equipment that is subject to this Subpart; therefore, ETC will comply with this rule for the applicable equipment components to be installed as part of this Project.

5.4.4 NSPS JJJJ

NSPS JJJJ (40 CFR Part 60 Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines) outlines specific requirements for new or modified engines. According to §60.4230(a)(4)(i), engines with a maximum engine power greater than or equal to 500 horsepower (hp) (except lean burn engines greater than or equal to 500 hp and less than 1,350 hp) manufactured after July 1, 2007 are subject to the standards. The Project will have twenty (20) new lean burn engines each with a maximum engine power greater than 1,350 hp; thus, these engines meet the applicability criteria and will comply with this rule.

5.5 National Emission Standards for Hazardous Air Pollutants -§116.111(a)(2)(E)

National Emission Standards for Hazardous Air Pollutants (NESHAPs) have been established in 40 CFR Part 61 for various materials, including radon, beryllium, mercury, vinyl chloride, radionuclides, benzene, asbestos, and inorganic arsenic emissions from various types of sources. The Site will not be subject to any subparts of this rule.

5.6 NESHAPs for Source Categories - §116.111 (a)(2)(F)

Additional NESHAPs (also known as MACT standards) have been established in 40 CFR Part 63 for various source categories and/or industries. As previously noted, the Project will be a major source of HAPs, and ETC will comply with any applicable requirements in these rules.

5.6.1 MACT HH

MACT HH (40 CFR Part 63 Subpart HH – National Emissions Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities) outlines specific requirements for major or area sources at oil and natural gas production facilities. The Site is subject to requirements for ancillary equipment in VHAP service and glycol dehydration units. However, per 40 CFR §63.760(g)(1), ancillary equipment also subject to NSPS KKK are only required to comply with NSPS KKK. The glycol dehydration unit vents emit less than 0.9 megagrams of benzene annually prior to control and are exempt from requirements per 40 CFR 63.764(e)(1)(ii). Records will be maintained documenting the dehydration unit emissions using the methods specified in 63.772(b)(2).

5.6.2 MACT ZZZZ

MACT ZZZZ (40 CFR Part 63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines) outlines specific requirements for new or modified engines at major and area sources of HAPs. The Site is a major source of HAPs, and the engines will comply with the requirements of MACT ZZZZ.

5.6.3 MACT DDDDD

MACT DDDDD (40 CFR Part 63 Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters) outlines specific requirements for industrial, commercial, and institutional boilers and process heaters at major sources of HAPs. The site is a major source of HAPs and will comply with requirements for the large gaseous fuel process heaters (capacity > 10 MMBtu/hr). Small gaseous fuel process heaters (capacity ≤ 10 MMBtu/hr) are exempt from requirements per 40 CFR §63.7506(c)(4).

5.7 Performance Demonstration - §116.111 (a)(2)(G)

The Project will be operated as represented in this application and will achieve the specified performance levels. Upon TCEQ request, additional information can be submitted to further demonstrate that operational levels and emission limitations are being upheld. Moreover, ETC will conduct performance tests in accordance with the applicable NSPS and MACT rules.

5.8 Nonattainment Review - §116.111(a)(2)(H)

The nonattainment new source review provisions specified in §116.150 are not applicable because the Project will be located in an area designated as attainment/unclassifiable for all criteria air pollutants.

5.9 Prevention of Significant Deterioration (PSD) Review - §116.111(a)(2)(I)

The PSD review provisions specified in §116.160 are applicable to the Project because the proposed Project will be a new major source of emissions as that term is defined in 40 CFR §52.21. Therefore, the Project triggers PSD review for GHG under EPA permitting authority and for CO, NO_X, PM, PM_{10}, $PM_{2.5}$, and VOC under TCEQ permitting authority.

5.10 Air Dispersion Modeling - §116.111(a)(2)(J)

Because there is no National Ambient Air Quality Standard (NAAQS) for GHG, ETC is not conducting air dispersion modeling in support of this GHG PSD air permit application.

However, ETC has conducted an Air Quality Analysis (AQA) for the Project in support of the PSD application submitted to TCEQ, under TCEQ's permitting authority. The AQA demonstrated that the proposed Project off-site contaminant impacts will be in compliance with state and federal requirements. In accordance with EPA guidance, ETC has provided a copy of the AQA Protocol Document and AQA Report to EPA.

5.11 Hazardous Air Pollutants - 116.111(a)(2)(K)

The proposed Site will be a major source of HAPs and will be subject to Chapter 116, Subchapter E. Project sources will comply with MACT standards promulgated under 40 CFR Part 63.

5.12 Mass Cap and Trade Allowances - 116.111 (a)(2)(L)

The Site will not be located in the Houston/Galveston area and will therefore not be subject to Chapter 101, Subchapter H, Division 3 relating to the Mass Emissions Cap and Trade Program.

6 AIR QUALITY ANALYSIS

This section of ETC's GHG PSD air permit application addresses the air quality impacts. As stated previously, because there is no NAAQS for GHG, ETC is not conducting GHG air dispersion modeling for the Project.

Ambient monitoring for GHG is not required because EPA regulations provide an exemption in sections §52.21(i)(5)(iii) and 51.166(i)(5)(iii) for pollutants that are not listed in the appropriate section of the regulations, and GHG are not currently included in that list. Sections §52.21(m)(1)(ii) and §51.166(m)(1)(ii) of EPA's regulations apply to pollutants for which no NAAQS exists. However, GHG is not considered to effect ambient air quality as defined in Section §52.21(m)(1)(ii) or §51.166(m)(1)(ii) as was intended when these rules were written. This approach is consistent with the EPA Tailoring Rule which includes the following statement with respect to these requirements:

> *"There are currently no NAAQS or PSD increments established for GHG, and therefore these PSD requirements would not apply for GHG, even when PSD is triggered for GHG."*

Because there is currently no NAAQS or PSD increment established for GHG, no further assessment is required.

7 REFERENCES

The following references have been used in the preparation of this PSD air permit application document. Where appropriate, certain materials have been included in the appendices to this document.

- Arizona Department of Environmental Quality. *Technical Support Document and Statement of Basis for Construction of Arizona Clean Fuels Yuma, LLC.* Page 161. February 3, 2005.
- California Environmental Protection Agency. Air Resources Board. *309 Selective Catalytic Reduction Control Theory and Design*. http://www.arb.ca.gov/cap/manuals/cntrldev/sncr_etc/309scr.htm
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- State of Texas. Texas Administrative Code. Title 30, Chapter 113. *Standards of Performance for Hazardous Air Pollutants and for Designated Facilities and Pollutants.* May 14, 2009.
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- State of Texas. Texas Administrative Code. Title 30, Chapter 116. *Control of Air Pollution by Permits for New Construction or Modification.* March 17, 2011.
- State of Texas. Texas Administrative Code. Title 30, Chapter 117. *Control of Air Pollution from Nitrogen Compounds.* May 15, 2011.
- State of Texas. Texas Commission on Environmental Quality. *Technical Guideline Document for Equipment Leak Fugitives*. October 2000.
- Tennessee Valley Authority. Office of Agricultural and Chemical Development. Technical *Assessment of NO_X Removal Processes for Utility Application*. November 1977. http://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=20006JEL.txt
- United States. Code of Federal Regulations. Title 40, Part 52. *Approval and Promulgation of Implementation Plans*. July 2010.

- United States. Code of Federal Regulations. Title 40, Part 60. *New Source Performance Standards*. July 2010.
- United States. Code of Federal Regulations. Title 40, Part 63. *National Emissions Standards for Hazardous Air Pollutants*. July 2010.
- United States. Code of Federal Regulations. Title 40, Part 98. *Mandatory Reporting of Greenhouse Gases*. November 2010.
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- United States. Department of Energy. National Energy Technology Laboratory. *The Economics of CO_2 Storage.* Gemma Heddle. August 2003. http://sequestration.mit.edu/pdf/LFEE_2003-003_RP.pdf
- United States. Environmental Protection Agency. AP-42. Fifth Edition. *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources*. *Section 1.4, Natural Gas Combustion.* July 1998.
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APPENDIX A
TCEQ AIR PERMIT APPLICATION FORMS AND TABLES

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

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. Attachments — Describe Any Attachments: *(ex. Title V Application, Waste Transporter Application, etc.)*

☑ Yes ☐ No — Air Permit Application

3. Customer Reference Number *(if issued)*: CN 601587652

Follow this link to search for CN or RN numbers in Central Registry**

4. Regulated Entity Reference Number *(if issued)*: RN TBD

SECTION II: Customer Information

5. Effective Date for Customer Information Updates (mm/dd/yyyy): _-/__/2011

6. Customer Role (Proposed or Actual) – *as it relates to the Regulated Entity listed on this form. Please check only one of the following:*

☐ Owner ☐ Operator ☑ Owner & Operator
☐ Occupational Licensee ☐ Responsible Party ☐ Voluntary Cleanup Applicant ☐ Other: ____________

7. General Customer Information

☐ New Customer ☐ Update to Customer Information ☐ Change in Regulated Entity Ownership
☐ Change in Legal Name (Verifiable with the Texas Secretary of State) ☑ No Change**

***If "No Change" and Section I is complete, skip to Section III – Regulated Entity Information.*

8. Type of Customer:	☐ Corporation	☐ Individual	☐ Sole Proprietorship- D.B.A
☐ City Government	☐ County Government	☐ Federal Government	☐ State Government
☐ Other Government	☐ General Partnership	☐ Limited Partnership	☐ Other: ____________

9. Customer Legal Name *(If an individual, print last name first: ex: Doe, John)*	*If new Customer, enter previous Customer below*	*End Date:*

10. Mailing Address:

City		State		ZIP		ZIP + 4	

11. Country Mailing Information *(if outside USA)*	12. E-Mail Address *(if applicable)*

13. Telephone Number	14. Extension or Code	15. Fax Number *(if applicable)*

16. Federal Tax ID *(9 digits)*	17. TX State Franchise Tax ID *(11 digits)*	18. DUNS Number *(if applicable)*	19. TX SOS Filing Number *(if applicable)*

20. Number of Employees: ☐ 0-20 ☐ 21-100 ☐ 101-250 ☐ 251-500 ☐ 501 and higher

21. Independently Owned and Operated? ☐ Yes ☐ No

SECTION III: Regulated Entity Information

22. 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 ☐ No Change** *(See below)*

**If "NO CHANGE" is checked and Section I is complete, skip to Section IV, Preparer Information.

23. Regulated Entity Name *(name of the site where the regulated action is taking place)*

Jackson County Gas Plant

24. Street Address of the Regulated Entity: *(No P.O. Boxes)*	800 Sonterra Blvd., Suite 400							
	City	San Antonio	State	TX	ZIP	78258	ZIP + 4	3941
25. Mailing Address:	800 Sonterra Blvd., Suite 400							
	City	San Antonio	State	TX	ZIP	78258	ZIP + 4	3941
26. E-Mail Address:								

27. Telephone Number	28. Extension or Code	29. Fax Number *(if applicable)*
(210) 403-7300		(210) 403-7500

30. Primary SIC Code (4 digits)	31. Secondary SIC Code (4 digits)	32. Primary NAICS Code (5 or 6 digits)	33. Secondary NAICS Code (5 or 6 digits)
1321		211112	

34. What is the Primary Business of this entity? *(Please do not repeat the SIC or NAICS description.)*

Natural Gas and NGL Treating and Processing

Questions 34 – 37 address geographic location. Please refer to the instructions for applicability.

35. Description to Physical Location:	From Ganado, take FM 710 north for 4.5 miles to Galow Rd. Turn left and go 1.25 miles to site on right.

36. Nearest City	County	State	Nearest ZIP Code
Ganado	Jackson	TX	77962

37. Latitude (N) In Decimal:			38. Longitude (W) In Decimal:		
Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
29	6	34.46	96	32	15.52

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 or the updates may not be made. If your Program is not listed, check other and write it in. See the Core Data Form instructions for additional guidance.

☐ Dam Safety	☐ Districts	☐ Edwards Aquifer	☐ Industrial Hazardous Waste	☐ Municipal Solid Waste
☑ New Source Review – Air	☐ OSSF	☐ Petroleum Storage Tank	☐ PWS	☐ Sludge
☐ Stormwater	☐ Title V – Air	☐ Tires	☐ Used Oil	☐ Utilities
☐ Voluntary Cleanup	☐ Waste Water	☐ Wastewater Agriculture	☐ Water Rights	☐ Other:

SECTION IV: Preparer Information

40. Name:	Stephanie Engwall	41. Title:	Director Air Programs
42. Telephone Number	43. Ext./Code	44. Fax Number	45. E-Mail Address
(469) 365-1120	N/A	(469) 365-1199	sengwall@titanengineering.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 9 and/or as required for the updates to the ID numbers identified in field 39.

(See the Core Data Form instructions for more information on who should sign this form.)

Company:	Energy Transfer Company	Job Title:	Environmental Manager
Name *(In Print)*:	Jeff Weiler	Phone:	210-403-7323
Signature:		Date:	8/24/11

TCEQ

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

Update: The TCEQ **requires** that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued by the TCEQ and no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to the TCEQ Web site at www.tceq.state.tx.us/permitting/central_registry/guidance.html.

I. APPLICANT INFORMATION		
A. Company or Other Legal Name: ETC Texas Pipeline, Ltd.		
Texas Secretary of State Charter/Registration Number (*if applicable*):		
B. Company Official Contact Name (☒ Mr. ☐ Mrs. ☐ Ms. ☐ Dr.): Robert Truesdell		
Title: Vice President of Operations		
Mailing Address: 800 E. Sonterra Blvd., Suite 400		
City: San Antonio	State: Texas	ZIP Code: 78258
Telephone No: (210) 403-7300	Fax No.: (210) 403-7500	E-mail Address: robert.truesdell@energytransfer.com
C. Technical Contact Name (☒ Mr. ☐ Mrs. ☐ Ms. ☐ Dr.): Jeff Weiler		
Title: Environmental Manager		
Company Name: ETC Texas Pipeline, Ltd.		
Mailing Address: 800 E. Sonterra Blvd., Suite 400		
City: San Antonio	State: Texas	ZIP Code: 78258
Telephone No.: (210) 403-7323	Fax No.: (210) 403-7523	E-mail Address: jeff.weiler@energytransfer.com
D. Facility Location Information:		
Street Address:		
If no street address, provide clear driving directions to the site in writing:		
From Ganado, take FM 710 north for 4.5 miles to Galow Rd. Turn left and go 1.25 miles to site on right.		
City: Ganado	County: Jackson	ZIP Code: 77962
E. TCEQ Account Identification Number (leave blank if new site or facility):		
F. Is a TCEQ Core Data Form (TCEQ Form No. 10400) attached?		☒ YES ☐ NO
G. TCEQ Customer Reference Number *(leave blank if unknown):* CN601587652		
H. TCEQ Regulated Entity Number *(leave blank if unknown)*:		
II. IMPORTANT GENERAL INFORMATION		
A. Is confidential information submitted with this application?		☐ YES ☒ NO
If "YES," is each "confidential" page marked "**CONFIDENTIAL**" in large red letters?		☐ YES ☐ NO

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II. IMPORTANT GENERAL INFORMATION (*continued*)			
B. Is this application in response to a TCEQ investigation or enforcement action?			☐ YES ☒ NO
If "YES", attach a copy of any correspondence from the TCEQ			
C. Number of New Jobs:			
D. Names of the State Senator and district number for this facility site: Senator Glenn Hegar, District 18			
Names of State Representative and district number for this facility site: Representative Geanie Morrison, District 30			
E. For Concrete Batch Plants, and PSD, or Nonattainment Permits that require public notice, name of the County Judge for this facility site: Judge Dennis Simons			
Mailing Address: 115 W. Main, Room 207			
City: Edna	State: Texas	ZIP Code: 77957	
F. For Concrete Batch Plants, is the facility located in a municipality or an extraterritorial jurisdiction of a municipality?			☐ YES ☐ NO
If "YES," list the name(s) of the Presiding Officer(s) for this facility site:			
Mailing Address:			
City:	State:	ZIP Code:	
III. FACILITY AND SOURCE INFORMATION			
A. Site Name: Jackson County Gas Plant			
B. Area Name/Type of Facility: Natural Gas Processing Plant			☒ Permanent ☐ Portable
C. Principal Company Product or Business: Natural Gas and NGL Treating & Processing Plant			
Principal Standard Industrial Classification Code: 1321			
D. Projected Start of Construction Date: 05/01/12	Projected Start of Operation Date: 12/01/12		
IV. TYPE OF PERMIT ACTION REQUESTED			
A. Permit Number *(if existing)*:			
B. Is this an initial permit application?			☒ YES ☐ NO
If "YES," check the type of permit requested *(check all that apply)*: ☒ State Permit ☐ Nonattainment Federal Permit ☐ Flexible Permit ☒ Prevention of Significant Deterioration Federal Permit ☐ Multiple Plant Permit ☐ Hazardous Air Pollutants Permit Federal Clean Air Act § 112(g) Other: ______			

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IV. TYPE OF PERMIT ACTION REQUESTED *(continued)*	
C. Is this a permit amendment?	☐ YES ☒ NO
Is this a permit revision?? (SB 1126 change)	☐ YES ☒ NO
If "YES," check the type of permit requested *(check all that apply):* ☐ State Permit Amendment ☐ Flexible Permit Amendment ☐ Multiple Plant Permit Amendment ☐ Nonattainment Major Modification ☐ Prevention of Significant Deterioration Major Modification ☐ Hazardous Air Pollutants Permit Federal Clean Air Act § 112(g) Modification Other:________________	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with Senate Bill 1673? [THSC 382.055(a)(2)](80th Legislative)	☐ YES ☒ NO
E. Is this application for a change of location of previously permitted facilities?	☐ YES ☒ NO
If "YES," answer IVE. 1. - IVE. 4.	
1. Current location of facility:	
Street Address *(If no street address, provide clear driving directions to the site in writing.)*:	
City: / County: / ZIP Code:	
2. Proposed location of facility:	
Street Address *(If no street address, provide clear driving directions to the site in writing.)*:	
City: / County: / ZIP Code:	
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions?	☐ YES ☐ NO
If "NO," attach detailed information.	
4. Is the site where the facility is moving considered major?	☐ YES ☐ NO
F. Is this a relocation?	☐ YES ☒ NO
G. Are there any standard permits, exemptions or permits by rule to be consolidated into this permit?	☐ YES ☒ NO

IV. TYPE OF PERMIT ACTION REQUESTED *(continued)*	
H. Are you permitting a facility or group of facilities that have planned maintenance, startup and shutdown emissions that cannot be authorized by a permit by rule or standard permit or that are authorized by a permit by rule or standard permit and are being rolled into this permit?	☒ YES ☐ NO
If "YES," attach information on any changes to emissions under this application as specified in Sections IX, and X.	
If "YES," answer IVH. 1 -IVH. 3.	
1. Are the activities to be included in this permit covered by any previously existing MSS authorizations?	☐ YES ☒ NO
If "YES," provide a listing of all other authorizations (permit by rule or standard permit and the associated registration number if any).	
2. Have the emissions been previously submitted as part of an emissions inventory?	☐ YES ☒ NO
3. List which years the MSS activities were included in emissions inventory submittals:	
I. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability)	
Is this facility located at a site required to obtain a federal operating permit under 30 TAC Chapter 122?	☒ YES ☐ NO ☐ To be Determined
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this PI-1 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	
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site (check all that apply)	
☐ GOP Issued ☐ GOP application/revision application: submitted or under APD review ☐ SOP Issued ☐ SOP application/revision application: submitted or under APD review	
V. PERMIT FEE INFORMATION	
A. Fee paid for this application:	$ 75,000.00
1. Is a copy of the check or money order attached to the original submittal of this application?	☒ YES ☐ NO ☐ N/A
2. Is a Table 30 entitled, "Certification of estimated Capital Cost and Fee Verification," attached?	☒ YES ☐ NO ☐ N/A

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VI. PUBLIC NOTICE APPLICABILITY	
A. Is this a new permit application or a change of location application?	☒ YES ☐ NO
B. Is this an application for a major modification of a PSD, NA or 30 TAC § 112(g) permit?	☐ YES ☒ NO
C. Is this a state permit amendment application?	☐ YES ☒ NO
If "YES," answer VIC. 1. - VIC. 3.	
1. Is there any change in character of emissions in this application?	☐ YES ☐ NO
Is there a new air contaminant in this application?	☐ YES ☐ NO
2. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
3. List the total annual emission increases associated with the application (*list <u>all</u> that apply*):	
Volatile Organic Compounds (VOC):	tpy
Sulfur Dioxide (SO_2):	tpy
Carbon Monoxide (CO):	tpy
Hazardous Air Pollutants (HAPs):	tpy
Nitrogen Oxides (NO_x):	tpy
Particulate Matter (PM):	tpy
PM_{10}:	tpy
$PM_{2.5}$:	tpy
Lead (Pb):	tpy
Other air contaminants not listed above: CO2e = 665,776.83	tpy

VII. PUBLIC NOTICE INFORMATION ***(complete if applicable)***		
A. Responsible Person:		
Name (☒ Mr. ☐Mrs. ☐Ms. ☐Dr.): Danny Schedule		
Title: Director of Operations for the Southern Region		
Mailing Address: 800 E. Sonterra Blvd., Suite 400		
City: San Antonio	State: Texas	ZIP Code: 78258
Telephone No.: (210) 403-7300	Fax No.: (210) 403-7500	E-mail Address: danny.schedule@energytransfer.com

VII. PUBLIC NOTICE INFORMATION ***(complete if applicable)***		
B. Technical Contact:		
Company Name : ETC Texas Pipeline, Ltd.		
Name (☒ Mr. ☐Mrs. ☐Ms. ☒Dr.): Jeff Weiler		
Title: Environmental Manager		
Mailing Address: 800 E. Sonterra Blvd., Suite 400		
City: San Antonio	State: Texas	ZIP Code: 78258
Telephone No.: (210) 403-7323	Fax No.: (210) 403-7523	E-mail Address: jeff.weiler@energytransfer.com
C. Application in Public Place:		
Name of Public Place: Jackson County Memorial Library		
Physical Address: 411 North Wells Street		
City: Edna	County: Jackson	
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 ☐ N/A	
Complete VII.D. 1. - VII.D. 3., as applicable.		
D.1. Name of the Mayor for this facility site:		
Mailing Address:		
City:	State:	ZIP Code:
D.2. Name of the Federal Land Manager for this facility site:		
Mailing Address:		
City:	State:	ZIP Code:
D.3. Name of the Indian Governing Body for this facility site:		
Mailing Address:		
City:	State:	ZIP Code:

VII. PUBLIC NOTICE INFORMATION *(complete if applicable)*				
E. 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," which language is **required** by the bilingual program?	SPANISH			
VIII. 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 source under 30 TAC Chapter 122, Federal Operating Permit Program?				☒ YES ☐ NO
C. Are the site emissions of any individual air contaminant greater than 50 tpy?				☒ YES ☐ NO
D. Are the site emissions of all air contaminants combined greater than 75 tpy?				☒ YES ☐ NO
IX. TECHNICAL INFORMATION				
A. Is a current area map attached?				☒ YES ☐ NO
Are any schools located within 3,000 feet of this facility?				☐ YES ☒ NO
B. Is a plot plan of the plant property attached?				☒ YES ☐ NO
C. Is a process flow diagram and a process description attached?				☒ YES ☐ NO
D. Maximum Operating Schedule:	Hours: 24	Day(s): 7	Week(s): 52	Year(s): 8760 hrs/yr
Seasonal Operation?				☐ YES ☒ NO
If "YES," please describe.				
E. Are worst-case emissions data and calculations attached?				☒ YES ☐ NO
1. Is a Table 1(a) entitled, "Emission Point Summary Table," attached?				☒ YES ☐ NO
2. Is a Table 2 entitled, "Material Balance Table," attached?				☐ YES ☒ NO
3. Are equipment, process, or control device tables attached?				☒ YES ☐ NO
F. Are actual emissions for the last two years (determination federal applicability) attached?				☐ YES ☒ NO

X.	**STATE REGULATORY REQUIREMENTS** *Applicants must be in compliance with all applicable state regulations to obtain a permit or amendment.*	
A.	The emissions from the proposed facility will comply with all rules and regulations of the TCEQ and details are attached?	☒ YES ☐ NO
B.	The proposed facility will be able to measure emissions of significant air contaminants and details are attached?	☒ YES ☐ NO
C.	A demonstration of Best Available Control Technology (BACT) is attached?	☒ YES ☐ NO
D.	The proposed facilities will achieve the performance in the permit application and compliance demonstration or record keeping information is attached?	☒ YES ☐ NO
E.	Is atmospheric dispersion modeling attached?	☒ YES ☐ NO
F.	Does this application involve any air contaminants for which a "disaster review" is required?	☐ YES ☒ NO
If "YES," details must be attached.		
Note: For a list of air contaminants for which a "disaster review" will be required, refer to the NSRPD Disaster Review Guidance Document at www.tceq.state.tx.us/permitting/air/rules/federal/63/63hmpg.html.		
G.	Is this facility or group of facilities located at a site within an Air Pollutant Watch List (APWL) area?	☐ YES ☒ NO
If "YES," answer X.G. 1. - X.G. 3.		
1.	List the APWL Site Number:	
2.	Does the site emit a pollutant of concern for the APWL area in which the site is located?	☐ YES ☐ NO
3.	If "YES," list the pollutant(s) of concern emitted by this site:	
H.	Is this facility or group of facilities located at a site within the Houston/Galveston nonattainment area? (Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, or Waller Counties)	☐ YES ☒ NO
If "YES," answer X.H. 1. - X.H. 4.		
1.	Does the facility or group of facilities located at this site have an uncontrolled design capacity to emit 10 tpy or more of NO_X?	☐ YES ☐ NO
2.	Is this site subject to 30 TAC Chapter 101, Subchapter H, Division 3 (Mass Emissions Cap and Trade)?	☐ YES ☐ NO
3.	Does this action make the site subject to 30 TAC Chapter 101, Subchapter H, Division 3 (Mass Emissions Cap and Trade)?	☐ YES ☐ NO
4.	Does this action require the site to obtain additional emission allowances?	☐ YES ☐ NO

XI. FEDERAL REGULATORY REQUIREMENTS **Applicants must be in compliance with all applicable federal regulations to obtain a permit or amendment**. ***If any of the following questions are answered "YES, the application must contain detailed attachments addressing applicability, identify federal regulation Subparts, show how requirements are met, and include compliance information.***	
A. Does a 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 a 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO
D. Does nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E. Does prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F. Does Hazardous Air Pollutant Major Source [FAA § 112(g)] requirements apply to this application?	☐ YES ☒ NO
XII. COPIES OF THIS APPLICATION	
A. Has the required fee been sent separately with a copy of this Form PI-1 to the TCEQ Revenue Section? *(MC 214, P.O. Box 13088, Austin, Texas 78711).*	☒ YES ☐ NO ☐ NA
B. Are the Core Data Form, Form PI-1, and all attachments being sent to the TCEQ in Austin?	☒ YES ☐ NO
OPTIONAL: Has an extra copy of the Core Data Form, Form PI-1 and all attachments been sent to the TCEQ in Austin?	☒ YES ☐ NO
If "YES," please mark this application as "COPY."	
C. Is a copy of the Core Data Form, the Form PI-1, and all attachments being sent to the appropriate TCEQ regional office?	☒ YES ☐ NO
D. Is a copy of the Core Data Form, the Form PI-1, and all attachments being sent to each appropriate local air pollution control program(s)?	☐ YES ☒ NO
List all local air pollution control program(s):	
E. Is a copy of the Core Data Form, Form PI-1, and all attachments (without confidential information) being sent to the EPA Region 6 office in Dallas, Texas? (federal applications only)	☒ YES ☐ NO
F. This facility is located within 100 kilometers of the Rio Grande River and a copy of the application was sent to the International Boundary and Water Commission (IBWC):	☐ YES ☒ NO
G. This facility is located within 100 kilometers of a federally-designated Class I area and a copy of the application was sent to the appropriate Federal Land Manager:	☐ YES ☒ NO

XIII. PROFESSIONAL ENGINEER (P.E.) SEAL	
Is the estimated capital cost of the project greater than $2 million dollars?	Yes
If "YES," the application must be submitted under the seal of a Texas licensed Professional Engineer (P.E.).	

XIV. DELINQUENT FEES AND PENALTIES

Notice: 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.state.tx.us/agency/delin/index.html.

XV. SIGNATURE

The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA. I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. I further state that I have read and understand TWC §§ 7.177-7.183, which defines CRIMINAL OFFENSES for certain violations, including intentionally or knowingly making or causing to be made false material statements or representations in this application, and TWC § 7.187, pertaining to CRIMINAL PENALTIES.

NAME: Robert Truesdell

SIGNATURE: Robert Truesdell

Original Signature Required

DATE: 8/24/11

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emissions Point Summary

Permit Number:	TBD	RN Number		Date:	Revised March 2012
Company Name:	ETC Texas Pipeline, Ltd. - Jackson County Gas Plant				

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

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate [a]		4. UTM Coordinates of Emission Point			Source							
									5. Building Height (ft)	6. Height Above Ground	7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	NAME (C)		Pounds per Hour (A)	TPY (B)	Zone	East (meters)	North (meters)			Diameter (ft) (A)	Velocity (fps) (B)	Tempera-ture (C)	Length (ft) (A)	Width (ft) (B)	Axis Degrees (C)
C-1100A/B, C-2100A/B, C-3100A/B, & C-4100A/B	C-1100A/B, C-2100A/B, C-3100A/B, & C-4100A/B	All Inlet Compressors Combined Annual Operations (28,000 hrs/yr Total)	CO_2e	--	21,966.06	14	--	--	--	--	--	--	--	--	--	--
C-1121A	C-1121A	Plant 1 Residue Compressor 1 (3616)	CO_2e	--	18,213.22	14	739,506.1	3,222,653.5	--	70.0	2.5	101.3	800	--	--	--
C-1121B	C-1121B	Plant 1 Residue Compressor 2 (3616)	CO_2e	--	18,213.22	14	739,506.6	3,222,639.4	--	70.0	2.5	101.3	800	--	--	--
C-1121C	C-1121C	Plant 1 Residue Compressor 3 (3616)	CO_2e	--	18,213.22	14	739,507.3	3,222,625.5	--	70.0	2.5	101.3	800	--	--	--
C-2121A	C-2121A	Plant 2 Residue Compressor 1 (3616)	CO_2e	--	18,213.22	14	739,652.4	3,222,659.5	--	70.0	2.5	101.3	800	--	--	--
C-2121B	C-2121B	Plant 2 Residue Compressor 2 (3616)	CO_2e	--	18,213.22	14	739,652.9	3,222,645.5	--	70.0	2.5	101.3	800	--	--	--
C-2121C	C-2121C	Plant 2 Residue Compressor 3 (3616)	CO_2e	--	18,213.22	14	739,653.4	3,222,631.5	--	70.0	2.5	101.3	800	--	--	--
C-3121A	C-3121A	Plant 3 Residue Compressor 1 (3616)	CO_2e	--	18,213.22	14	739,804.6	3,222,665.6	--	70.0	2.5	101.3	800	--	--	--
C-3121B	C-3121B	Plant 3 Residue Compressor 2 (3616)	CO_2e	--	18,213.22	14	739,805.3	3,222,651.8	--	70.0	2.5	101.3	800	--	--	--
C-3121C	C-3121C	Plant 3 Residue Compressor 3 (3616)	CO_2e	--	18,213.22	14	739,805.6	3,222,637.8	--	70.0	2.5	101.3	800	--	--	--
C-4121A	C-4121A	Plant 4 Residue Compressor 1 (3616)	CO_2e	--	18,213.22	14	739,957.1	3,222,671.3	--	70.0	2.5	101.3	800	--	--	--
C-4121B	C-4121B	Plant 4 Residue Compressor 2 (3616)	CO_2e	--	18,213.22	14	739,957.7	3,222,657.3	--	70.0	2.5	101.3	800	--	--	--
C-4121C	C-4121C	Plant 4 Residue Compressor 3 (3616)	CO_2e	--	18,213.22	14	739,958.3	3,222,643.3	--	70.0	2.5	101.3	800	--	--	--
H-1706	H-1706	Plant 1 Hot Oil Heater	CO_2e	--	24,854.83	14	739,493.8	3,222,815.1	--	50.0	3	77.1	775	--	--	--
H-7810	H-7810	Plant 1 Trim Heater	CO_2e	--	8,917.00	14	739,450.8	3,222,804.0	--	17.8	3	18.5	850	--	--	--
H-7820	H-7820	Plant 1 Mol Sieve Regen Heater	CO_2e	--	4,970.98	14	739,488.0	3,222,797.0	--	17.8	2.5	18.5	850	--	--	--
H-7410	H-7410	Plant 1 TEG Dehy Unit Regen Gas Heater	CO_2e	--	1,537.42	14	739,451.0	3,222,785.0	--	20.0	1	27.6	800	--	--	--
TO-1	TO-1, F-1117, F-1527	Plant 1 Thermal Oxidizer (Amine Unit and Dehy Vents)	CO_2e	--	48,377.05	14	739,485.0	3,222,807.0	--	75.0	3	150.4	1400	--	--	--
H-2706	H-2706	Plant 2 Hot Oil Heater	CO_2e	--	24,854.83	14	739,640.1	3,222,820.9	--	50.0	3	77.1	775	--	--	--
H-7811	H-7811	Plant 2 Trim Heater	CO_2e	--	8,917.00	14	739,596.7	3,222,810.0	--	17.8	3	18.5	850	--	--	--
H-7821	H-7821	Plant 2 Mol Sieve Regen Heater	CO_2e	--	4,970.98	14	739,634.0	3,222,803.0	--	17.8	2.5	18.5	850	--	--	--
H-7411	H-7411	Plant 2 TEG Dehy Unit Regen Gas Heater	CO_2e	--	1,537.42	14	739,598.0	3,222,791.0	--	20.0	1	27.6	800	--	--	--
TO-2	TO-2, F-2117, F-2527	Plant 2 Thermal Oxidizer (Amine Unit and Dehy Vents)	CO_2e	--	48,377.05	14	739,631.0	3,222,813.0	--	75.0	3	150.4	1400	--	--	--
H-3706	H-3706	Plant 3 Hot Oil Heater	CO_2e	--	24,854.83	14	739,792.2	3,222,827.2	--	50.0	3	77.1	775	--	--	--

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emissions Point Summary

Permit Number:	TBD	RN Number		Date:	Revised March 2012
Company Name:	ETC Texas Pipeline, Ltd. - Jackson County Gas Plant				

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

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS											
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate [a]		4. UTM Coordinates of Emission Point			5. Building Height (ft)	6. Height Above Ground	Source: 7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	NAME (C)		Pounds per Hour (A)	TPY (B)	Zone	East (meters)	North (meters)			Diameter (ft) (A)	Velocity (fps) (B)	Tempera-ture (C)	Length (ft) (A)	Width (ft) (B)	Axis Degrees (C)
H-7812	H-7812	Plant 3 Trim Heater	CO_2e	--	8,917.00	14	739,749.3	3,222,815.8	--	17.8	3	18.5	850	--	--	--
H-7822	H-7822	Plant 3 Mol Sieve Regen Heater	CO_2e	--	4,970.98	14	739,787.0	3,222,809.0	--	17.8	2.5	18.5	850	--	--	--
H-7412	H-7412	Plant 3 TEG Dehy Unit Regen Gas Heater	CO_2e	--	1,537.42	14	739,750.0	3,222,798.0	--	20.0	1	27.6	800	--	--	--
TO-3	TO-3, F-3117, F-3527	Plant 3 Thermal Oxidizer (Amine Unit and Dehy Vents)	CO_2e	--	48,377.05	14	739,783.0	3,222,819.0	--	75.0	3	150.4	1400	--	--	--
H-4706	H-4706	Plant 4 Hot Oil Heater	CO_2e	--	24,854.83	14	739,945.0	3,222,832.6	--	50.0	3	77.1	775	--	--	--
H-7813	H-7813	Plant 4 Trim Heater	CO_2e	--	8,917.00	14	739,901.5	3,222,821.7	--	17.8	3	18.5	850	--	--	--
H-7823	H-7823	Plant 4 Mol Sieve Regen Heater	CO_2e	--	4,970.98	14	739,939.0	3,222,815.0	--	17.8	2.5	18.5	850	--	--	--
H-7413	H-7413	Plant 4 TEG Dehy Unit Regen Gas Heater	CO_2e	--	1,537.42	14	739,902.0	3,222,803.0	--	20.0	1	27.6	800	--	--	--
TO-4	TO-4, F-4117, F-4527	Plant 4 Thermal Oxidizer (Amine Unit and Dehy Vents)	CO_2e	--	48,377.05	14	739,936.0	3,222,825.0	--	75.0	3	150.4	1400	--	--	--
P1-FUG	P1-FUG	Plant 1 Fugitives	CO_2e	--	61.74	14	739,466.5	3,222,829.0	--	--	--	--	--	800	300	178
P2-FUG	P2-FUG	Plant 2 Fugitives	CO_2e	--	61.74	14	739,618.5	3,222,836.0	--	--	--	--	--	800	300	178
P3-FUG	P3-FUG	Plant 3 Fugitives	CO_2e	--	61.74	14	739,771.0	3,222,842.0	--	--	--	--	--	800	300	178
P4-FUG	P4-FUG	Plant 4 Fugitives	CO_2e	--	61.74	14	739,923.3	3,222,847.4	--	--	--	--	--	800	300	178
FS-800	FS-800, GRP-BDSV	Plant Flare	CO_2e	--	4,258.65	14	739,282.4	3,222,790.0	--	50.0	11.33	65.6	1832	--	--	--
Existing, Unmodified PBR Sources																
STAB-FUG	STAB-FUG	Stabilization Unit Fugitives	CO_2e	--	5.32	14	739,343.6	3,222,488.5	--	--	--	--	--	400	115	88
H-741	H-741	Stabilization Unit Heater	CO_2e	--	3,269.56	14	739,344.8	3,222,549.5	--	16.5	2.5	8.9	850	--	--	--
TL-Flare	TL-Flare, C-LOAD	Truck Loading Flare (Controlled Condensate Loading)	CO_2e	--	982.82	14	739,252.0	3,222,788.7	--	50.0		65.6	1832	--	--	--

[a] All emission rates are estimated values only and should not be considered maximum allowable emission rates.

TABLE 6

BOILERS AND HEATERS

Type of Device: Hot Oil Heater			Manufacturer:		
Number from flow diagram: H-1706, H-2706, H-3706, H-4706			Model Number:		
CHARACTERISTICS OF INPUT					
Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)		
Natural Gas			Average 800 scfm	Design Maximum	
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air		
		(specify units) 1,010 Btu/scf	Average ____ scfm* 20 % excess (vol)	Design Maximum ____ scfm * 20 % excess (vol)	

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

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

STACK PARAMETERS					
Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
3 feet	50 feet	77.1		775	13,975

CHARACTERISTICS OF OUTPUT	
Material	Chemical Composition of Exit Gas Released (% by Volume)
	See Table 1(a) for EPN H-1706, H-2706, H-3706, and H-4706
Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.	

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

*Standard Conditions: 70°F,14.7 psia

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TABLE 6

BOILERS AND HEATERS

Type of Device: Trim Heater				Manufacturer:			
Number from flow diagram: H-7810, H-7811, H-7812, H-7813				Model Number:			
CHARACTERISTICS OF INPUT							
Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)				
Natural Gas			Average 287.1 scfm	Design Maximum			
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air				
		(specify units) 1,010 Btu/scf	Average ____ scfm* 20 % excess (vol)	Design Maximum ____ scfm * 20 % excess (vol)			

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

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

STACK PARAMETERS					
Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
3 feet	17.8 feet	18.5		850	3,161

CHARACTERISTICS OF OUTPUT	
Material	Chemical Composition of Exit Gas Released (% by Volume)
	See Table 1(a) for EPN H-7810, H-7811, H-7812, and H-7813
Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.	

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

*Standard Conditions: 70°F,14.7 psia

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TABLE 6

BOILERS AND HEATERS

Type of Device: Mol Sieve Regen Heater			Manufacturer:			
Number from flow diagram: H-7820, H-7821, H-7822, H-7823			Model Number:			
CHARACTERISTICS OF INPUT						
Type Fuel	Chemical Composition (% by Weight)		Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)		
Natural Gas				Average 160 scfm	Design Maximum	
			Gross Heating Value of Fuel	Total Air Supplied and Excess Air		
			(specify units) 1,010 Btu/scf	Average ____ scfm* 20 % excess (vol)	Design Maximum ____ scfm * 20 % excess (vol)	

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

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

STACK PARAMETERS					
Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
2.5 feet	17.8 feet	18.5		850	3,161

CHARACTERISTICS OF OUTPUT	
Material	Chemical Composition of Exit Gas Released (% by Volume)
	See Table 1(a) for EPN H-7820, H-7821, H-7822, and H-7823
Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.	

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

*Standard Conditions: 70°F,14.7 psia

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TABLE 6

BOILERS AND HEATERS

Type of Device: TEG Dehy Unit/Regen Gas Heater	Manufacturer:
Number from flow diagram: H-7410, H-7411, H-7412, H-7413	Model Number:

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas			Average 49.5 scfm	Design Maximum
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 1,010 Btu/scf	Average ____ scfm* 20 % excess (vol)	Design Maximum ____ scfm * 20 % excess (vol)

HEAT TRANSFER MEDIUM

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

OPERATING CHARACTERISTICS

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

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
1 foot	20 feet	27.6		800	545

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	See Table 1(a) for EPN H-7410, H-7411, H-7412, and H-7413

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

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

*Standard Conditions: 70°F,14.7 psia

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TABLE 6

BOILERS AND HEATERS

Type of Device: Stabilization Unit Heater	Manufacturer:
Number from flow diagram: H-741	Model Number:

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas			Average 95.7 scfm	Design Maximum
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 1,010 Btu/scf	Average ____ scfm* 20 % excess (vol)	Design Maximum ____ scfm * 20 % excess (vol)

HEAT TRANSFER MEDIUM

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

OPERATING CHARACTERISTICS

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

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
2.5 feet	16.5 feet	8.9		850	1,056

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	See Table 1(a) for EPN H-741

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

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

*Standard Conditions: 70°F,14.7 psia

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TABLE 8

FLARE SYSTEMS

Number from Flow Diagram	Manufacturer & Model No. (if available)
FS-800	

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Max.
		(scfm [68°F,14.7 psia])	(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])
	1. Inlet Gas	0	333	3,000
	2. Fuel Gas	0	1,167	14,000
	3. Propane	0	333	4,000
	4.			
	5.			
	6.			
	7.			
	8.			
% of time this condition occurs		74%	26%	0%

	Flow Rate (scfm [68°F, 14.7 psia])		Temp. °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	0	21,000	69.78	800
Fuel Added to Gas Steam	1.7	1.7	69.78	690

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

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

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

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

Flare Height (ft)	50	Flare tip inside diameter (ft)

Capital Installed Cost $_____________ Annual Operating Cost $______________

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

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TABLE 8

FLARE SYSTEMS

Number from Flow Diagram	Manufacturer & Model No. (if available)
TL-Flare	

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Max.
		(scfm [68°F,14.7 psia])	(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])
	1. Condensate Vapors	0	1.1	6
	2.			
	3.			
	4.			
	5.			
	6.			
	7.			
	8.			
% of time this condition occurs				

	Flow Rate (scfm [68°F, 14.7 psia])		Temp. °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	0	6	68.83	0.3
Fuel Added to Gas Steam	1.7	1.7	69.78	690

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

For Stream Injection	Stream Pressure (psig)		Total Stream Flow	Temp. °F	Velocity (ft/sec)
	Min. Expected	Design Max.	Rate (lb/hr)		
	Number of Jet Streams	Diameter of Steam Jets (inches)		Design basis for steam injected (lb steam/lb hydrocarbon)	

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

Flare Height (ft)	50	Flare tip inside diameter (ft)	0.44

Capital Installed Cost $_____________ Annual Operating Cost $______________

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

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Table 29
RECIPROCATING ENGINES

ENGINE DATA

Emission Point Number From Table 1(a) C-1100A&B, C-2100A&B, C-3100A&B, C-4100A&B

APPLICATION

✓ Gas Compression
___ Electric Generation
___ Refrigeration
___ Other (Specify) ___

Manufacturer Caterpillar
Model No. G3606
Serial No. ___
Orig. Mfr. Date ___
Rebuild Date(s) ___
No. of Cylinders ___
Compression Ratio 9:1

✓ 4 Stroke Cycle ___ Carburetted ___ Spark Ignited ___ Dual Fuel
___ 2 Stroke Cycle ___ Fuel Injected ___ Diesel

Naturally Aspirated ___ Blower/Pump Scavenged ___ Turbocharged & I.C. ✓
Turbocharged ___ Intercooled (I.C.) ___ I.C. Water Temperature ___

Ignition/Injection Timing: ___Fixed ___Variable

	Mfg. Rating	Proposed Operating Range
Horsepower	1775	1775
Speed (rpm)	1000	1000

FUEL DATA

___ Field Gas ___ Landfill Gas ___ LP Gas ___ Other
✓ Natural Gas ___ Digester Gas ___ Diesel

Engine Fuel Consumption 7,555 BTU/bhp-hr
Heat Value (specify units) 1,010 (HHV) (HHV) (LHV)
Fuel Sulfur Content 4 ppm (grains/100 scf)(weight percent)

FULL LOAD EMISSIONS DATA

No_x 0.50 g/bhp-hr CO 0.19 g/bhp-hr
___ ppmv ___ ppmv
VOC(C_3^+) 0.27 g/bhp-hr Total HC ___ g/bhp-hr
___ ppmv ___ ppmv

Attach information showing emissions versus engine speed and load.

Method of Emissions Control:

✓ Lean Operation ___ Parameter Adjustment ___ SCR Catalyst
___ Stratified Charge ___ NSCR Catalyst ✓ Other (Specify) Oxidation Catalyst

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. A copy of engine manufacturer's site rating or general rating specification for the engine model.
B. Tyical fuel analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
C. Description of air/fuel ratio control system (manufacturers's information acceptable).
D. Details regarding principle of operation of emissions controls. If add-on equipment is used, provide make and model and manufacturer's information.
E. Exhaust parameter information on Table 1(a).

Table 29
RECIPROCATING ENGINES

ENGINE DATA

Emission Point Number From Table 1(a) C-1121A,B&C; C-2121A,B&C; C-3121A,B&C, C-4121A,B&C

Manufacturer Caterpillar
Model No. G3616
Serial No. ______
Orig. Mfr. Date ______
Rebuild Date(s) ______
No. of Cylinders ______
Compression Ratio ______

APPLICATION

✓ Gas Compression
___ Electric Generation
___ Refrigeration
___ Other (Specify) ______

✓ 4 Stroke Cycle
___ 2 Stroke Cycle
___ Carburetted
___ Fuel Injected
___ Spark Ignited
___ Diesel
___ Dual Fuel

Naturally Aspirated ___
Turbocharged ___
Blower/Pump Scavenged ___
Intercooled (I.C.) ___
Turbocharged & I.C. ✓
I.C. Water Temperature ___

Ignition/Injection Timing: ___ Fixed ___ Variable

	Mfg. Rating	Proposed Operating Range
Horsepower	4735	4735
Speed (rpm)	1000	1000

FUEL DATA

___ Field Gas
✓ Natural Gas
___ Landfill Gas
___ Digester Gas
___ LP Gas
___ Diesel
___ Other

Engine Fuel Consumption 7,505 BTU/bhp-hr
Heat Value (specify units) 1,010 (HHV) (HHV) (LHV)
Fuel Sulfur Content 4 ppm (grains/100 scf)(weight percent)

FULL LOAD EMISSIONS DATA

No_x 0.05 g/bhp-hr
___ ppmv
CO 0.19 g/bhp-hr
___ ppmv
VOC(C_3^+) 0.27 g/bhp-hr
___ ppmv
Total HC ___ g/bhp-hr
___ ppmv

Attach information showing emissions versus engine speed and load.

Method of Emissions Control:

✓ Lean Operation
___ Stratified Charge
___ Parameter Adjustment
___ NSCR Catalyst
✓ SCR Catalyst
✓ Other (Specify) Oxidation Catalyst

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. A copy of engine manufacturer's site rating or general rating specification for the engine model.
B. Tyical fuel analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
C. Description of air/fuel ratio control system (manufacturers's information acceptable).
D. Details regarding principle of operation of emissions controls. If add-on equipment is used, provide make and model and manufacturer's information.
E. Exhaust parameter information on Table 1(a).

APPENDIX B
EMISSION RATE CALCULATIONS

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Description | **Page**

TABLE B-1

SUMMARY OF SITE-WIDE AIR POLLUTANT EMISSION RATES

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

EPN	FIN	Description	CO_2 Annual[a] (T/yr)	CH_4 Annual[a] (T/yr)	N_2O Annual[a] (T/yr)	CO_2e Annual[a] (T/yr)	Adjusted[b] CO_2e Annual (T/yr)
Project-Affected Equipment							
C-1100A/B, C-2100A/B, C-3100A/B, & C4100A/B	C-1100A/B, C-2100A/B, C-3100A/B, & C4100A/B		21,944.53	0.41	0.04	21,966.06	21,966.06
C-1121A	C-1121A	Plant 1 Residue Compressor Engine 1	18,195.38	0.34	0.03	18,213.22	18,213.22
C-1121B	C-1121B	Plant 1 Residue Compressor Engine 2	18,195.38	0.34	0.03	18,213.22	18,213.22
C-1121C	C-1121C	Plant 1 Residue Compressor Engine 3	18,195.38	0.34	0.03	18,213.22	18,213.22
C-2121A	C-2121A	Plant 2 Residue Compressor Engine 1	18,195.38	0.34	0.03	18,213.22	18,213.22
C-2121B	C-2121B	Plant 2 Residue Compressor Engine 2	18,195.38	0.34	0.03	18,213.22	18,213.22
C-2121C	C-2121C	Plant 2 Residue Compressor Engine 3	18,195.38	0.34	0.03	18,213.22	18,213.22
C-3121A	C-3121A	Plant 3 Residue Compressor Engine 1	18,195.38	0.34	0.03	18,213.22	18,213.22
C-3121B	C-3121B	Plant 3 Residue Compressor Engine 2	18,195.38	0.34	0.03	18,213.22	18,213.22
C-3121C	C-3121C	Plant 3 Residue Compressor Engine 3	18,195.38	0.34	0.03	18,213.22	18,213.22
C-4121A	C-4121A	Plant 4 Residue Compressor Engine 1	18,195.38	0.34	0.03	18,213.22	18,213.22
C-4121B	C-4121B	Plant 4 Residue Compressor Engine 2	18,195.38	0.34	0.03	18,213.22	18,213.22
C-4121C	C-4121C	Plant 4 Residue Compressor Engine 3	18,195.38	0.34	0.03	18,213.22	18,213.22
H-1706	H-1706	Plant 1 Hot Oil Heater	24,830.49	0.47	0.05	24,854.83	24,854.83
H-7810	H-7810	Plant 1 Trim Heater	8,908.26	0.17	0.02	8,917.00	8,917.00
H-7820	H-7820	Plant 1 Mol Sieve Regen Heater	4,966.10	0.09	0.01	4,970.98	4,970.98
H-7410	H-7410	Plant 1 TEG Dehy Unit Regen Gas Heater	1,535.91	0.03	0.00	1,537.42	1,537.42
TO-1	TO-1, F-1117, F-1527	Plant 1 Thermal Oxidizer	43,972.72	0.14	0.01	43,979.14	48,377.05
H-2706	H-2706	Plant 2 Hot Oil Heater	24,830.49	0.47	0.05	24,854.83	24,854.83
H-7811	H-7811	Plant 2 Trim Heater	8,908.26	0.17	0.02	8,917.00	8,917.00
H-7821	H-7821	Plant 2 Mol Sieve Regen Heater	4,966.10	0.09	0.01	4,970.98	4,970.98
H-7411	H-7411	Plant 2 TEG Dehy Unit Regen Gas Heater	1,535.91	0.03	0.00	1,537.42	1,537.42
TO-2	TO-2, F-2117, F-2527	Plant 2 Thermal Oxidizer	43,972.72	0.14	0.01	43,979.14	48,377.05
H-3706	H-3706	Plant 3 Hot Oil Heater	24,830.49	0.47	0.05	24,854.83	24,854.83
H-7812	H-7812	Plant 3 Trim Heater	8,908.26	0.17	0.02	8,917.00	8,917.00
H-7822	H-7822	Plant 3 Mol Sieve Regen Heater	4,966.10	0.09	0.01	4,970.98	4,970.98
H-7412	H-7412	Plant 3 TEG Dehy Unit Regen Gas Heater	1,535.91	0.03	0.00	1,537.42	1,537.42
TO-3	TO-3, F-3117, F-3527	Plant 3 Thermal Oxidizer	43,972.72	0.14	0.01	43,979.14	48,377.05
H-4706	H-4706	Plant 4 Hot Oil Heater	24,830.49	0.47	0.05	24,854.83	24,854.83
H-7813	H-7813	Plant 4 Trim Heater	8,908.26	0.17	0.02	8,917.00	8,917.00
H-7823	H-7823	Plant 4 Mol Sieve Regen Heater	4,966.10	0.09	0.01	4,970.98	4,970.98
H-7413	H-7413	Plant 4 TEG Dehy Unit Regen Gas Heater	1,535.91	0.03	0.00	1,537.42	1,537.42
TO-4	TO-4, F-4117, F-4527	Plant 4 Thermal Oxidizer	43,972.72	0.14	0.01	43,979.14	48,377.05
P1-FUG	P1-FUG	Plant 1 Fugitives	0.06	2.67	--	56.13	61.74
P2-FUG	P2-FUG	Plant 2 Fugitives	0.06	2.67	--	56.13	61.74
P3-FUG	P3-FUG	Plant 3 Fugitives	0.06	2.67	--	56.13	61.74
P4-FUG	P4-FUG	Plant 4 Fugitives	0.06	2.67	--	56.13	61.74
FS-800	FS-800,GRP-BDSV	Plant Flare, Compressor Engine Blowdown/Starter Vents to Flare	3531.52	16.101	0.006	3,871.50	4,258.65
		Total Normal Operations:	**580,674.77**	**34.87**	**0.77**	**581,658.20**	**599,659.43**
		Totals Without Fugitives:	**580,674.53**	**24.19**	**0.77**	**581,433.68**	**599,412.47**
		TCEQ PSD Major Source Threshold:	**--**	**--**	**--**	**100,000**	**100,000**
Existing Unmodified Operations							
STAB-FUG	STAB-FUG	Stabilizer Unit Fugitives	0.01	0.23	--	4.84	5.32
H-741	H-741	Stabilization Unit Heater	2,969.42	0.056	0.006	2,972.33	3,269.56
TL-Flare	TL-Flare, C-LOAD	Truck Loading Flare (Controlled Condensate Loading)	893.20	0.001	0.001	893.47	982.82

a Annual emissions for the engines and Plant Flare include MSS.

b Adjusted emissions for thermal oxidizer were increased by 10 percent to allow for process gas variability. Emission calculations are based on a representative sample for current conditions and may change.

COMBUSTION SOURCES POTENTIAL TO EMIT GREENHOUSE GASES

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Combustion-Related Greenhouse Gas Emissions

Combustion Source EPN	HP	Btu/hp-hr	MMBtu/hr	Annual Operating Hours	Fuel Usage MMBtu/yr	CO_2 [a] Emissions short T/yr	CH_4 [a] Emissions short T/yr	N_2O [a] Emissions short T/yr	CO_2e[a] short T/yr	GHG Mass[a] short T/yr
Project-Affected Equipment										
C-1100A/B, C-2100A/B, C-3100A/B, & C-4100A/B	1,775	7,555	13.41	28,000	375,480.00	21,944.53	0.4139	0.0414	21,966.06	21,944.99
C-1121A	4,735	7,505	35.54	8,760	311,330.40	18,195.38	0.3432	0.0343	18,213.22	18,195.76
C-1121B	4,735	7,505	35.54	8,760	311,330.40	18,195.38	0.3432	0.0343	18,213.22	18,195.76
C-1121C	4,735	7,505	35.54	8,760	311,330.40	18,195.38	0.3432	0.0343	18,213.22	18,195.76
C-2121A	4,735	7,505	35.54	8,760	311,330.40	18,195.38	0.3432	0.0343	18,213.22	18,195.76
C-2121B	4,735	7,505	35.54	8,760	311,330.40	18,195.38	0.3432	0.0343	18,213.22	18,195.76
C-2121C	4,735	7,505	35.54	8,760	311,330.40	18,195.38	0.3432	0.0343	18,213.22	18,195.76
C-3121A	4,735	7,505	35.54	8,760	311,330.40	18,195.38	0.3432	0.0343	18,213.22	18,195.76
C-3121B	4,735	7,505	35.54	8,760	311,330.40	18,195.38	0.3432	0.0343	18,213.22	18,195.76
C-3121C	4,735	7,505	35.54	8,760	311,330.40	18,195.38	0.3432	0.0343	18,213.22	18,195.76
C-4121A	4,735	7,505	35.54	8,760	311,330.40	18,195.38	0.3432	0.0343	18,213.22	18,195.76
C-4121B	4,735	7,505	35.54	8,760	311,330.40	18,195.38	0.3432	0.0343	18,213.22	18,195.76
C-4121C	4,735	7,505	35.54	8,760	311,330.40	18,195.38	0.3432	0.0343	18,213.22	18,195.76
H-1706	---	---	48.5	8,760	424,860.00	24,830.49	0.4683	0.0468	24,854.83	24,831.01
H-7410	---	---	3.0	8,760	26,280.00	1,535.91	0.0290	0.0029	1,537.42	1,535.94
H-7810	---	---	17.4	8,760	152,424.00	8,908.26	0.1680	0.0168	8,917.00	8,908.44
H-7820	---	---	9.7	8,760	84,972.00	4,966.10	0.0937	0.0094	4,970.98	4,966.20
H-2706	---	---	48.5	8,760	424,860.00	24,830.49	0.4683	0.0468	24,854.83	24,831.01
H-7411	---	---	3.0	8,760	26,280.00	1,535.91	0.0290	0.0029	1,537.42	1,535.94
H-7811	---	---	17.4	8,760	152,424.00	8,908.26	0.1680	0.0168	8,917.00	8,908.44
H-7821	---	---	9.7	8,760	84,972.00	4,966.10	0.0937	0.0094	4,970.98	4,966.20
H-3706	---	---	48.5	8,760	424,860.00	24,830.49	0.4683	0.0468	24,854.83	24,831.01
H-7412	---	---	3.0	8,760	26,280.00	1,535.91	0.0290	0.0029	1,537.42	1,535.94
H-7812	---	---	17.4	8,760	152,424.00	8,908.26	0.1680	0.0168	8,917.00	8,908.44
H-7822	---	---	9.7	8,760	84,972.00	4,966.10	0.0937	0.0094	4,970.98	4,966.20
H-4706	---	---	48.5	8,760	424,860.00	24,830.49	0.4683	0.0468	24,854.83	24,831.01
H-7413	---	---	3.0	8,760	26,280.00	1,535.91	0.0290	0.0029	1,537.42	1,535.94
H-7813	---	---	17.4	8,760	152,424.00	8,908.26	0.1680	0.0168	8,917.00	8,908.44
H-7823	---	---	9.7	8,760	84,972.00	4,966.10	0.0937	0.0094	4,970.98	4,966.20
TO-1 (Fuel Gas)	---	---	7.0	8,760	61,320.00	3,583.78	0.0676	0.0068	3,587.31	3,583.85
TO-1 (Waste Gas)[b]	---	---				40,388.94	0.0700	0.0046	40,391.83	40,389.01
TO-2 (Fuel Gas)	---	---	7.0	8,760	61,320.00	3,583.78	0.0676	0.0068	3,587.31	3,583.85
TO-2 (Waste Gas)[b]	---	---				40,388.94	0.0700	0.0046	40,391.83	40,389.01
TO-3 (Fuel Gas)	---	---	7.0	8,760	61,320.00	3,583.78	0.0676	0.0068	3,587.31	3,583.85
TO-3 (Waste Gas)[b]	---	---				40,388.94	0.0700	0.0046	40,391.83	40,389.01
TO-4 (Fuel Gas)	---	---	7.0	8,760	61,320.00	3,583.78	0.0676	0.0068	3,587.31	3,583.85
TO-4 (Waste Gas)[b]	---	---				40,388.94	0.0700	0.0046	40,391.83	40,389.01
FS-800 (Pilot Gas)	---	---	0.1	8,760	876.00	51.20	0.0010	0.0001	51.25	51.20
FS-800 (Waste Gas)[b]	---	---				3,480.32	16.1000	0.0059	3,820.25	3,496.43
						580,674.53			**581,433.68**	**580,699.54**
Existing, Unmodified Sources										
H-741	---	---	5.8	8,760	50,808.00	2,969.42	0.0560	0.0056	2,972.33	2,969.48
TL-Flare (Pilot Gas)	---	---	0.10	8,760	876.00	51.20	0.0010	0.0001	51.25	51.20
TL-Flare (Waste Gas)[b]	---	---				842.00	0.0000	0.0007	842.22	842.00

[a]Sample calculations:

CO_2, CH_4, or N_2O = Fuel * HHV * EF (Eq. C-1, §98.33(a)(1)(i) and C-8, §98.33(c)(1))

Where:

CO_2, CH_4, or N_2O = Annual emissions from combustion in kilograms

Fuel = volume combusted, scfy

HHV = High heat value of fuel, MMBtu/scf

EF = Emission Factors from Tables C-1 and C-2 of 40 CFR 98, Subpart C are as follows

CO_2 = 53.02 kg/MMBtu

CH_4 = 0.001 kg/MMBtu

N_2O = 0.0001 kg/MMBtu

The engine design rating in MMBtu/hr was substituteed for Fuel and HHV in Equation C-1 and a conversion from metric tons to short tons was applied in the following sample calculation for EPN-C-1121A:

CO_2 (short T/yr) = (0.001 metric T/kg)*(Fuel usage, MMBtu/yr))*[CO_2 EF, kg/MMBtu] * (2,204.6 lb/metric T) / (2,000 lb/short T)

= 18,195.38 short T/yr

An example calculation for CO_2e in using Eq. A-1 and global warming potential factors found in Table A-1

CO_2e (short T/yr) = (CO2 Emission, short T/yr) + 21 * (CH4 Emission, short T/yr) + 310 * (N2O Emission, short T/y

= 18,213.22 short T/yr

An example calculation for GHG Mass in short T/yr for EPN C-1121A follows:

GHG Mass (short T/yr) = (CO2 Emission, short T/yr) + (CH4 Emission, short T/yr) + (N2O Emission, short T/yr)

= 18,195.76 short T/yr

[b]Waste gas combustion GHG emissions from the flares and thermal oxidizers are calculated on the following sheets.

PLANT 1 PIPING FUGITIVES POTENTIAL TO EMIT

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Component	Number of Components	Emission Factors [a] (lb/hr-component)	Operating Hours (hr/yr)	Maximum Methane (wt%)	Maximum CO_2 (wt%)	Reduction Credit [a] (%)	PTE Methane Hourly [b] (lb/hr)	PTE Methane Annual [c] (T/yr)	PTE CO_2 Hourly [b] (lb/hr)	PTE CO_2 Annual [c] (T/yr)
Valves										
Gas Streams (Inlet)	210	0.00992	8,760	55%	2%	97%	0.0344	0.1506	0.0012	0.0055
Gas Streams (Residue)	315	0.00992	8,760	98%	1%	97%	0.0919	0.4024	0.0009	0.0041
Gas Streams (Processing)	326	0.00992	8,760	55%	2%	97%	0.0534	0.2337	0.0019	0.0085
Light Liquid Streams	262	0.0055	8,760	0%	0%	97%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	105	0.000216	8,760	0%	0%	97%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	525	0.0000185	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Relief Valves							0.0000	0.0000	0.0000	0.0000
Gas Streams (Inlet)	22	0.0194	8,760	55%	2%	97%	0.0070	0.0308	0.0003	0.0011
Gas Streams (Residue)	32	0.0194	8,760	98%	1%	97%	0.0183	0.0799	0.0002	0.0008
Gas Streams (Processing)	32	0.0194	8,760	55%	2%	97%	0.0102	0.0449	0.0004	0.0016
Light Liquid Streams	53	0.0165	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	11	0.0309	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	26	0.0000683	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Compressor Seals										
Gas Streams (Inlet)	13	0.0194	8,760	55%	2%	95%	0.0069	0.0304	0.0003	0.0011
Gas Streams (Residue)	25	0.0194	8,760	98%	1%	95%	0.0238	0.1041	0.0002	0.0011
Gas Streams (Processing)	4	0.0194	8,760	55%	2%	95%	0.0021	0.0093	0.0001	0.0003
Light Liquid Streams	0	0.0165	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	0	0.0309	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	0	0.0000683	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Pump Seals										
Gas Streams (Inlet)	2	0.00529	8,760	55%	2%	0%	0.0058	0.0255	0.0002	0.0009
Gas Streams (Residue)	2	0.00529	8,760	98%	1%	0%	0.0104	0.0454	0.0001	0.0005
Gas Streams (Processing)	2	0.00529	8,760	55%	2%	0%	0.0058	0.0255	0.0002	0.0009
Light Liquid Streams	21	0.02866	8,760	0%	0%	93%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	11	0.000052	8,760	0%	0%	93%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	16	0.00113	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Flanges										
Gas Streams (Inlet)	557	0.00086	8,760	55%	2%	75%	0.0659	0.2885	0.0024	0.0105
Gas Streams (Residue)	820	0.00086	8,760	98%	1%	75%	0.1728	0.7568	0.0018	0.0077
Gas Streams (Processing)	847	0.00086	8,760	55%	2%	75%	0.1002	0.4387	0.0036	0.0160
Light Liquid Streams	708	0.000243	8,760	0%	0%	75%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	274	0.000006	8,760	0%	0%	75%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	1,339	0.00000086	8,760	0%	0%	30%	0.0000	0.0000	0.0000	0.0000
						Gas Streams (Inlet):	**0.1200**	**0.5258**	**0.0044**	**0.0191**
						Gas Streams (Residue):	**0.3172**	**1.3886**	**0.0032**	**0.0142**
						Gas Streams (Processing):	**0.1717**	**0.7521**	**0.0062**	**0.0273**
						Light Liquid Streams:	**0.0000**	**0.0000**	**0.0000**	**0.0000**
						Water/Light Liquid:	**0.0000**	**0.0000**	**0.0000**	**0.0000**
						Heavy Liquid:	**0.0000**	**0.0000**	**0.0000**	**0.0000**
						TOTALS:	**0.61**	**2.67**	**0.01**	**0.06**

[a] Fugitive Emission Factors and Reduction Credits are per TCEQ Technical Guidance Document for Equipment Leak Fugitives, dated October 2000. The emission factors are for total hydrocarbon. Reduction credit is from 28LAER.

[b] Hourly Methane and CO_2 emission rates are calculated as follows:
(210 components) * (0.00992 lb/hr-component) * (55% Methane) * (100% - 97% reduction credit) = 0.0344 lb/hr

[c] Annual Methane and CO_2 emission rates are calculated as follows:
(210 components) * (0.00992 lb/hr-component) * (8,760 hr/yr) * (55% Methane) * (100% - 97% reduction credit) / (2,000 lb/T) = 0.1506 T/yr

PLANT 2 PIPING FUGITIVES POTENTIAL TO EMIT

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Component	Number of Components	Emission Factors [a] (lb/hr-component)	Operating Hours (hr/yr)	Maximum Methane (wt%)	Maximum CO_2 (wt%)	Reduction Credit [a] (%)	PTE Methane Hourly [b] (lb/hr)	PTE Methane Annual [c] (T/yr)	PTE CO_2 Hourly [b] (lb/hr)	PTE CO_2 Annual [c] (T/yr)
Valves										
Gas Streams (Inlet)	210	0.00992	8,760	55%	2%	97%	0.0344	0.1506	0.0012	0.0055
Gas Streams (Residue)	315	0.00992	8,760	98%	1%	97%	0.0919	0.4024	0.0009	0.0041
Gas Streams (Processing)	326	0.00992	8,760	55%	2%	97%	0.0534	0.2337	0.0019	0.0085
Light Liquid Streams	262	0.0055	8,760	0%	0%	97%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	105	0.000216	8,760	0%	0%	97%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	525	0.0000185	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Relief Valves										
Gas Streams (Inlet)	22	0.0194	8,760	55%	2%	97%	0.0070	0.0308	0.0003	0.0011
Gas Streams (Residue)	32	0.0194	8,760	98%	1%	97%	0.0183	0.0799	0.0002	0.0008
Gas Streams (Processing)	32	0.0194	8,760	55%	2%	97%	0.0102	0.0449	0.0004	0.0016
Light Liquid Streams	53	0.0165	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	11	0.0309	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	26	0.0000683	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Compressor Seals										
Gas Streams (Inlet)	13	0.0194	8,760	55%	2%	95%	0.0069	0.0304	0.0003	0.0011
Gas Streams (Residue)	25	0.0194	8,760	98%	1%	95%	0.0238	0.1041	0.0002	0.0011
Gas Streams (Processing)	4	0.0194	8,760	55%	2%	95%	0.0021	0.0093	0.0001	0.0003
Light Liquid Streams	0	0.0165	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	0	0.0309	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	0	0.0000683	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Pump Seals										
Gas Streams (Inlet)	2	0.00529	8,760	55%	2%	0%	0.0058	0.0255	0.0002	0.0009
Gas Streams (Residue)	2	0.00529	8,760	98%	1%	0%	0.0104	0.0454	0.0001	0.0005
Gas Streams (Processing)	2	0.00529	8,760	55%	2%	0%	0.0058	0.0255	0.0002	0.0009
Light Liquid Streams	21	0.02866	8,760	0%	0%	93%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	11	0.000052	8,760	0%	0%	93%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	16	0.00113	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Flanges										
Gas Streams (Inlet)	557	0.00086	8,760	55%	2%	75%	0.0659	0.2885	0.0024	0.0105
Gas Streams (Residue)	820	0.00086	8,760	98%	1%	75%	0.1728	0.7568	0.0018	0.0077
Gas Streams (Processing)	847	0.00086	8,760	55%	2%	75%	0.1002	0.4387	0.0036	0.0160
Light Liquid Streams	708	0.000243	8,760	0%	0%	75%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	274	0.000006	8,760	0%	0%	75%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	1,339	0.00000086	8,760	0%	0%	30%	0.0000	0.0000	0.0000	0.0000
						Gas Streams (Inlet):	**0.1200**	**0.5258**	**0.0044**	**0.0191**
						Gas Streams (Residue):	**0.3172**	**1.3886**	**0.0032**	**0.0142**
						Gas Streams (Processing):	**0.1717**	**0.7521**	**0.0062**	**0.0273**
						Light Liquid Streams:	**0.0000**	**0.0000**	**0.0000**	**0.0000**
						Water/Light Liquid:	**0.0000**	**0.0000**	**0.0000**	**0.0000**
						Heavy Liquid:	**0.0000**	**0.0000**	**0.0000**	**0.0000**
						TOTALS:	**0.61**	**2.67**	**0.01**	**0.06**

[a] Fugitive Emission Factors and Reduction Credits are per TCEQ Technical Guidance Document for Equipment Leak Fugitives, dated October 2000. The emission factors are for total hydrocarbon. Reduction credit is from 28LAER.

[b] Hourly Methane and CO_2 emission rates are calculated as follows:
(210 components) * (0.00992 lb/hr-component) * (55% Methane) * (100% - 97% reduction credit) = 0.0344 lb/hr

[c] Annual Methane and CO_2 emission rates are calculated as follows:
(210 components) * (0.00992 lb/hr-component) * (8,760 hr/yr) * (55% Methane) * (100% - 97% reduction credit) / (2,000 lb/T) = 0.1506 T/yr

PLANT 3 PIPING FUGITIVES POTENTIAL TO EMIT

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Component	Number of Components	Emission Factors [a] (lb/hr-component)	Operating Hours (hr/yr)	Maximum Methane (wt%)	Maximum CO_2 (wt%)	Reduction Credit [a] (%)	PTE Methane Hourly [b] (lb/hr)	PTE Methane Annual [c] (T/yr)	PTE CO_2 Hourly [b] (lb/hr)	PTE CO_2 Annual [c] (T/yr)
Valves										
Gas Streams (Inlet)	210	0.00992	8,760	55%	2%	97%	0.0344	0.1506	0.0012	0.0055
Gas Streams (Residue)	315	0.00992	8,760	98%	1%	97%	0.0919	0.4024	0.0009	0.0041
Gas Streams (Processing)	326	0.00992	8,760	55%	2%	97%	0.0534	0.2337	0.0019	0.0085
Light Liquid Streams	262	0.0055	8,760	0%	0%	97%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	105	0.000216	8,760	0%	0%	97%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	525	0.0000185	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Relief Valves										
Gas Streams (Inlet)	22	0.0194	8,760	55%	2%	97%	0.0070	0.0308	0.0003	0.0011
Gas Streams (Residue)	32	0.0194	8,760	98%	1%	97%	0.0183	0.0799	0.0002	0.0008
Gas Streams (Processing)	32	0.0194	8,760	55%	2%	97%	0.0102	0.0449	0.0004	0.0016
Light Liquid Streams	53	0.0165	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	11	0.0309	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	26	0.0000683	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Compressor Seals										
Gas Streams (Inlet)	13	0.0194	8,760	55%	2%	95%	0.0069	0.0304	0.0003	0.0011
Gas Streams (Residue)	25	0.0194	8,760	98%	1%	95%	0.0238	0.1041	0.0002	0.0011
Gas Streams (Processing)	4	0.0194	8,760	55%	2%	95%	0.0021	0.0093	0.0001	0.0003
Light Liquid Streams	0	0.0165	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	0	0.0309	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	0	0.0000683	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Pump Seals										
Gas Streams (Inlet)	2	0.00529	8,760	55%	2%	0%	0.0058	0.0255	0.0002	0.0009
Gas Streams (Residue)	2	0.00529	8,760	98%	1%	0%	0.0104	0.0454	0.0001	0.0005
Gas Streams (Processing)	2	0.00529	8,760	55%	2%	0%	0.0058	0.0255	0.0002	0.0009
Light Liquid Streams	21	0.02866	8,760	0%	0%	93%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	11	0.000052	8,760	0%	0%	93%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	16	0.00113	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Flanges										
Gas Streams (Inlet)	557	0.00086	8,760	55%	2%	75%	0.0659	0.2885	0.0024	0.0105
Gas Streams (Residue)	820	0.00086	8,760	98%	1%	75%	0.1728	0.7568	0.0018	0.0077
Gas Streams (Processing)	847	0.00086	8,760	55%	2%	75%	0.1002	0.4387	0.0036	0.0160
Light Liquid Streams	708	0.000243	8,760	0%	0%	75%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	274	0.000006	8,760	0%	0%	75%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	1,339	0.00000086	8,760	0%	0%	30%	0.0000	0.0000	0.0000	0.0000
						Gas Streams (Inlet):	**0.1200**	**0.5258**	**0.0044**	**0.0191**
						Gas Streams (Residue):	**0.3172**	**1.3886**	**0.0032**	**0.0142**
						Gas Streams (Processing):	**0.1717**	**0.7521**	**0.0062**	**0.0273**
						Light Liquid Streams:	**0.0000**	**0.0000**	**0.0000**	**0.0000**
						Water/Light Liquid:	**0.0000**	**0.0000**	**0.0000**	**0.0000**
						Heavy Liquid:	**0.0000**	**0.0000**	**0.0000**	**0.0000**
						TOTALS:	**0.61**	**2.67**	**0.01**	**0.06**

[a] Fugitive Emission Factors and Reduction Credits are per TCEQ Technical Guidance Document for Equipment Leak Fugitives, dated October 2000. The emission factors are for total hydrocarbon. Reduction credit is from 28LAER.

[b] Hourly Methane and CO_2 emission rates are calculated as follows:
(210 components) * (0.00992 lb/hr-component) * (55% Methane) * (100% - 97% reduction credit) = 0.0344 lb/hr

[c] Annual Methane and CO_2 emission rates are calculated as follows:
(210 components) * (0.00992 lb/hr-component) * (8,760 hr/yr) * (55% Methane) * (100% - 97% reduction credit) / (2,000 lb/T) = 0.1506 T/yr

PLANT 4 PIPING FUGITIVES POTENTIAL TO EMIT
AIR PERMIT APPLICATION
JACKSON COUNTY GAS PLANT
ETC TEXAS PIPELINE, LTD.

Component	Number of Components	Emission Factors [a] (lb/hr-component)	Operating Hours (hr/yr)	Maximum Methane (wt%)	Maximum CO_2 (wt%)	Reduction Credit [a] (%)	PTE Methane Hourly [b] (lb/hr)	PTE Methane Annual [c] (T/yr)	PTE CO_2 Hourly [b] (lb/hr)	PTE CO_2 Annual [c] (T/yr)
Valves										
Gas Streams (Inlet)	210	0.00992	8,760	55%	2%	97%	0.0344	0.1506	0.0012	0.0055
Gas Streams (Residue)	315	0.00992	8,760	98%	1%	97%	0.0919	0.4024	0.0009	0.0041
Gas Streams (Processing)	326	0.00992	8,760	55%	2%	97%	0.0534	0.2337	0.0019	0.0085
Light Liquid Streams	262	0.0055	8,760	0%	0%	97%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	105	0.000216	8,760	0%	0%	97%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	525	0.0000185	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Relief Valves										
Gas Streams (Inlet)	22	0.0194	8,760	55%	2%	97%	0.0070	0.0308	0.0003	0.0011
Gas Streams (Residue)	32	0.0194	8,760	98%	1%	97%	0.0183	0.0799	0.0002	0.0008
Gas Streams (Processing)	32	0.0194	8,760	55%	2%	97%	0.0102	0.0449	0.0004	0.0016
Light Liquid Streams	53	0.0165	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	11	0.0309	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	26	0.0000683	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Compressor Seals										
Gas Streams (Inlet)	13	0.0194	8,760	55%	2%	95%	0.0069	0.0304	0.0003	0.0011
Gas Streams (Residue)	25	0.0194	8,760	98%	1%	95%	0.0238	0.1041	0.0002	0.0011
Gas Streams (Processing)	4	0.0194	8,760	55%	2%	95%	0.0021	0.0093	0.0001	0.0003
Light Liquid Streams	0	0.0165	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	0	0.0309	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	0	0.0000683	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Pump Seals										
Gas Streams (Inlet)	2	0.00529	8,760	55%	2%	0%	0.0058	0.0255	0.0002	0.0009
Gas Streams (Residue)	2	0.00529	8,760	98%	1%	0%	0.0104	0.0454	0.0001	0.0005
Gas Streams (Processing)	2	0.00529	8,760	55%	2%	0%	0.0058	0.0255	0.0002	0.0009
Light Liquid Streams	21	0.02866	8,760	0%	0%	93%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	11	0.000052	8,760	0%	0%	93%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	16	0.00113	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Flanges										
Gas Streams (Inlet)	557	0.00086	8,760	55%	2%	75%	0.0659	0.2885	0.0024	0.0105
Gas Streams (Residue)	820	0.00086	8,760	98%	1%	75%	0.1728	0.7568	0.0018	0.0077
Gas Streams (Processing)	847	0.00086	8,760	55%	2%	75%	0.1002	0.4387	0.0036	0.0160
Light Liquid Streams	708	0.000243	8,760	0%	0%	75%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	274	0.000006	8,760	0%	0%	75%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	1,339	0.00000086	8,760	0%	0%	30%	0.0000	0.0000	0.0000	0.0000
						Gas Streams (Inlet):	**0.1200**	**0.5258**	**0.0044**	**0.0191**
						Gas Streams (Residue):	**0.3172**	**1.3886**	**0.0032**	**0.0142**
						Gas Streams (Processing):	**0.1717**	**0.7521**	**0.0062**	**0.0273**
						Light Liquid Streams:	**0.0000**	**0.0000**	**0.0000**	**0.0000**
						Water/Light Liquid:	**0.0000**	**0.0000**	**0.0000**	**0.0000**
						Heavy Liquid:	**0.0000**	**0.0000**	**0.0000**	**0.0000**
						TOTALS:	**0.61**	**2.67**	**0.01**	**0.06**

[a] Fugitive Emission Factors and Reduction Credits are per TCEQ Technical Guidance Document for Equipment Leak Fugitives, dated October 2000. The emission factors are for total hydrocarbon. Reduction credit is from 28LAER.

[b] Hourly Methane and CO_2 emission rates are calculated as follows:
(210 components) * (0.00992 lb/hr-component) * (55% Methane) * (100% - 97% reduction credit) = 0.0344 lb/hr

[c] Annual Methane and CO_2 emission rates are calculated as follows:
(210 components) * (0.00992 lb/hr-component) * (8,760 hr/yr) * (55% Methane) * (100% - 97% reduction credit) / (2,000 lb/T) = 0.1506 T/yr

PROJECT-AFFECTED AMINE UNITS POTENTIAL TO EMIT

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Component	Plant 1 Amine Unit Uncontrolled Emissions [a] Inlet Gas Treating Hourly (lb/hr)	Plant 1 Amine Unit Uncontrolled Emissions [a] Inlet Gas Treating Annual (T/yr)	Product Treating Hourly (lb/hr)	Product Treating Annual (T/yr)	Thermal Oxidizer DRE (%)	Plant 1 Amine Unit Total Potential to Emit (FIN: F-1117) Hourly (lb/hr)	Plant 1 Amine Unit Total Potential to Emit (FIN: F-1117) Annual (T/yr)
Nitrogen	0.0012	0.0053	0.0000	0.0000	0%	0.0012	0.0053
Carbon Dioxide	7,773	34,046	898	3,933	0%	8,671.00	37,979.00
Hydrogen Sulfide [b]	0.7500	3.2850	0.0000	0.0000	99.9%	0.0008	0.0033
Methane	11.2922	49.4598	0.0710	0.3110	99.9%	0.0114	0.0498
Ethane	10.8001	47.3044	9.6775	42.3875	99.9%	0.0205	0.0897
Propane	3.8442	16.8376	1.5209	6.6615	99.9%	0.0054	0.0235
i-Butane	0.5657	2.4778	0.1132	0.4958	99.9%	0.0007	0.0030
n-Butane	1.4765	6.4671	0.2378	1.0416	99.9%	0.0017	0.0075
i-Pentane	0.1701	0.7450	0.0217	0.0950	99.9%	0.0002	0.0008
n-Pentane	0.1778	0.7788	0.0174	0.0762	99.9%	0.0002	0.0009
n-Hexane	0.1386	0.6071	0.0067	0.0293	99.9%	0.0001	0.0006
Heptane	0.0086	0.0377	0.0004	0.0018	99.9%	0.0000	0.0000
Octane	0.0049	0.0215	0.0001	0.0004	99.9%	0.0000	0.0000
Benzene	4.5818	20.0683	0.1869	0.8186	99.9%	0.0048	0.0209
Toluene	6.3164	27.6658	0.1336	0.5852	99.9%	0.0065	0.0283
Ethylbenzene	0.2316	1.0144	0.0024	0.0105	99.9%	0.0002	0.0010
m-Xylene	1.2073	5.2880	0.0116	0.0508	99.9%	0.0012	0.0053
o-Xylene	0.2827	1.2382	0.0023	0.0101	99.9%	0.0003	0.0012
p-Xylene	0.9291	4.0695	0.0092	0.0403	99.9%	0.0009	0.0041
DEA	2.99E-15	0.0000	0.0000	0.0000	99.9%	0.0000	0.0000
MDEA	5.07E-11	0.0000	0.0000	0.0000	99.9%	0.0000	0.0000
Total VOC	**19.9353**	**87.3168**	**2.2642**	**9.9171**		**0.0222**	**0.0971**
Adjusted VOC [c]						**0.0244**	**0.1068**

Component	Plant 2 Amine Unit Uncontrolled Emissions [a] From Gas Treating Hourly (lb/hr)	Plant 2 Amine Unit Uncontrolled Emissions [a] From Gas Treating Annual (T/yr)	From Liquids Treating Hourly (lb/hr)	From Liquids Treating Annual (T/yr)	Thermal Oxidizer DRE (%)	Plant 2 Amine Unit Total Potential to Emit (FIN: F-2117) Hourly (lb/hr)	Plant 2 Amine Unit Total Potential to Emit (FIN: F-2117) Annual (T/yr)
Nitrogen	0.0012	0.0053	0.0000	0.0000	0%	0.0012	0.0053
Carbon Dioxide	7,773	34,046	898	3,933	0%	8,671.00	37,979.00
Hydrogen Sulfide [b]	0.7500	3.2850	0.0000	0.0000	99.9%	0.0008	0.0033
Methane	11.2922	49.4598	0.0710	0.3110	99.9%	0.0114	0.0498
Ethane	10.8001	47.3044	9.6775	42.3875	99.9%	0.0205	0.0897
Propane	3.8442	16.8376	1.5209	6.6615	99.9%	0.0054	0.0235
i-Butane	0.5657	2.4778	0.1132	0.4958	99.9%	0.0007	0.0030
n-Butane	1.4765	6.4671	0.2378	1.0416	99.9%	0.0017	0.0075
i-Pentane	0.1701	0.7450	0.0217	0.0950	99.9%	0.0002	0.0008
n-Pentane	0.1778	0.7788	0.0174	0.0762	99.9%	0.0002	0.0009
n-Hexane	0.1386	0.6071	0.0067	0.0293	99.9%	0.0001	0.0006
Heptane	0.0086	0.0377	0.0004	0.0018	99.9%	0.0000	0.0000
Octane	0.0049	0.0215	0.0001	0.0004	99.9%	0.0000	0.0000
Benzene	4.5818	20.0683	0.1869	0.8186	99.9%	0.0048	0.0209
Toluene	6.3164	27.6658	0.1336	0.5852	99.9%	0.0065	0.0283
Ethylbenzene	0.2316	1.0144	0.0024	0.0105	99.9%	0.0002	0.0010
m-Xylene	1.2073	5.2880	0.0116	0.0508	99.9%	0.0012	0.0053
o-Xylene	0.2827	1.2382	0.0023	0.0101	99.9%	0.0003	0.0012
p-Xylene	0.9291	4.0695	0.0092	0.0403	99.9%	0.0009	0.0041
DEA	2.99E-15	0.0000	0.0000	0.0000	99.9%	0.0000	0.0000
MDEA	5.07E-11	0.0000	0.0000	0.0000	99.9%	0.0000	0.0000
Total VOC	**19.9353**	**87.3168**	**2.2642**	**9.9171**		**0.0222**	**0.0971**
Adjusted VOC [c]						**0.0244**	**0.1068**

PROJECT-AFFECTED AMINE UNITS POTENTIAL TO EMIT

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

	Plant 3 Amine Unit Uncontrolled Emissions [a]				Thermal Oxidizer	Plant 3 Amine Unit Total Potential to Emit (FIN: F-3117)	
	From Gas Treating		From Liquids Treating				
Component	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	DRE (%)	Hourly (lb/hr)	Annual (T/yr)
Nitrogen	0.0012	0.0053	0.0000	0.0000	0%	0.0012	0.0053
Carbon Dioxide	7,773	34,046	898	3,933	0%	8,671.00	37,979.00
Hydrogen Sulfide [b]	0.7500	3.2850	0.0000	0.0000	99.9%	0.0008	0.0033
Methane	11.2922	49.4598	0.0710	0.3110	99.9%	0.0114	0.0498
Ethane	10.8001	47.3044	9.6775	42.3875	99.9%	0.0205	0.0897
Propane	3.8442	16.8376	1.5209	6.6615	99.9%	0.0054	0.0235
i-Butane	0.5657	2.4778	0.1132	0.4958	99.9%	0.0007	0.0030
n-Butane	1.4765	6.4671	0.2378	1.0416	99.9%	0.0017	0.0075
i-Pentane	0.1701	0.7450	0.0217	0.0950	99.9%	0.0002	0.0008
n-Pentane	0.1778	0.7788	0.0174	0.0762	99.9%	0.0002	0.0009
n-Hexane	0.1386	0.6071	0.0067	0.0293	99.9%	0.0001	0.0006
Heptane	0.0086	0.0377	0.0004	0.0018	99.9%	0.0000	0.0000
Octane	0.0049	0.0215	0.0001	0.0004	99.9%	0.0000	0.0000
Benzene	4.5818	20.0683	0.1869	0.8186	99.9%	0.0048	0.0209
Toluene	6.3164	27.6658	0.1336	0.5852	99.9%	0.0065	0.0283
Ethylbenzene	0.2316	1.0144	0.0024	0.0105	99.9%	0.0002	0.0010
m-Xylene	1.2073	5.2880	0.0116	0.0508	99.9%	0.0012	0.0053
o-Xylene	0.2827	1.2382	0.0023	0.0101	99.9%	0.0003	0.0012
p-Xylene	0.9291	4.0695	0.0092	0.0403	99.9%	0.0009	0.0041
DEA	2.99E-15	0.0000	0.0000	0.0000	99.9%	0.0000	0.0000
MDEA	5.07E-11	0.0000	0.0000	0.0000	99.9%	0.0000	0.0000
Total VOC	**19.9353**	**87.3168**	**2.2642**	**9.9171**		**0.0222**	**0.0971**
Adjusted VOC [c]						**0.0244**	**0.1068**

	Plant 4 Amine Unit Uncontrolled Emissions [a]				Thermal Oxidizer	Plant 4 Amine Unit Total Potential to Emit (FIN: F-4117)	
	From Gas Treating		From Liquids Treating				
Component	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	DRE (%)	Hourly (lb/hr)	Annual (T/yr)
Nitrogen	0.0012	0.0053	0.0000	0.0000	0%	0.0012	0.0053
Carbon Dioxide	7,773	34,046	898	3,933	0%	8,671.00	37,979.00
Hydrogen Sulfide [b]	0.7500	3.2850	0.0000	0.0000	99.9%	0.0008	0.0033
Methane	11.2922	49.4598	0.0710	0.3110	99.9%	0.0114	0.0498
Ethane	10.8001	47.3044	9.6775	42.3875	99.9%	0.0205	0.0897
Propane	3.8442	16.8376	1.5209	6.6615	99.9%	0.0054	0.0235
i-Butane	0.5657	2.4778	0.1132	0.4958	99.9%	0.0007	0.0030
n-Butane	1.4765	6.4671	0.2378	1.0416	99.9%	0.0017	0.0075
i-Pentane	0.1701	0.7450	0.0217	0.0950	99.9%	0.0002	0.0008
n-Pentane	0.1778	0.7788	0.0174	0.0762	99.9%	0.0002	0.0009
n-Hexane	0.1386	0.6071	0.0067	0.0293	99.9%	0.0001	0.0006
Heptane	0.0086	0.0377	0.0004	0.0018	99.9%	0.0000	0.0000
Octane	0.0049	0.0215	0.0001	0.0004	99.9%	0.0000	0.0000
Benzene	4.5818	20.0683	0.1869	0.8186	99.9%	0.0048	0.0209
Toluene	6.3164	27.6658	0.1336	0.5852	99.9%	0.0065	0.0283
Ethylbenzene	0.2316	1.0144	0.0024	0.0105	99.9%	0.0002	0.0010
m-Xylene	1.2073	5.2880	0.0116	0.0508	99.9%	0.0012	0.0053
o-Xylene	0.2827	1.2382	0.0023	0.0101	99.9%	0.0003	0.0012
p-Xylene	0.9291	4.0695	0.0092	0.0403	99.9%	0.0009	0.0041
DEA	2.99E-15	0.0000	0.0000	0.0000	99.9%	0.0000	0.0000
MDEA	5.07E-11	0.0000	0.0000	0.0000	99.9%	0.0000	0.0000
Total VOC	**19.9353**	**87.3168**	**2.2642**	**9.9171**		**0.0222**	**0.0971**
Adjusted VOC [c]						**0.0244**	**0.1068**

a Emissions were calculated using ProMax v. 3.0 simulation program at 200 MMSCFD total capacity. Inputs to the simulation program were a representative inlet gas analysis.

b Amine inlet gas treater and product treater vent gas enters an absorber (scavenger) for H_2S removal prior to combustion in the thermal oxidizer. Uncontrolled H2S emissions are calculated as follows:

H_2S (lb/hr) = (H_2S conc., ppmv)/10^6 * (Scavenger Unit molar flow, lbmol/hr) * (34-lb H_2S/lbmol H_2S)

(103.5 lbmol H2S/10^6 lbmol gas) * (191.39 + 22.36 lbmol/hr) * (34-lb H2S/lbmol H2S) = 0.75 lb/hr

c Adjusted emissions were increased by 10 percent to allow for process gas variability. Emission calculations are based on a representative sample for current conditions and may change.

PROJECT-AFFECTED DEHY UNITS POTENTIAL TO EMIT

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Component	Uncontrolled Emissions [a] (FIN: F-1527) Plant 1 Waste Gas Hourly (lb/hr)	Annual (T/yr)	Thermal Oxidizer DRE (%)	Total Potential to Emit (FIN: F-1527) Hourly (lb/hr)	Annual (T/yr)
Nitrogen	0.0004	0.0018	0%	0.0004	0.0018
Carbon Dioxide	2.0971	9.1853	0%	2.0971	9.1853
Hydrogen Sulfide	0.0000	0.0000	99.9%	0.0000	0.0000
Methane	3.4932	15.3002	99.9%	0.0035	0.0153
Ethane	9.8277	43.0453	99.9%	0.0098	0.0430
Propane	15.3858	67.3898	99.9%	0.0154	0.0674
i-Butane	5.4865	24.0309	99.9%	0.0055	0.0240
n-Butane	12.6261	55.3023	99.9%	0.0126	0.0553
i-Pentane	7.8557	34.4080	99.9%	0.0079	0.0344
n-Pentane	6.9554	30.4647	99.9%	0.0070	0.0305
n-Hexane	10.8220	47.4004	99.9%	0.0108	0.0474
Heptane	4.3962	19.2554	99.9%	0.0044	0.0193
Octane	3.3357	14.6104	99.9%	0.0033	0.0146
Benzene	11.6850	51.1803	99.9%	0.0117	0.0512
Toluene	20.8035	91.1193	99.9%	0.0208	0.0911
Ethylbenzene	1.1973	5.2442	99.9%	0.0012	0.0052
m-Xylene	4.6370	20.3101	99.9%	0.0046	0.0203
o-Xylene	1.4309	6.2673	99.9%	0.0014	0.0063
p-Xylene	3.3444	14.6485	99.9%	0.0033	0.0146
TEG	0.0053	0.0232	99.9%	0.0000	0.0000
Total VOC	**109.9668**	**481.6548**		**0.1099**	**0.4816**
Adjusted VOC				**0.1209**	**0.5298**

Component	Uncontrolled Emissions [a] (FIN: F-2527) Plant 2 Waste Gas Hourly (lb/hr)	Annual (T/yr)	Thermal Oxidizer DRE (%)	Total Potential to Emit (FIN: F-2527) Hourly (lb/hr)	Annual (T/yr)
Nitrogen	0.0004	0.0018	0%	0.0004	0.0018
Carbon Dioxide	2.0971	9.1853	0%	2.0971	9.1853
Hydrogen Sulfide	0.0000	0.0000	99.9%	0.0000	0.0000
Methane	3.4932	15.3002	99.9%	0.0035	0.0153
Ethane	9.8277	43.0453	99.9%	0.0098	0.0430
Propane	15.3858	67.3898	99.9%	0.0154	0.0674
i-Butane	5.4865	24.0309	99.9%	0.0055	0.0240
n-Butane	12.6261	55.3023	99.9%	0.0126	0.0553
i-Pentane	7.8557	34.4080	99.9%	0.0079	0.0344
n-Pentane	6.9554	30.4647	99.9%	0.0070	0.0305
n-Hexane	10.8220	47.4004	99.9%	0.0108	0.0474
Heptane	4.3962	19.2554	99.9%	0.0044	0.0193
Octane	3.3357	14.6104	99.9%	0.0033	0.0146
Benzene	11.6850	51.1803	99.9%	0.0117	0.0512
Toluene	20.8035	91.1193	99.9%	0.0208	0.0911
Ethylbenzene	1.1973	5.2442	99.9%	0.0012	0.0052
m-Xylene	4.6370	20.3101	99.9%	0.0046	0.0203
o-Xylene	1.4309	6.2673	99.9%	0.0014	0.0063
p-Xylene	3.3444	14.6485	99.9%	0.0033	0.0146
TEG	0.0053	0.0232	99.9%	0.0000	0.0000
Total VOC	**109.9668**	**481.6548**		**0.1099**	**0.4816**
Adjusted VOC				**0.1209**	**0.5298**

PROJECT-AFFECTED DEHY UNITS POTENTIAL TO EMIT

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

	Uncontrolled Emissions [a] (FIN: F-3527) Plant 3 Waste Gas		Thermal Oxidizer	Total Potential to Emit (FIN: F-3527)	
Component	**Hourly (lb/hr)**	**Annual (T/yr)**	**DRE (%)**	**Hourly (lb/hr)**	**Annual (T/yr)**
Nitrogen	0.0004	0.0018	0%	0.0004	0.0018
Carbon Dioxide	2.0971	9.1853	0%	2.0971	9.1853
Hydrogen Sulfide	0.0000	0.0000	99.9%	0.0000	0.0000
Methane	3.4932	15.3002	99.9%	0.0035	0.0153
Ethane	9.8277	43.0453	99.9%	0.0098	0.0430
Propane	15.3858	67.3898	99.9%	0.0154	0.0674
i-Butane	5.4865	24.0309	99.9%	0.0055	0.0240
n-Butane	12.6261	55.3023	99.9%	0.0126	0.0553
i-Pentane	7.8557	34.4080	99.9%	0.0079	0.0344
n-Pentane	6.9554	30.4647	99.9%	0.0070	0.0305
n-Hexane	10.8220	47.4004	99.9%	0.0108	0.0474
Heptane	4.3962	19.2554	99.9%	0.0044	0.0193
Octane	3.3357	14.6104	99.9%	0.0033	0.0146
Benzene	11.6850	51.1803	99.9%	0.0117	0.0512
Toluene	20.8035	91.1193	99.9%	0.0208	0.0911
Ethylbenzene	1.1973	5.2442	99.9%	0.0012	0.0052
m-Xylene	4.6370	20.3101	99.9%	0.0046	0.0203
o-Xylene	1.4309	6.2673	99.9%	0.0014	0.0063
p-Xylene	3.3444	14.6485	99.9%	0.0033	0.0146
TEG	0.0053	0.0232	99.9%	0.0000	0.0000
Total VOC	**109.9668**	**481.6548**		**0.1099**	**0.4816**
Adjusted VOC				**0.1209**	**0.5298**

	Uncontrolled Emissions [a] (FIN: F-4527) Plant 4 Waste Gas		Thermal Oxidizer	Total Potential to Emit (FIN: F-4527)	
Component	**Hourly (lb/hr)**	**Annual (T/yr)**	**DRE (%)**	**Hourly (lb/hr)**	**Annual (T/yr)**
Nitrogen	0.0004	0.0018	0%	0.0004	0.0018
Carbon Dioxide	2.0971	9.1853	0%	2.0971	9.1853
Hydrogen Sulfide	0.0000	0.0000	99.9%	0.0000	0.0000
Methane	3.4932	15.3002	99.9%	0.0035	0.0153
Ethane	9.8277	43.0453	99.9%	0.0098	0.0430
Propane	15.3858	67.3898	99.9%	0.0154	0.0674
i-Butane	5.4865	24.0309	99.9%	0.0055	0.0240
n-Butane	12.6261	55.3023	99.9%	0.0126	0.0553
i-Pentane	7.8557	34.4080	99.9%	0.0079	0.0344
n-Pentane	6.9554	30.4647	99.9%	0.0070	0.0305
n-Hexane	10.8220	47.4004	99.9%	0.0108	0.0474
Heptane	4.3962	19.2554	99.9%	0.0044	0.0193
Octane	3.3357	14.6104	99.9%	0.0033	0.0146
Benzene	11.6850	51.1803	99.9%	0.0117	0.0512
Toluene	20.8035	91.1193	99.9%	0.0208	0.0911
Ethylbenzene	1.1973	5.2442	99.9%	0.0012	0.0052
m-Xylene	4.6370	20.3101	99.9%	0.0046	0.0203
o-Xylene	1.4309	6.2673	99.9%	0.0014	0.0063
p-Xylene	3.3444	14.6485	99.9%	0.0033	0.0146
TEG	0.0053	0.0232	99.9%	0.0000	0.0000
Total VOC	**109.9668**	**481.6548**		**0.1099**	**0.4816**
Adjusted VOC				**0.1209**	**0.5298**

a Emissions were calculated using ProMax v. 3.0 simulation program at 200 MMSCFD total capacity. Inputs to the simulation program were a representative inlet gas analysis.

b Adjusted emissions were increased by 10 percent to allow for process gas variability. Emission calculations are based on a representative sample for current conditions and may change.

THERMAL OXIDIZERS WASTE GAS POTENTIAL TO EMIT GREENHOUSE GASES

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Acid gas removal (AGR) and dehydrator vent emissions were calculated using the ProMax v. 3.0 simulation program as allowed by §98.233(d)(4) and §98.233(e)(1), respectively. ProMax uses the Peng-Robinson equation of state. Subpart W §98.233(d) inddicates that only CO2 emissions should be calculated for acid gas removal vents; however, methane (CH4) and combustion emissions are included for the site potential to emit.

CO_2 = (CO_2 emission from gas treating) + (CO_2 emission from liquid treating)
= ((7,773 lb/hr/unit) + (898.4 lb/hr/unit)) * (8760 hr/yr) / (2000 lb/ton)
= 37,981 ton/yr/unit

CO_2 = (CO_2 emission from dehy)
= ((2.10 lb/hr/unit) * (8760 hr/yr) / (2000 lb/ton)
= 9.19 ton/yr/unit

CH_4 = ((CH_4 emission from gas treating) + (CH_4 emission from liquid treating)) * (1 - 0.999 TO-1 control eff.)
= ((11.29 lb/hr/unit) + (0.07 lb/hr/unit)) * 0.001 * (8760 hr/yr) / (2000 lb/ton)
= 0.0498 ton/yr/unit

CH_4 = (CH_4 emission from dehy) * (1 - 0.999 TO-1 control eff.)
= (3.49 lb/hr/unit) * 0.001 * (8760 hr/yr) / (2000 lb/ton)
= 0.0153 ton/yr/unit

CO_2 Combustion Emissions

			Amine Unit		Glycol	Amine Unit		Glycol Unit	
	Number of	Molecular	Gas Treating	Liquid Treating	Unit	CO_2	CO_2	CO_2	CO_2
	Carbon	Weight	Mass Flow	Mass Flow	Mass Flow	Emission	Emission	Emission	Emission
Compound	Atoms	lb/lbmol	lb/hr/unit	lb/hr/unit	lb/hr/unit	lb/hr/unit	ton/yr/unit	lb/hr/unit	ton/yr/unit
Methane	1	16.04	11.2922	0.0710	3.4932	31.1397	136.3919	9.5728	41.9289
Ethane	2	30.07	10.8001	9.6775	9.8277	59.8679	262.2214	28.7321	125.8466
Propane	3	44.10	3.8442	1.5209	15.3858	16.0427	70.2670	46.0067	201.5093
i-Butane	4	58.12	0.5657	0.1132	5.4865	2.0538	8.9956	16.5977	72.6979
n-Butane	4	58.12	1.4765	0.2378	12.6261	5.1861	22.7151	38.1963	167.2998
i-Pentane	5	72.15	0.1701	0.0217	7.8557	0.5843	2.5592	23.9297	104.8121
n-Pentane	5	72.15	0.1778	0.0174	6.9554	0.5946	2.6043	21.1872	92.7999
n-Hexane	6	86.17	0.1386	0.0067	10.8220	0.4447	1.9478	33.1223	145.0757
Heptane	7	100.20	0.0086	0.0004	4.3962	0.0276	0.1209	13.4998	59.1291
Octane	8	114.22	0.0049	0.0001	3.3357	0.0154	0.0675	10.2696	44.9808
Benzene	6	78.11	4.5818	0.1869	11.6850	16.1014	70.5241	39.4540	172.8085
Toluene	7	92.13	6.3164	0.1336	20.8035	21.5414	94.3513	69.4787	304.3167
Ethylbenzene	8	106.17	0.2316	0.0024	1.1973	0.7750	3.3945	3.9656	17.3693
m-Xylene	8	106.17	1.2073	0.0116	4.6370	4.0371	17.6825	15.3583	67.2694
o-Xylene	8	106.17	0.2827	0.0023	1.4309	0.9440	4.1347	4.7393	20.7581
p-Xylene	8	106.17	0.9291	0.0092	3.3444	3.1078	13.6122	11.0771	48.5177
TEG	6	150.17	0.0000	0.0000	0.0053	0.0000	0.0000	0.0093	0.0407
TOTAL						162.4635	711.5900	385.1965	1687.1605

Sample calculation CO_2 combustion (using methane):

CO_2 = ((Gas treating flow, lb/hr)+(liquid treating flow, lb/hr))*(0.999 eff.)*(No. of C, lbmol C/lbmol CH4)*(44 lb CO2/lbmol C)/(Mw, lb CH4/lbmol CH4)
= ((11.29 lb/hr) + (0.07 lb/hr)) * (0.999) * (1 lbmol C/lbmol CH4) * (44 lb CO2/lbmol C) / (16.04 lb CH4/lbmol CH4)
= 31.1397 lb/hr/unit

CO_2 Annual = (31.1397 lb/hr/unit) * (8760 hr/yr) / (2000 lb/ton)
= 136.3919 ton/yr/unit

N_2O = Fuel * HHV * 0.0001 (Eq. W-40, §98.233(z)(6))

Where:

N_2O = Annual emissions from combustion in kilograms
Fuel = volume combusted, scfy
HHV = High heat value of fuel, MMBtu/scf

N2O = (0.0001 kg N2O/MMBtu) * ((Gas Treating scfy * Gas Treating HHV) + (Liquid Treating scfy * Liquid Treating HHV))
= (0.0001 kg N2O/MMBtu) * ((1.74 MMscfd) * (15.88 Btu/scf) + (0.20 MMscfd) * (35.00 Btu/scf)) * (365 days/yr) / (0.4536 kg/lb) / (2000 lb/ton)
= 1.40E-03 tons/yr/unit

N2O = 0.0001 * (dehy vent scfy) * HHV
= 0.0001 * (0.39 MMscfd) * (203.67 Btu/scf) * (365 days/yr) / (0.4536 kg/lb) / (2000 lb/ton)
= 3.17E-03 tons/yr/unit

THERMAL OXIDIZERS WASTE GAS POTENTIAL TO EMIT GREENHOUSE GASES

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Emission Summary:

EPN	FIN	Description	Uncombusted CO_2 (short T/yr)	Combustion CO_2 (short T/yr)	Uncombusted CH_4[a] (short T/yr)	Combustion N_2O (short T/yr)	CO_2e[b] (short T/yr)
TO-1	F-1117	Plant 1 Thermal Oxidizer - Amine Vent	37,981.00	711.59	0.05	0.0014	38,694.07
TO-1	F-1527	Plant 1 Thermal Oxidizer - Dehy Vent	9.19	1,687.16	0.02	0.0032	1,697.76
			37,990.19	2,398.75	0.07	0.0046	40,391.83
TO-2	F-2117	Plant 2 Thermal Oxidizer - Amine Vent	37,981.00	711.59	0.05	0.0014	38,694.07
TO-2	F-2527	Plant 2 Thermal Oxidizer - Dehy Vent	9.19	1,687.16	0.02	0.0032	1,697.76
			37,990.19	2,398.75	0.07	4.60E-03	40,391.83
TO-3	F-3117	Plant 3 Thermal Oxidizer - Amine Vent	37,981.00	711.59	0.05	0.0014	38,694.07
TO-3	F-3527	Plant 3 Thermal Oxidizer - Dehy Vent	9.19	1,687.16	0.02	0.0032	1,697.76
			37,990.19	2,398.75	0.07	4.60E-03	40,391.83
TO-4	F-4117	Plant 4 Thermal Oxidizer - Amine Vent	37,981.00	711.59	0.05	0.0014	38,694.07
TO-4	F-4527	Plant 4 Thermal Oxidizer - Dehy Vent	9.19	1,687.16	0.02	0.0032	1,697.76
			37,990.19	2,398.75	0.07	4.60E-03	40,391.83

a Emissions were calculated using ProMax v. 3.0 simulation program at 200 MMSCFD capacity per Plant. Inputs to the simulation program were a representative inlet gas analysis.

b CO_2e emissions are calculated as follows:

(37,981.00 T/yr Uncombusted CO2) + (711.59 T/yr Combustion CO2) + ((0.05 T/yr Methane) * 21) + ((0.0014 T/yr N2O) * 310) = 38,694.07 T/yr CO2e

PROJECT-AFFECTED BLOWDOWN VENTS POTENTIAL TO EMIT

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Description	C-1100A Blowdown (FIN GRP-BDSV)	C-1100B Blowdown (FIN GRP-BDSV)	C-1121A Blowdown (FIN GRP-BDSV)	C-1121B Blowdown (FIN GRP-BDSV)	C-1121C Blowdown (FIN GRP-BDSV)	C-161 Blowdown (FIN GRP-BDSV)	C-1611 Blowdown (FIN GRP-BDSV)	C-1612 Blowdown (FIN GRP-BDSV)
Number of Blowdowns per Year	72	72	72	72	72	12	12	12
Number of Blowdowns per Hour	1	1	1	1	1	1	1	1
Blowdown Volume per Event, scf	10,000	10,000	35,000	35,000	35,000	10,000	10,000	10,000
Gas Stream Specific Gravity	0.7210	0.7210	0.5622	0.5622	0.5622	1.5200	1.5200	1.5200
Gas Stream Density, lb/scf [a]	0.055	0.055	0.043	0.043	0.043	0.116	0.116	0.116
CO_2 Percentage in Gas Stream, wt%	2.150%	2.150%	0.81%	0.81%	0.81%	0%	0%	0%
Max Methane Percentage in Gas Stream, wt%	55.15%	55.15%	97.51%	97.51%	97.51%	0%	0%	0%
CO_2 Hourly Emission Rates (lb/hr): [b]	11.83	11.83	12.19	12.19	12.19	0.00	0.00	0.00
CO_2 Annual Emission Rates (T/yr): [c]	0.43	0.43	0.44	0.44	0.44	0.00	0.00	0.00
Methane Hourly Emission Rates (lb/hr): [b]	303.33	303.33	1,467.53	1,467.53	1,467.53	0.00	0.00	0.00
Methane Annual Emission Rates (T/yr): [c]	10.92	10.92	52.83	52.83	52.83	0.00	0.00	0.00

Description	C-2100A Blowdown (FIN GRP-BDSV)	C-2100B Blowdown (FIN GRP-BDSV)	C-2121A Blowdown (FIN GRP-BDSV)	C-2121B Blowdown (FIN GRP-BDSV)	C-2121C Blowdown (FIN GRP-BDSV)	C-162 Blowdown (FIN GRP-BDSV)	C-1621 Blowdown (FIN GRP-BDSV)	C-1622 Blowdown (FIN GRP-BDSV)
Number of Blowdowns per Year	72	72	72	72	72	12	12	12
Number of Blowdowns per Hour	1	1	1	1	1	1	1	1
Blowdown Volume per Event, scf	10,000	10,000	35,000	35,000	35,000	10,000	10,000	10,000
Gas Stream Specific Gravity	0.7210	0.7210	0.5622	0.5622	0.5622	1.5200	1.5200	1.5200
Gas Stream Density, lb/scf [a]	0.055	0.055	0.043	0.043	0.043	0.116	0.116	0.116
CO_2 Percentage in Gas Stream, wt%	2.150%	2.150%	0.81%	0.81%	0.81%	0%	0%	0%
Max Methane Percentage in Gas Stream, wt%	55.15%	55.15%	97.51%	97.51%	97.51%	0%	0%	0%
CO_2 Hourly Emission Rates (lb/hr): [b]	11.83	11.83	12.19	12.19	12.19	0.00	0.00	0.00
CO_2 Annual Emission Rates (T/yr): [c]	0.43	0.43	0.44	0.44	0.44	0.00	0.00	0.00
Methane Hourly Emission Rates (lb/hr): [b]	303.33	303.33	1,467.53	1,467.53	1,467.53	0.00	0.00	0.00
Methane Annual Emission Rates (T/yr): [c]	10.92	10.92	52.83	52.83	52.83	0.00	0.00	0.00

PROJECT-AFFECTED BLOWDOWN VENTS POTENTIAL TO EMIT

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Description	C-3100A Blowdown (FIN GRP-BDSV)	C-3100B Blowdown (FIN GRP-BDSV)	C-3121A Blowdown (FIN GRP-BDSV)	C-3121B Blowdown (FIN GRP-BDSV)	C-3121C Blowdown (FIN GRP-BDSV)	C-163 Blowdown (FIN GRP-BDSV)	C-1631 Blowdown (FIN GRP-BDSV)	C-1632 Blowdown (FIN GRP-BDSV)
Number of Blowdowns per Year	72	72	72	72	72	12	12	12
Number of Blowdowns per Hour	1	1	1	1	1	1	1	1
Blowdown Volume per Event, scf	10,000	10,000	35,000	35,000	35,000	10,000	10,000	10,000
Gas Stream Specific Gravity	0.7210	0.7210	0.5622	0.5622	0.5622	1.5200	1.5200	1.5200
Gas Stream Density, lb/scf [a]	0.055	0.055	0.043	0.043	0.043	0.116	0.116	0.116
CO_2 Percentage in Gas Stream, wt%	2.150%	2.150%	0.81%	0.81%	0.81%	0%	0%	0%
Max Methane Percentage in Gas Stream, wt%	55.15%	55.15%	97.51%	97.51%	97.51%	0%	0%	0%
CO_2 Hourly Emission Rates (lb/hr): [b]	11.83	11.83	12.19	12.19	12.19	0.00	0.00	0.00
CO_2 Annual Emission Rates (T/yr): [c]	0.43	0.43	0.44	0.44	0.44	0.00	0.00	0.00
Methane Hourly Emission Rates (lb/hr): [b]	303.33	303.33	1,467.53	1,467.53	1,467.53	0.00	0.00	0.00
Methane Annual Emission Rates (T/yr): [c]	10.92	10.92	52.83	52.83	52.83	0.00	0.00	0.00

Description	C-4100A Blowdown (FIN GRP-BDSV)	C-4100B Blowdown (FIN GRP-BDSV)	C-4121A Blowdown (FIN GRP-BDSV)	C-4121B Blowdown (FIN GRP-BDSV)	C-4121C Blowdown (FIN GRP-BDSV)	C-164 Blowdown (FIN GRP-BDSV)	C-1641 Blowdown (FIN GRP-BDSV)	C-1642 Blowdown (FIN GRP-BDSV)
Number of Blowdowns per Year	72	72	72	72	72	12	12	12
Number of Blowdowns per Hour	1	1	1	1	1	1	1	1
Blowdown Volume per Event, scf	10,000	10,000	35,000	35,000	35,000	10,000	10,000	10,000
Gas Stream Specific Gravity	0.7210	0.7210	0.5622	0.5622	0.5622	1.5200	1.5200	1.5200
Gas Stream Density, lb/scf [a]	0.055	0.055	0.043	0.043	0.043	0.116	0.116	0.116
CO_2 Percentage in Gas Stream, wt%	2.150%	2.150%	0.81%	0.81%	0.81%	0%	0%	0%
Max Methane Percentage in Gas Stream, wt%	55.15%	55.15%	97.51%	97.51%	97.51%	0%	0%	0%
CO_2 Hourly Emission Rates (lb/hr): [b]	11.83	11.83	12.19	12.19	12.19	0.00	0.00	0.00
CO_2 Annual Emission Rates (T/yr): [c]	0.43	0.43	0.44	0.44	0.44	0.00	0.00	0.00
Methane Hourly Emission Rates (lb/hr): [b]	303.33	303.33	1,467.53	1,467.53	1,467.53	0.00	0.00	0.00
Methane Annual Emission Rates (T/yr): [c]	10.92	10.92	52.83	52.83	52.83	0.00	0.00	0.00

Total Estimated CO_2 Sent to Plant Flare (Tyr):	**8.72**
Total Estimated Methane Sent to Plant Flare (Tyr):	**721.32**

[a] Gas stream density is calculated as follows:

(28.96 lb/mole) / (379 scf/mole) * (0.7210) = 0.055 lb/scf

[b] Hourly blowdown emissions are calculated as follows:

(1 blowdown/hr) * (10,000 scf/blowdown) * (0.055 lb/scf) * (55.15 %)= 303.33 lb/hr

[c] Annual blowdown emissions are calculated as follows:

(72 blowdowns/yr) * (10,000 scf/blowdown) * (0.055 lb/scf) * (55.15 %) / (2,000 lb/T) = 10.92 T/yr

PROJECT-AFFECTED STARTER VENTS POTENTIAL TO EMIT

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Description	C-1100A Starter Vent (FIN GRP-BDSV)	C-1100B Starter Vent (FIN GRP-BDSV)	C-1121A Starter Vent (FIN GRP-BDSV)	C-1121B Starter Vent (FIN GRP-BDSV)	C-1121C Starter Vent (FIN GRP-BDSV)
Number of Starter Vents per Year	200	200	200	200	200
Number of Starter Vents per Hour	1	1	1	1	1
Starter Vent Volume per Event, scf	1,000	1,000	1,000	1,000	1,000
Gas Stream Specific Gravity	0.5622	0.5622	0.5622	0.5622	0.5622
Gas Stream Density, lb/scf [a]	0.043	0.043	0.043	0.043	0.043
CO_2 Percentage in Gas Stream, wt%	0.81%	0.81%	0.81%	0.81%	0.81%
Methane Percentage in Gas Stream, wt%	97.51%	97.51%	97.51%	97.51%	97.51%
CO_2 Hourly Emission Rates (lb/hr): [b]	0.35	0.35	0.35	0.35	0.35
CO_2 Annual Emission Rates (T/yr): [c]	0.03	0.03	0.03	0.03	0.03
Methane Hourly Emission Rates (lb/hr): [b]	41.93	41.93	41.93	41.93	41.93
Methane Annual Emission Rates (T/yr): [c]	4.19	4.19	4.19	4.19	4.19

Description	C-2100A Starter Vent (FIN GRP-BDSV)	C-2100B Starter Vent (FIN GRP-BDSV)	C-2121A Starter Vent (FIN GRP-BDSV)	C-2121B Starter Vent (FIN GRP-BDSV)	C-2121C Starter Vent (FIN GRP-BDSV)
Number of Starter Vents per Year	200	200	200	200	200
Number of Starter Vents per Hour	1	1	1	1	1
Starter Vent Volume per Event, scf	1,000	1,000	1,000	1,000	1,000
Gas Stream Specific Gravity	0.5622	0.5622	0.5622	0.5622	0.5622
Gas Stream Density, lb/scf [a]	0.043	0.043	0.043	0.043	0.043
CO_2 Percentage in Gas Stream, wt%	0.81%	0.81%	0.81%	0.81%	0.81%
Methane Percentage in Gas Stream, wt%	97.51%	97.51%	97.51%	97.51%	97.51%
CO_2 Hourly Emission Rates (lb/hr): [b]	0.35	0.35	0.35	0.35	0.35
CO_2 Annual Emission Rates (T/yr): [c]	0.03	0.03	0.03	0.03	0.03
Methane Hourly Emission Rates (lb/hr): [b]	41.93	41.93	41.93	41.93	41.93
Methane Annual Emission Rates (T/yr): [c]	4.19	4.19	4.19	4.19	4.19

PROJECT-AFFECTED STARTER VENTS POTENTIAL TO EMIT

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Description	C-3100A Starter Vent (FIN GRP-BDSV)	C-3100B Starter Vent (FIN GRP-BDSV)	C-3121A Starter Vent (FIN GRP-BDSV)	C-3121B Starter Vent (FIN GRP-BDSV)	C-3121C Starter Vent (FIN GRP-BDSV)
Number of Starter Vents per Year	200	200	200	200	200
Number of Starter Vents per Hour	1	1	1	1	1
Starter Vent Volume per Event, scf	1,000	1,000	1,000	1,000	1,000
Gas Stream Specific Gravity	0.5622	0.5622	0.5622	0.5622	0.5622
Gas Stream Density, lb/scf [a]	0.043	0.043	0.043	0.043	0.043
CO_2 Percentage in Gas Stream, wt%	0.81%	0.81%	0.81%	0.81%	0.81%
Methane Percentage in Gas Stream, wt%	97.51%	97.51%	97.51%	97.51%	97.51%
CO_2 Hourly Emission Rates (lb/hr): [b]	0.35	0.35	0.35	0.35	0.35
CO_2 Annual Emission Rates (T/yr): [c]	0.03	0.03	0.03	0.03	0.03
Methane Hourly Emission Rates (lb/hr): [b]	41.93	41.93	41.93	41.93	41.93
Methane Annual Emission Rates (T/yr): [c]	4.19	4.19	4.19	4.19	4.19

Description	C-4100A Starter Vent (FIN GRP-BDSV)	C-4100B Starter Vent (FIN GRP-BDSV)	C-4121A Starter Vent (FIN GRP-BDSV)	C-4121B Starter Vent (FIN GRP-BDSV)	C-4121C Starter Vent (FIN GRP-BDSV)
Number of Starter Vents per Year	200	200	200	200	200
Number of Starter Vents per Hour	1	1	1	1	1
Starter Vent Volume per Event, scf	1,000	1,000	1,000	1,000	1,000
Gas Stream Specific Gravity	0.5622	0.5622	0.5622	0.5622	0.5622
Gas Stream Density, lb/scf [a]	0.043	0.043	0.043	0.043	0.043
CO_2 Percentage in Gas Stream, wt%	0.81%	0.81%	0.81%	0.81%	0.81%
Methane Percentage in Gas Stream, wt%	97.51%	97.51%	97.51%	97.51%	97.51%
CO_2 Hourly Emission Rates (lb/hr): [b]	0.35	0.35	0.35	0.35	0.35
CO_2 Annual Emission Rates (T/yr): [c]	0.03	0.03	0.03	0.03	0.03
Methane Hourly Emission Rates (lb/hr): [b]	41.93	41.93	41.93	41.93	41.93
Methane Annual Emission Rates (T/yr): [c]	4.19	4.19	4.19	4.19	4.19
Total Estimated CO_2 Sent to Plant Flare (Tyr):		**0.60**			
Total Estimated Methane Sent to Plant Flare (T/yr):		**83.80**			

[a] Gas stream density is calculated as follows:

(28.96 lb/mole) / (379 scf/mole) * (0.5622) = 0.043 lb/scf

[b] Hourly blowdown emissions are calculated as follows:

(1 blowdown/hr) * (1,000 scf/blowdown) * (0.043 lb/scf) * (97.51 %)= 41.93 lb/hr

[c] Annual blowdown emissions are calculated as follows:

(200 blowdowns/yr) * (1,000 scf/blowdown) * (0.043 lb/scf) * (97.51 %) / (2,000 lb/T) = 4.19 T/yr

FLARE POTENTIAL TO EMIT GREENHOUSE GASES

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Uncombusted CO_2 and CH_4 Emissions

The un-combusted emissions for CO_2 and CH_4 were calculated for the Plant Flare (FS-800) only. Stabilized condensate does not contain CH4 or CO2, so emissions were not calculated for the loading flare (FL-FLARE).

$E_{a,CH4}$ (un-combusted) = V_a *(1-η)*X_{CH4} (Eq. W-19 in 98.233(n)(4))

$E_{a,CO2}$ (un-combusted) = V_a * X_{CO2} (Eq. W-20 in 98.233(n)(4))

Where:

$E_{a,CH4}$ (un-combusted) = Contribution of annual un-combusted CH4 emissions from flare in cubic feet.
$E_{a,CO2}$ (un-combusted) = Contribution of annual un-combusted CO2 emissions from flare in cubic feet.
V_a = Volume of vent gas cubic feet per year.
η = Fraction of gas combusted (default = 0.98).
X_{CH4} = Mole fraction of CH_4 in vent gas
X_{CO2} = Mole fraction of CO_2 in vent gas

Rather than using the molar flowrate (Va * X) entering the flare, the mass flowrate of methand and CO2 was calculated through mass balance for blowdown and starter vents and is substituted into each equation to calculate the mass flowrates from the flare. See the blowdown and starter vent emission calculations for more information.

CH_4 = ((CH_4 emission from starter vents, T/yr) + (CH_4 emission from blowdown vents, T/yr)) * (1 - 0.98 control eff.)
= ((83.80 T/yr from starter vents) + (721.32 T/yr from blowdown vents)) * 0.02
= $\boxed{16.10 \text{ T/yr}}$

CO_2 = (CO_2 emission from starter vents, T/yr) + (CO_2 emission from blowdown vents, T/yr)
= (0.60 T/yr) + (8.72 T/yr)
= $\boxed{9.32 \text{ T/yr}}$

Combustion CO_2 Emissions

$E_{a,CO2}$ (combusted) = Σ η*V_a*Y_j*R_j (Eq. W-21 in 98.233(n)(4))

Where:

$E_{a,CO2}$ (combusted) = Contribution of annual combusted CO2 emissions from thermal oxidizer in cubic feet.
Y_j = Mole fraction of gas hydrocarbon constituents j.
R_j = Number of carbon atoms in the gas hydrocarbon constituent j.

Compound	R Number of Carbon Atoms	Y Stream Mole Fractions			Carbon Concentration to Flare [b]		
		Propane	Inlet Gas	Condensate [a]	Propane Compressors lbmol	Gas Compressors lbmol	Condensate Loading lbmol
Methane	1	0	0.7680	0	0.0000	0.7680	0.0000
Ethane	2	0	0.1330	0.0013	0.0000	0.2660	0.0026
Propane	3	1	0.0526	0.0032	3.0000	0.1578	0.0096
i-Butane	4	0	0.0107	0.0024	0.0000	0.0428	0.0096
n-Butane	4	0	0.0138	0.0095	0.0000	0.0552	0.0380
i-Pentane	5	0	0.0040	0.0188	0.0000	0.0200	0.0940
n-Pentane	5	0	0.0028	0.0272	0.0000	0.0140	0.1360
n-Hexane	6	0	0.0024	0.0542	0.0000	0.0144	0.3252
Other Hexanes	6	0	0.0000	0.0574	0.0000	0.0000	0.3444
Heptane	7	0	0.0006	0.2598	0.0000	0.0042	1.8186
Octane	8	0	0.0004	0.3043	0.0000	0.0032	2.4344
Nonane	9	0	0.0000	0.1415	0.0000	0.0000	1.2735
Benzene	6	0	0.0001	0.0089	0.0000	0.0006	0.0534
Toluene	7	0	0.0002	0.0618	0.0000	0.0014	0.4326
Ethylbenzene	8	0	0.0010	0.0029	0.0000	0.0080	0.0232
m-Xylene	8	0	0.0040	0.0234	0.0000	0.0320	0.1872
o-Xylene	8	0	0.0010	0.0059	0.0000	0.0080	0.0472
p-Xylene	8	0	0.0030	0.0176	0.0000	0.0240	0.1408
TOTAL					3.0000	1.4196	7.3703

[a] The condensate vapor phase concentrations are unknown, so the liquid concentrations were used for emission calculations.

[b] Sample calcualtion using methane:

Carbon Concentration = (R, lbmol carbon/lbmol CH_4) * (Y, lbmol CH_4/lbmol gas)
= (1.0 lbmol C/lbmol CH4) * (0.7680 lbmol CH4/lbmol gas) = 0.7680 lbmol C/lbmol gas from CH4

$E_{a,CO2}$ (combusted C3) = (1,440,000 scfy C3 BD vent) * (3.0 lbmol C/lbmol gas)) * (0.98) = 4,233,600 scfy Carbon
$E_{a,CO2}$ (combusted inlet) = (36,000,000 scfy inlet BD vent) * 4,000,000 scfy inlet SV) * (1.4 lbmol C/lbmol gas)) * (0.98) = 55,648,320 scfy Carbon
$E_{a,CO2}$ (combusted load) = (15,330,000 gal/yr Condensate) * (0.1337 ft3/gal) * (7.4 lbmol C/lbmol gas)) * (0.98) = 14,804,195 scfy Carbon

BD and SV CO_2 (T/yr) = (4,233,600 + 55,648,320 scfy Carbon) * (14.7 psia) / (10.73 psia-ft3/lbmol-°R) / (520 °R) * (44 lb CO2/lbmol C) / (2,000 lb/ton)
= $\boxed{3{,}471 \text{ ton/yr } CO_2}$

Loading CO_2 (T/yr) = (14,804,195 acfy Carbon) * (14.7 psia) / (10.73 psia-ft3/lbmol-°R) / (530 °R) * (44 lb CO2/lbmol C) / (2,000 lb/ton)
= $\boxed{842 \text{ ton/yr } CO_2}$

FLARE POTENTIAL TO EMIT GREENHOUSE GASES

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Combustion N_2O Emissions

N_2O = Fuel * HHV * 0.0001 (Eq. W-40, §98.233(z)(6))

Where:

N_2O = Annual emissions from combustion in kilograms

Fuel = volume combusted, scfy

HHV = High heat value of fuel, MMBtu/scf

BD and SV N2O = (0.0001 kg N2O/MMBtu) * ((Propane, scfy * Propane HHV) + (Inlet Gas scfy * Inlet Gas HHV)) / (0.4536 kg/lb) / (2,000 lb/ton)

= (0.0001 kg N2O/10^6 Btu) * ((1440000.00 scfy) * (2,519 Btu/scf) + (40,000,000 scfy) * (1269 Btu/scf)) / (0.4536 kg/lb) / (2000 lb/ton)

= 0.0059 T/yr

Loading N2O = (0.0001 kg N2O/MMBtu) * (Loading, scfy * 3,000 Btu/scf) / (0.4536 kg/lb) / (2,000 lb/ton)

= (0.0001 kg N2O/10^6 Btu) * (2,049,621 acfy) * (3,000 Btu/scf) / (0.4536 kg/lb) / (2000 lb/ton)

= 0.0007 T/yr

Emission Summary:

EPN	FIN	Description	Uncombusted CO_2 (short T/yr)	Combustion CO_2 (short T/yr)	Uncombusted CH_4 (short T/yr)	Combustion N_2O (short T/yr)	CO_2e[a] (short T/yr)
FS-800	GRP-BDSV	Plant Flare BD and SV emissions	9.32	3,471.00	16.10	0.0059	3,820.25
TL-FLARE	C-LOAD	Stabilized Condensate Loading	0	842.00	0	0.0007	842.22

[a] CO_2e emissions are calculated as follows:

(9.32 T/yr Uncombusted CO2) + (3,471.00 T/yr Combustion CO2) + ((16.10 T/yr Methane) * 21) + ((0.0059 T/yr N2O) * 310) = 3,820.25 T/yr CO2e

EXISTING UNMODIFIED STABILIZATION UNIT PIPING FUGITIVES POTENTIAL TO EMIT

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Component	Number of Components	Emission Factors [a] (lb/hr-component)	Operating Hours (hr/yr)	Maximum Methane (wt%)	Maximum CO_2 (wt%)	Reduction Credit [a] (%)	PTE Methane Hourly [b] (lb/hr)	PTE Methane Annual [c] (T/yr)	PTE CO_2 Hourly [b] (lb/hr)	PTE CO_2 Annual [c] (T/yr)
Valves										
Gas Streams (Inlet)	105	0.00992	8,760	55%	2%	97%	0.0172	0.0753	0.0006	0.0027
Gas Streams (Residue)	0	0.00992	8,760	98%	1%	97%	0.0000	0.0000	0.0000	0.0000
Gas Streams (Processing)	0	0.00992	8,760	55%	2%	97%	0.0000	0.0000	0.0000	0.0000
Light Liquid Streams	263	0.0055	8,760	0%	0%	97%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	0	0.000216	8,760	0%	0%	97%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	0	0.0000185	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Relief Valves										
Gas Streams (Inlet)	10	0.0194	8,760	55%	2%	97%	0.0032	0.0140	0.0001	0.0005
Gas Streams (Residue)	0	0.0194	8,760	98%	1%	97%	0.0000	0.0000	0.0000	0.0000
Gas Streams (Processing)	0	0.0194	8,760	55%	2%	97%	0.0000	0.0000	0.0000	0.0000
Light Liquid Streams	0	0.0165	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	0	0.0309	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	0	0.0000683	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Compressor Seals										
Gas Streams (Inlet)	0	0.0194	8,760	55%	2%	95%	0.0000	0.0000	0.0000	0.0000
Gas Streams (Residue)	0	0.0194	8,760	98%	1%	95%	0.0000	0.0000	0.0000	0.0000
Gas Streams (Processing)	0	0.0194	8,760	55%	2%	95%	0.0000	0.0000	0.0000	0.0000
Light Liquid Streams	0	0.0165	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	0	0.0309	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	0	0.0000683	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Pump Seals										
Gas Streams (Inlet)	0	0.00529	8,760	55%	2%	0%	0.0000	0.0000	0.0000	0.0000
Gas Streams (Residue)	0	0.00529	8,760	98%	1%	0%	0.0000	0.0000	0.0000	0.0000
Gas Streams (Processing)	0	0.00529	8,760	55%	2%	0%	0.0000	0.0000	0.0000	0.0000
Light Liquid Streams	5	0.02866	8,760	0%	0%	93%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	0	0.000052	8,760	0%	0%	93%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	0	0.00113	8,760	0%	0%	0%	0.0000	0.0000	0.0000	0.0000
Flanges										
Gas Streams (Inlet)	263	0.00086	8,760	55%	2%	75%	0.0311	0.1362	0.0011	0.0050
Gas Streams (Residue)	0	0.00086	8,760	98%	1%	75%	0.0000	0.0000	0.0000	0.0000
Gas Streams (Processing)	0	0.00086	8,760	55%	2%	75%	0.0000	0.0000	0.0000	0.0000
Light Liquid Streams	658	0.000243	8,760	0%	0%	75%	0.0000	0.0000	0.0000	0.0000
Water/Light Liquid	0	0.000006	8,760	0%	0%	75%	0.0000	0.0000	0.0000	0.0000
Heavy Liquid	0	0.00000086	8,760	0%	0%	30%	0.0000	0.0000	0.0000	0.0000
						Gas Streams (Inlet):	**0.0515**	**0.2255**	**0.0018**	**0.0082**
						Gas Streams (Residue):	**0.0000**	**0.0000**	**0.0000**	**0.0000**
						Gas Streams (Processing):	**0.0000**	**0.0000**	**0.0000**	**0.0000**
						Light Liquid Streams:	**0.0000**	**0.0000**	**0.0000**	**0.0000**
						Water/Light Liquid:	**0.0000**	**0.0000**	**0.0000**	**0.0000**
						Heavy Liquid:	**0.0000**	**0.0000**	**0.0000**	**0.0000**
						TOTALS:	**0.05**	**0.23**	**0.00**	**0.01**

[a] Fugitive Emission Factors and Reduction Credits are per TCEQ Technical Guidance Document for Equipment Leak Fugitives, dated October 2000. The emission factors are for total hydrocarbon. Reduction credit is from 28LAER.

[b] Hourly Methane and CO_2 emission rates are calculated as follows:
(105 components) * (0.00992 lb/hr-component) * (55% Methane) * (100% - 97% reduction credit) = 0.0172 lb/hr

[c] Annual Methane and CO_2 emission rates are calculated as follows:
(105 components) * (0.00992 lb/hr-component) * (8,760 hr/yr) * (55% Methane) * (100% - 97% reduction credit) / (2,000 lb/T) = 0.0753 T/yr

SITE DATA

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

Stream Compositions:

	Stream 1		Stream 2		Stream 3		Stream 4	
	Fuel/Residue		Inlet Gas		Liquid		Propane	
Component	mole %	wgt. %	mole %	wgt. %	mole %	wgt %	mole %	wgt %
Water	0.1000%	0.11%	0.0000%	0.000%	0.0000%	0.00%	0.0000%	0.00%
Nitrogen	0.1000%	0.17%	0.0660%	0.080%	0.0000%	0.00%	0.0000%	0.00%
Carbon Dioxide	0.3000%	0.81%	1.0900%	2.150%	0.0000%	0.00%	0.0000%	0.00%
Oxygen	0.0000%	0.00%	0.0000%	0.000%	0.0000%	0.00%	0.0000%	0.00%
Hydrogen Sulfide	0.0004%	0.001%	0.0000%	0.000%	0.0000%	0.00%	0.0000%	0.00%
Methane	98.9000%	97.51%	76.8000%	55.150%	0.0000%	0.00%	0.0000%	0.00%
Ethane	0.7000%	1.29%	13.3000%	17.900%	0.1330%	0.04%	0.0000%	0.00%
Propane	0.0080%	0.02%	5.2600%	10.390%	0.3240%	0.14%	100.00%	100.00%
I-Butane	0.0000%	0.00%	1.0700%	2.780%	0.2390%	0.13%	0.0000%	0.00%
N-Butane	0.0000%	0.00%	1.3800%	3.590%	0.9460%	0.53%	0.0000%	0.00%
I-Pentane	0.0000%	0.00%	0.3960%	1.280%	1.8780%	1.30%	0.0000%	0.00%
N-Pentane	0.0000%	0.00%	0.2770%	0.900%	2.7180%	1.88%	0.0000%	0.00%
n-Hexane	0.0000%	0.00%	0.2390%	0.920%	5.4200%	4.47%	0.0000%	0.00%
Other Hexanes	0.0000%	0.00%	0.0000%	0.000%	5.7420%	4.74%	0.0000%	0.00%
Heptane	0.0000%	0.00%	0.0600%	0.270%	25.9830%	24.93%	0.0000%	0.00%
Octane	0.0000%	0.00%	0.0420%	0.210%	30.4290%	33.29%	0.0000%	0.00%
Nonane	0.0000%	0.00%	0.0000%	0.000%	14.1510%	17.38%	0.0000%	0.00%
Benzene	0.0000%	0.00%	0.0100%	0.040%	0.8850%	0.66%	0.0000%	0.00%
Toluene	0.0150%	0.09%	0.0150%	0.060%	6.1810%	5.45%	0.0000%	0.00%
Ethylbenzene	0.0000%	0.00%	0.1000%	0.470%	0.2930%	0.30%	0.0000%	0.00%
m-Xylene	0.0000%	0.00%	0.4000%	1.900%	2.3400%	2.38%	0.0000%	0.00%
o-Xylene	0.0000%	0.00%	0.1000%	0.470%	0.5850%	0.59%	0.0000%	0.00%
p-Xylene	0.0000%	0.00%	0.3000%	1.420%	1.755%	1.78%	0.0000%	0.00%
Totals	100.1%	100.0%	100.9%	100.0%	100.0%	100.0%	100.0%	100.0%
Totals (C3+)	0.02%	0.11%	9.6%	24.7%	99.87%	99.95%		100.00%
VOC max		2.00%		20.00%		100.00%		100.00%
Specific Gravity	0.5622		0.7210		3.1979		1.5200	
Mw	16.3		22.3		104.4		44.1	

The hexane plus portion of the gas streams are assumed to be n-hexane.

Fuel Gas Higher Heating Value	1,011	Btu/scf
Fuel Gas Lower Heating Value	911	Btu/scf

APPENDIX C
VENDOR EQUIPMENT SPECIFICATIONS

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

G3606

GAS COMPRESSION APPLICATION

GAS ENGINE SITE SPECIFIC TECHNICAL DATA
Jackson Co.

ENGINE SPEED (rpm):	1000
COMPRESSION RATIO:	9:1
AFTERCOOLER WATER INLET (°F):	130
JACKET WATER OUTLET (°F):	190
COOLING SYSTEM:	JW, OC+AC
IGNITION SYSTEM:	CIS/ADEM3
EXHAUST MANIFOLD:	DRY
COMBUSTION:	Low Emission
NOx EMISSION LEVEL (g/bhp-hr NOx):	0.5

FUEL SYSTEM:	GAV
	WITH AIR FUEL RATIO CONTROL

SITE CONDITIONS:

FUEL:	Nat Gas
FUEL PRESSURE RANGE(psig):	42.8-47.0
FUEL METHANE NUMBER:	84.8
FUEL LHV (Btu/scf):	905
ALTITUDE(ft):	300
MAXIMUM INLET AIR TEMPERATURE(°F):	105
NAMEPLATE RATING:	1775 bhp@1000rpm

			MAXIMUM RATING	SITE RATING AT MAXIMUM INLET AIR TEMPERATURE		
RATING	**NOTES**	**LOAD**	**100%**	**100%**	**75%**	**50%**
ENGINE POWER	(1)	bhp	1775	1775	1331	888
INLET AIR TEMPERATURE		°F	106	105	105	105
ENGINE DATA						
FUEL CONSUMPTION (LHV)	(2)	Btu/bhp-hr	6811	6811	7102	7620
FUEL CONSUMPTION (HHV)	(2)	Btu/bhp-hr	7555	7555	7878	8452
AIR FLOW	(3)(4)	lb/hr	20778	20778	16185	10901
AIR FLOW WET (77°F, 14.7 psia)	(3)(4)	scfm	4686	4686	3650	2459
INLET MANIFOLD PRESSURE	(5)	in Hg(abs)	74.3	74.3	57.9	41.2
EXHAUST STACK TEMPERATURE	(6)	°F	847	847	870	937
EXHAUST GAS FLOW (@ stack temp, 14.5 psia)	(7)(4)	ft3/min	12146	12146	9630	6833
EXHAUST GAS MASS FLOW	(7)(4)	lb/hr	21389	21389	16662	11243
EMISSIONS DATA						
NOx (as NO2)	(8)	g/bhp-hr	0.50	0.50	0.50	0.50
CO	(8)	g/bhp-hr	2.75	2.75	2.75	2.75
THC (mol. wt. of 15.84)	(8)	g/bhp-hr	6.31	6.31	6.52	6.78
NMHC (mol. wt. of 15.84)	(8)	g/bhp-hr	0.95	0.95	0.98	1.02
NMNEHC (VOCs) (mol. wt. of 15.84)	(8)(9)	g/bhp-hr	0.63	0.63	0.65	0.68
HCHO (Formaldehyde)	(8)	g/bhp-hr	0.26	0.26	0.28	0.31
CO2	(8)	g/bhp-hr	442	442	461	495
EXHAUST OXYGEN	(10)	% DRY	12.8	12.8	12.1	11.1
HEAT REJECTION						
HEAT REJ. TO JACKET WATER (JW)	(11)	Btu/min	17875	17875	15467	12926
HEAT REJ. TO ATMOSPHERE	(11)	Btu/min	7052	7052	6619	6199
HEAT REJ. TO LUBE OIL (OC)	(11)	Btu/min	9067	9067	8667	8453
HEAT REJ. TO AFTERCOOLER (AC)	(11)(12)	Btu/min	17078	17078	9370	1822

HEAT EXCHANGER SIZING CRITERIA			
TOTAL JACKET WATER CIRCUIT (JW)	(12)	Btu/min	19663
TOTAL AFTERCOOLER CIRCUIT (OC+AC)	(12)(13)	Btu/min	28813
A cooling system safety factor of 0% has been added to the heat exchanger sizing criteria.			

CONDITIONS AND DEFINITIONS

Engine rating obtained and presented in accordance with ISO 3046/1, adjusted for fuel, site altitude and site inlet air temperature.
100% rating at maximum inlet air temperature is the maximum engine capability for the specified fuel at site altitude and maximum site inlet air temperature.
Max. rating is the maximum capability for the specified fuel at site altitude and reduced inlet air temperature.
Lowest load point is the lowest continuous duty operating load allowed. No overload permitted at rating shown.

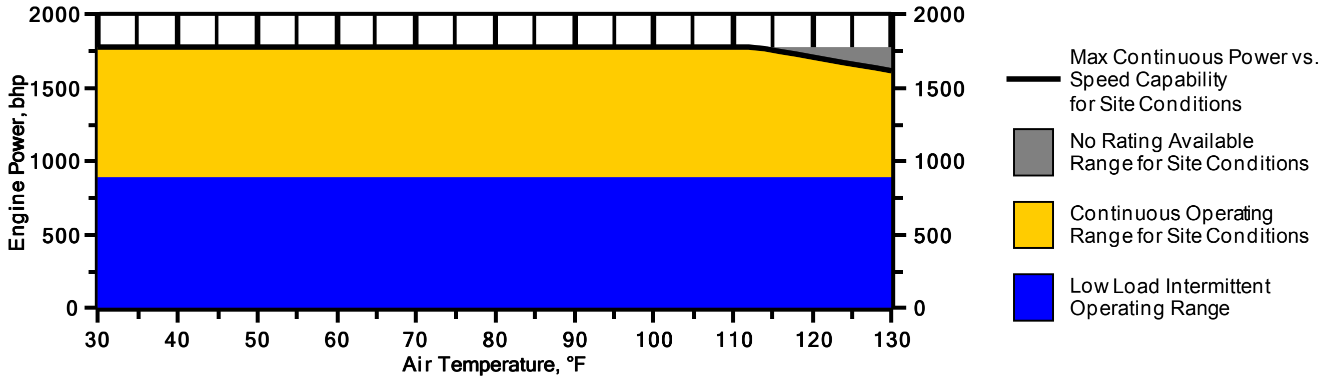
For notes information consult page three.

PREPARED BY: Jeff Weiler, Energy Transfer
Data generated by Gas Engine Rating Pro Version 3.04.00
Ref. Data Set DM8605-02-001, Printed 18Mar2011

GAS ENGINE SITE SPECIFIC TECHNICAL DATA
Jackson Co.

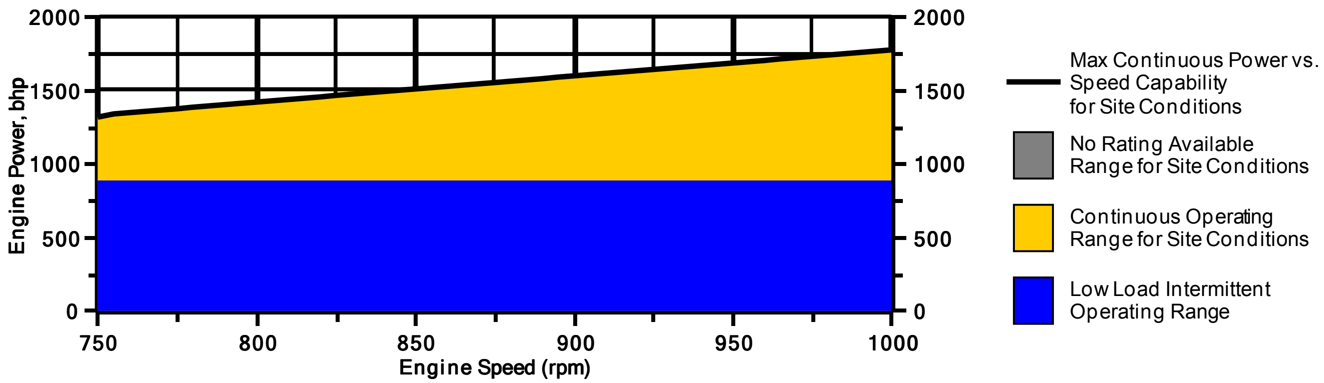
Engine Power vs. Inlet Air Temperature

Data represents temperature sweep at 300 ft and 1000 rpm



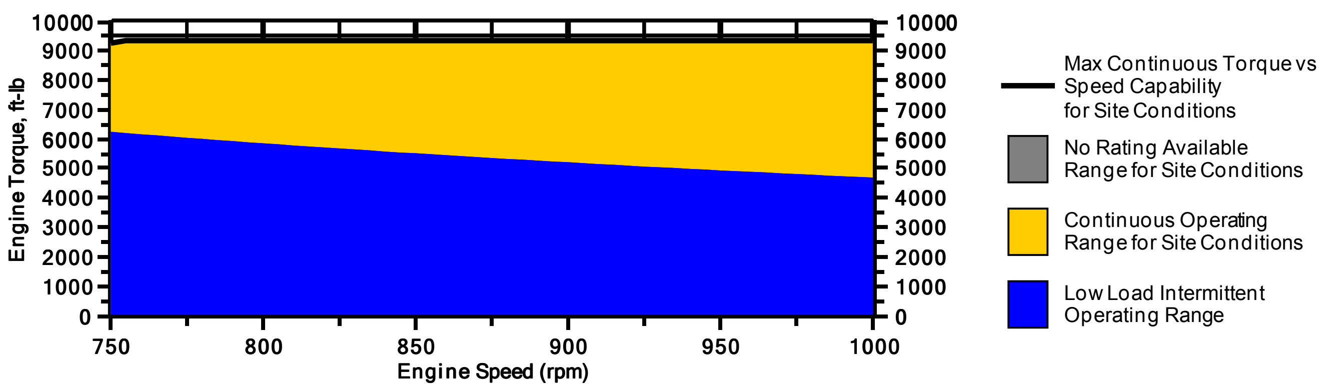
Engine Power vs. Engine Speed

Data represents speed sweep at 300 ft and 105 ºF



Engine Torque vs. Engine Speed

Data represents speed sweep at 300 ft and 105 ºF



Note: At site conditions of 300 ft and 105°F inlet air temp., constant torque can be maintained down to 755 rpm. The minimum speed for loading at these conditions is 750 rpm.

PREPARED BY: Jeff Weiler, Energy Transfer
Data generated by Gas Engine Rating Pro Version 3.04.00
Ref. Data Set DM8605-02-001, Printed 18Mar2011

GAS ENGINE SITE SPECIFIC TECHNICAL DATA
Jackson Co.

NOTES

1. Engine rating is with two engine driven water pumps. Tolerance is ± 3% of full load.

2. Fuel consumption tolerance is ± 2.5% of full load data.

3. Air flow value is on a 'wet' basis. Flow is a nominal value with a tolerance of ± 5 %.

4. Inlet and Exhaust Restrictions must not exceed A&I limits based on full load flow rates from the standard technical data sheet.

5. Inlet manifold pressure is a nominal value with a tolerance of ± 5 %.

6. Exhaust stack temperature is a nominal value with a tolerance of (+)63°F, (-)54°F.

7. Exhaust flow value is on a "wet" basis. Flow is a nominal value with a tolerance of ± 6 %.

8. Emission levels are at engine exhaust flange prior to any after treatment. Values are based on engine operating at steady state conditions, adjusted to the specified NOx level at 100% load. Fuel methane number cannot vary more than ± 3. Values listed are higher than nominal levels to allow for instrumentation, measurement, and engine-to-engine variations. They indicate "Not to Exceed" values. THC, NMHC, and NMNEHC do not include aldehydes. An oxidation catalyst may be required to meet Federal, State or local CO or HC requirements.

9. VOCs - Volatile organic compounds as defined in US EPA 40 CFR 60, subpart JJJJ

10. Exhaust Oxygen level is the result of adjusting the engine to operate at the specified NOx level. Tolerance is ± 0.5.

11. Heat rejection values are nominal. Tolerances, based on treated water, are ± 10% for jacket water circuit, ± 50% for radiation, ± 20% for lube oil circuit, and ± 5% for aftercooler circuit.

12. Aftercooler heat rejection includes an aftercooler heat rejection factor for the site elevation and inlet air temperature specified. Aftercooler heat rejection values at part load are for reference only. Do not use part load data for heat exchanger sizing.

13. Heat exchanger sizing criteria are maximum circuit heat rejection for the site, with applied tolerances.

PREPARED BY: Jeff Weiler, Energy Transfer
Data generated by Gas Engine Rating Pro Version 3.04.00
Ref. Data Set DM8605-02-001, Printed 18Mar2011

Constituent	Abbrev	Mole %	Norm
Water Vapor	H_2O	0.0000	0.0000
Methane	CH_4	92.2700	92.2700
Ethane	C_2H_6	2.5000	2.5000
Propane	C_3H_8	0.5000	0.5000
Isobutane	iso-C_4H_{10}	0.0000	0.0000
Norbutane	nor-C_4H_{10}	0.2000	0.2000
Isopentane	iso-C_5H_{12}	0.0000	0.0000
Norpentane	nor-C_5H_{12}	0.1000	0.1000
Hexane	C_6H_{14}	0.0500	0.0500
Heptane	C_7H_{16}	0.0000	0.0000
Nitrogen	N_2	3.4800	3.4800
Carbon Dioxide	CO_2	0.9000	0.9000
Hydrogen Sulfide	H_2S	0.0000	0.0000
Carbon Monoxide	CO	0.0000	0.0000
Hydrogen	H_2	0.0000	0.0000
Oxygen	O_2	0.0000	0.0000
Helium	HE	0.0000	0.0000
Neopentane	neo-C_5H_{12}	0.0000	0.0000
Octane	C_8H_{18}	0.0000	0.0000
Nonane	C_9H_{20}	0.0000	0.0000
Ethylene	C_2H_4	0.0000	0.0000
Propylene	C_3H_6	0.0000	0.0000
TOTAL (Volume %)		100.0000	100.0000

Fuel Makeup:	Nat Gas
Unit of Measure:	English

Calculated Fuel Properties

Caterpillar Methane Number:	84.8
Lower Heating Value (Btu/scf):	905
Higher Heating Value (Btu/scf):	1004
WOBBE Index (Btu/scf):	1168
THC: Free Inert Ratio:	0
RPC (%) (To 905 Btu/scf Fuel):	100%
Compressibility Factor:	0.998
Stoich A/F Ratio (Vol/Vol):	9.45
Stoich A/F Ratio (Mass/Mass):	15.75
Specific Gravity (Relative to Air):	0.600
Specific Heat Constant (K):	1.313

CONDITIONS AND DEFINITIONS

Caterpillar Methane Number represents the knock resistance of a gaseous fuel. It should be used with the Caterpillar Fuel Usage Guide for the engine and rating to determine the rating for the fuel specified. A Fuel Usage Guide for each rating is included on page 2 of its standard technical data sheet.

RPC always applies to naturally aspirated (NA) engines, and turbocharged (TA or LE) engines only when they are derated for altitude and ambient site conditions.

Project specific technical data sheets generated by the Caterpillar Gas Engine Rating Pro program take the Caterpillar Methane Number and RPC into account when generating a site rating.

Fuel properties for Btu/scf calculations are at 60F and 14.696 psia.

Caterpillar shall have no liability in law or equity, for damages, consequently or otherwise, arising from use of program and related material or any part thereof.

FUEL LIQUIDS

Field gases, well head gases, and associated gases typically contain liquid water and heavy hydrocarbons entrained in the gas. To prevent detonation and severe damage to the engine, hydrocarbon liquids must not be allowed to enter the engine fuel system. To remove liquids, a liquid separator and coalescing filter are recommended, with an automatic drain and collection tank to prevent contamination of the ground in accordance with local codes and standards.

To avoid water condensation in the engine or fuel lines, limit the relative humidity of water in the fuel to 80% at the minimum fuel operating temperature.

MIRATECH CORPORATION

To:	Jeff Weiler Energy Transfer Company X X Houston, TX X	**Phone:** **Mobile:** **Fax:** **Email:**	210-403-7323 210-289-4550 210-403-7523 Jeff.Weiler@energytransfer.com
CC:	David Zenthoefer/MIRATECH Corporation		
From:	Debora Calderón MIRATECH Corporation 420 S 145th E Ave Mail Drop A Tulsa, OK 74108	**Phone:** **Fax:** **Email:**	918-933-6271 918-933-6268 dcalderon@miratechcorp.com

Project Reference:	3606
Proposal Number:	DZ-11-1874 Rev(1)
Date:	**7/27/2011**
Firm Quote For:	**30 days from Proposal Date**

Dear Jeff:

MIRATECH Corporation welcomes the opportunity to provide you with a proposal for an NSCR system. We are confident that your organization will benefit from selecting us for this project for the following reasons:

- **Experience.**
  - MIRATECH is the leader in providing NSCR, SCR & DPF systems; having more than 17,000 successfully operating units installed in North America, South America, Europe and Asia.
- **World-Class Technology.**
  - Consistently set the standards for Best Available Control Technology (BACT)
  - Simple, user-friendly control and communication technology; connects to any building's communication systems
- **U.S.-based Field Services & Support.**
  - Fast-response field service & technical support
  - Replacement components in stock in Tulsa, Oklahoma
  - In-house engineering & product support

The system offered for this project is in accordance with the data received or estimated from your company. The system is designed to provide emission reduction for carbon monoxide (CO), hydrocarbons (NMNEHC), and formaldehyde (CH2O) as listed on the System Specifications and Performance Warranty Data page. MIRATECH warrants the quoted performance based on the engine emission and operating data you have provided us and that is contained in this proposal. Please note that some engine assumptions were used and converter size may change based on actual engine data.

Once again, thank you for the opportunity to provide this proposal. If you have any questions, please do not hesitate to contact me. I will call you next week to confirm your receipt and satisfaction with this proposal.

Best Regards,

Debora Calderón
Inside Sales
MIRATECH Corporation

Engineer Sized By: Brian Hoppe/MIRATECH Corporation

Quotation Summary

The prices are as follows:

NSCR System

Components	QTY/Engine	Total QTY	Price/Engine	Total Price
NSCR Housing & Catalyst				
NSCR Housing - *ZHS-42x41-18/20-HSG*	1	1	$7,161.00	$7,161.00
Oxidation Catalyst - *ZXS-RE-FULL354XH*	3	3	$12,747.00	$12,747.00
Blind Catalyst - *ZXS-RE-FULLBLIND*	1	1	$399.00	$399.00
Nut, Bolt, and Gasket Set - *NBG-ZXS4*	1	1		
			Price/Engine	**Total Price**
System Total			**$20,307.00**	**$20,307.00**

Terms and Conditions

This offer is in strict adherence to the attached *MIRATECH Holdings Terms and Conditions Rev 9 dated May 2011*.

Shipment

All equipment is Ex Works Tulsa, OK

Delivery

The following lead times specify the time from receipt of order by MIRATECH to product ready to ship. Lead times shown are for quantities of 1 or 2 unless otherwise specified. **For quantities in excess of 2, please obtain a commitment from MIRATECH**.

Contact MIRATECH for Lead Time (ZHS-42x41-18/20-XH3B1)

Payment Terms

Invoice on shipment, payment net 30 days (subject to account status).

Scope of Supply

MIRATECH Corporation Scope of Supply

	Model Number	Quantity per Engine
NSCR Housing & Catalyst	**ZHS-42x41-18/20-XH3B1**	
NSCR Housing	ZHS-42x41-18/20-HSG	1
Oxidation Catalyst	ZXS-RE-FULL354XH	3
Blind Catalyst	ZXS-RE-FULLBLIND	1
Nut, Bolt, and Gasket Set	NBG-ZXS4	1

Customer Scope of Supply

Description
Support Structure
Attachment to Support Structure (Bolts, Nuts, Levels, etc.)
Expansion Joints
Exhaust Piping
Inlet Pipe Bolts, Nuts, & Gasket
Outlet Pipe Bolts, Nuts, & Gasket

Application Data

Project Information

Site Location:	USA
Project Name:	3606
Application:	Gas Compression
Number of Engines:	1
Operating Hours per Year:	8760

Engine Specifications

Engine Manufacturer:	Caterpillar
Model Number:	G3606
Rated Speed:	1,000 RPM
Type of Fuel:	Natural Gas
Type of Lube Oil:	0.6 wt% sulfated ash or less
Lube Oil Consumption:	< 0.00027 gal/bhp-hr

Engine Cycle Data

Load	Speed	Power	Exhaust Flow	Exhaust Temp.	Fuel Cons.	NO_x	CO	NMHC	NMNEHC	CH_2O	PM_{10}	O_2	H_2O
%		*bhp*	*acfm (cfm)*	*F*	*BTU/bhp-hr*	*g/bhp-hr*	*g/bhp-hr*	*g/bhp-hr*	*g/bhp-hr*	*g/bhp-hr*	*g/bhp-hr*	*%*	*%*
100	Rated	1775	12146	847	7555	0.5	2.75	0.95	0.63	0.26		12.8	17

Raw Engine Emission Data

	g/bhp-hr	lb/MW-hr	ppmvd	ppmvd @ 15% O_2	lb/hr	g/kW-hr	tons/yr
NO_x	0.50	1.48	67	49	1.96	0.67	8.57
CO	2.75	8.13	606	441	10.76	3.69	47.13
NMNEHC	0.63	1.86	242	176	2.47	0.84	10.80
CH_2O	0.26	0.77	53	39	1.02	0.35	4.46

% O_2	12.8
H_2O Assumption	17.0

System Specifications and Performance Warranty Data

NSCR System Specifications (ZHS-42x41-18/20-XH3B1)

Design Exhaust Flow Rate:	12,146 acfm (cfm)
Design Exhaust Temperature[1]:	847°F
Housing Model Number:	ZHS-42x41-18/20-HSG
Element Model Number:	ZXS-RE-FULL354XH, ZXS-RE-FULLBLIND
Number of Catalyst Elements:	3
Number of Spare Catalyst Tracks:	1
System Pressure Loss:	5.0 inches of WC (Fresh)
Sound Attenuation:	27-35 dBA insertion loss
Exhaust Temperature Limits:	550 – 1250°F (catalyst inlet); 1350°F (catalyst outlet)

Post System Emission Data

	g/bhp-hr	lb/MW-hr	ppmvd	ppmvd @ 15% O_2	lb/hr	g/kW-hr	tons/yr
CO	0.14	0.41	30	22	0.54	0.18	2.36
NMNEHC	0.25	0.75	97	71	0.99	0.34	4.32
CH_2O	0.02	0.05	4	3	0.07	0.02	0.31

Calculated Percent Reductions

	% Reduction
CO	95.0
NMNEHC	60.0
CH2O	93.0

Equipment Details

NSCR Housing & Catalyst Details (ZHS-42x41-18/20-XH3B1)

NSCR Housing Details	ZHS-42x41-18-20 SD
• Model Number:	ZHS-42x41-18/20-HSG
• Quantity²:	1
• Material:	Carbon Steel
• Paint:	Standard High Temperature Black Paint
• Diameter:	42 inches
• Inlet Pipe Size & Connection:	18 inch FF Flange, 150# ANSI standard bolt pattern
• Outlet Pipe Size & Connection:	20 inch FF Flange, 150# ANSI standard bolt pattern
• Overall Length:	180 inches
• Weight Without Catalyst:	1,998 lbs
• Weight Including Catalyst:	2,133 lbs
• Instrumentation Ports:	2 inlet/2 outlet (1/2" NPT)
Oxidation Catalyst Details	
• Model Number:	ZXS-RE-FULL354XH
• Quantity²:	3
Blind Catalyst Details	
• Model Number:	ZXS-RE-FULLBLIND
• Quantity²:	1
Nut, Bolt, and Gasket Set Details	
• Model Number:	NBG-ZXS4
• Quantity²:	1

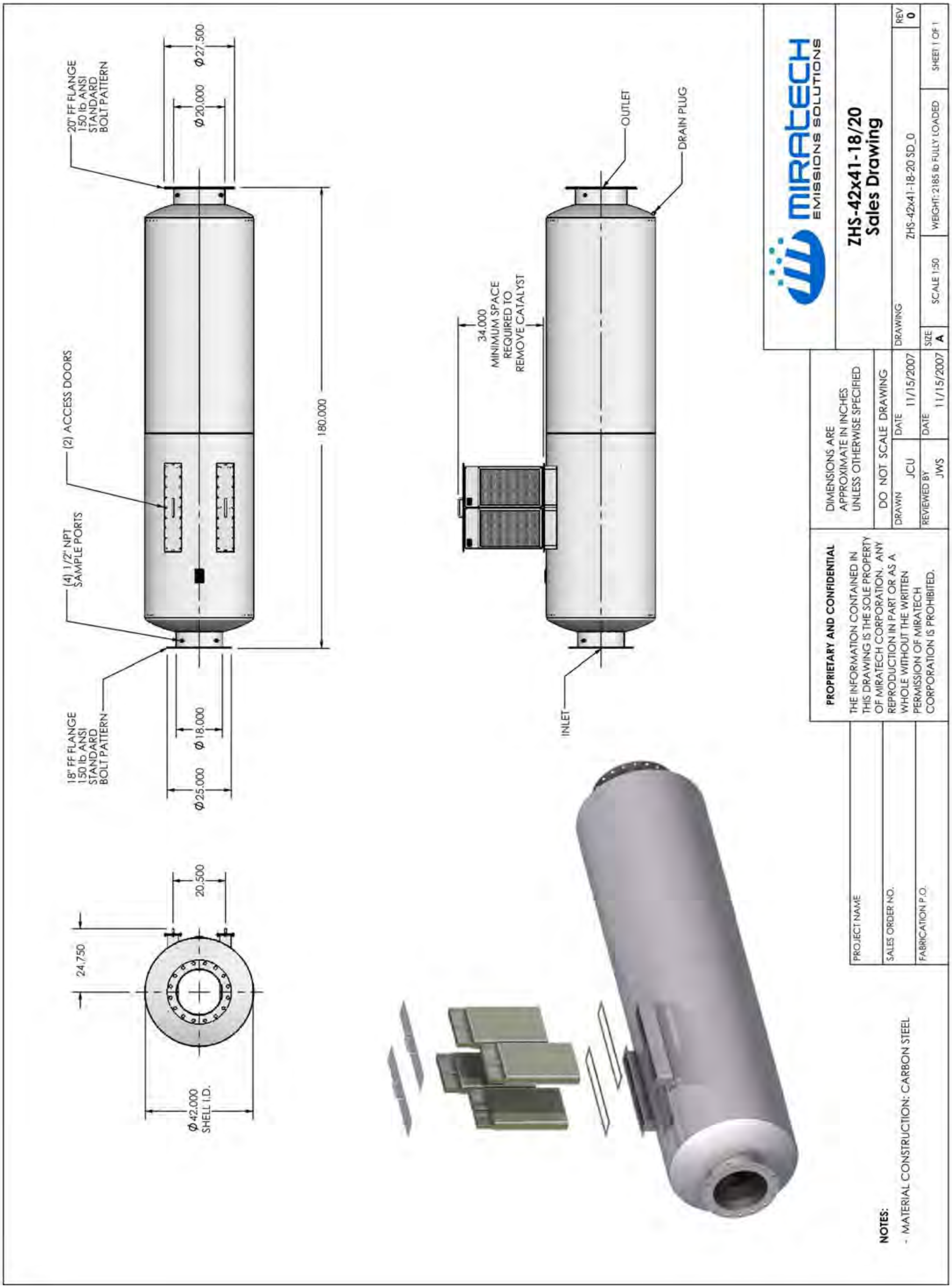
Special Notes/Conditions

1 Carbon steel housings are suitable for use in all applications where the housing will not be insulated. Carbon steel housings may only be insulated in applications where the exhaust temperature does not exceed 900°F. If your application requires insulation with an engine exhaust temperature exceeding 900°F, a stainless steel housing is required. Customer installed insulation on carbon steel housings in applications where exhaust temperature exceeds 900°F voids any MIRATECH product warranty.

2 Quantities are per engine.

- A packed silencer installed upstream of the MIRATECH catalyst system will void MIRATECH's limited warranty.
- Final catalyst housings are dependent on engine output and required emission reductions. Changes may be made to optimize the system design at the time of order.
- Any drawings included with this proposal are preliminary in nature and could change depending on final product selection.
- Any sound attenuation listed in this proposal is based on housing with catalyst elements installed.

NSCR Housing Drawing



Domestic Onshore Technical Service Rate Schedule

The Day Rate is charged for supervision of work performed over and above the scope of an installation or services contract. MIRATECH standard Terms and Conditions of Sale apply to all activities.

Technical Services Supervisor Day Rate	**$1,200.00**

Additional Information

- **The standard Day Rate is for an 8-hour, onshore, non-holiday, weekday and is the minimum charge.**
- **Charges for greater than 8 hours but less than 12 hours in a single calendar day** - The number of hours of supervision in a single calendar day divided by 8 and multiplied by the standard Day Rate times any applicable multipliers for Weekends and Holidays (see below). (example - 10 hours of supervision in a single day - 10/8 x $1,200 = $1,500)
- **Charges for greater than 12 hours per day** - Actual time worked over 12 hours per day will be charged at a rate of $225.00 per hours or 1.5 times the calculated hourly rate, which ever is greatest.
- **Travel Time** - actual hours traveled each way divided by 8 and multiplied by the standard Day Rate. No multipliers are applicable. (example - 5 hours traveled to site - 5/8 x $1,200 = $750)
- **Saturday** - 1.5 times the standard Day Rate
- **Sundays** - 2 times the standard Day Rate
- **All National Holidays** - 3 times the standard Day Rate

Expense Invoicing Rates

MIRATECH Actual Cost plus 5% - Lodging, phone, meals, parking, air travel, rental cars and incidental costs.

Company Vehicle Mileage at:	**$ 1.00 per mile**
Portable Exhaust Gas Analyzer	**$ 400.00/calendar day**
Special Tools and Equipment rental	**cost plus 15%**

420 S. 145th E. Avenue, Mail Drop A, Tulsa, OK 74108-1305
Phone Number (800) 640-3141 FAX Number (918) 622-3928
www.MIRATECHcorp.com

GENERAL TERMS AND CONDITIONS OF SALE

1. **Integration** The General Terms and Conditions of Sale contained herein shall be deemed a material part of any sale or proposed sale by MIRATECH Holdings, LLC ("Seller") to ________________ ("Purchaser") and, unless and only to the extent specifically excluded therein, shall be a material part of any subsequent letter of authorization, contract, purchase order, sale or other agreement between Seller and Purchaser, with respect to all products, equipment, services and/or parts relating thereto (hereinafter referred to as the "Product").

2. **Compliance** To Seller's knowledge, Seller has complied with all applicable laws and regulations including, but not limited to, the Fair Labor Standards Act, the Civil Rights Act of 1964, the Equal Employment Opportunity Act of 1972, as respectively amended, Executive Orders 11246, 11375 and 11141 (Title 41, Chapter 60, Code of Federal Regulations), the Vietnam Era Veterans Readjustment Act of 1974, and all amendments thereto and regulations, rules and orders there under, as amended or superseded and all of the foregoing are made a part hereof by reference and incorporated herein as though fully set forth herein. Purchaser understands and agrees that the foregoing sentence is for Purchaser's information stating that which Seller strives to achieve and is not made as a covenant, warranty or representation and is not meant to create or permit, nor shall it be construed as creating or permitting any enforceable rights hereunder for Purchaser or any other person or entity. All standards promulgated with respect to noise or air control are specifically excluded hereunder.

3. **Title, Risk of Loss, Security Interest** Title and risk of loss or damage to the Product shall pass to Purchaser under tender of delivery Ex-Works manufacturing facility unless expressly stipulated otherwise, regardless of when partial or final payment is to be made by Purchaser. Notwithstanding the foregoing, a purchase money security interest in the Product or any replacement thereof shall remain in Seller, regardless of mode of attachment to realty or other property, until full payment has been made therefore and collected by Seller.

4. **Inspection, Rejection, Remedy** Purchaser shall have the right to reasonable inspection of the Product after delivery to destination, which inspection shall be completed within ten (10) days of the date of delivery to such destination. Any rejection by Purchaser as to part or all of the Product shall be in writing, specifically stating the non-conformities thereof. In such event, Seller shall have a reasonable period of time to determine the validity of and, if necessary, to correct the non-conformities forming the basis of the Purchaser's rejection or, at Seller's option and if appropriate, to replace part or all of the Product. Purchaser's failure to make rejection as herein stated, or to allow Seller to cure Purchaser's objections, shall be deemed to conclusively establish acceptance by Purchaser of the Product.

5. **Time, Force Majeure** Seller may, from time to time, quote delivery dates to Purchaser. Such dates shall be interpreted as estimated and in no event shall such dates be construed as falling within the meaning of "time is of the essence." Seller shall not be liable for loss, damage, detention, or delay due to war, riots, civil insurrection or acts of the common enemy, fire, flood, severe weather conditions at Seller's premises or outside fabrication sites, strikes or other labor difficulties, acts of civil or military authority including governmental law, orders, priorities or regulations, acts of Purchaser, embargo, car shortage, wrecks or delay in transportation, inability to obtain necessary labor, materials or manufacturing facilities from usual sources, faulty forgings or castings, or other causes beyond the reasonable control of Seller. In the event of delay in performance due to any such cause, the date of delivery or time for completion shall be adjusted to reflect the actual length of time necessary to properly reflect the delay without change to the purchase price. In the event of such delay or default in delivery, Seller shall complete work in progress and/or make delivery as soon as reasonably practicable. Upon completion and delivery of the Product to Purchaser, after such delay in delivery, the obligation of Purchaser for payment shall be completely reinstated.

6. **Taxes** Prices quoted by Seller do not include any federal, state or local property, license, privilege, sales, use, excise, gross receipts or other like taxes which may now or hereafter be applicable to, measured by, or imposed upon this transaction, the Product, its sale, its value, its use or any services performed in connection therewith. Such taxes shall be paid by Purchaser or, if paid by Seller, shall be itemized separately to Purchaser, who shall make prompt payment therefore to Seller.

7.1 **Limited Warranty** Subject to the exclusions contained herein, Seller warrants that the Next and Vortex Substrates utilizing catalyst formulations other than "EU" and "XU" formulation designations shall be free of defects in material and workmanship for a period of twenty-four (24) months from the date the Product is complete and ready for shipment; Next and Vortex Substrates utilizing "EU" or "XU" catalyst formulation designations shall be free of defects in material and workmanship for a period of thirty-six (36) months from the date the Product is placed in operation, thirty-eight (38) months from the date the Product is complete and ready for shipment, or one-thousand-eight-hundred (1800) hours of operation, whichever shall first occur; and all other Products shall be free of defects in material and workmanship for a period of twelve (12) months from the date the Product is placed in operation or eighteen (18) months from the date the Product is complete and ready for shipment, whichever shall first occur, and provided Purchaser shall, within such period, notify Seller in writing of such defect(s) and fully cooperate with Seller in pursuing the remedying thereof. Should any failure to conform to this warranty be reported to Seller within said period, Seller shall, upon Purchaser promptly notifying Seller in writing thereof, correct such nonconformity by suitable repair to the Product or, at Seller's option, furnish replacement parts F.O.B. Seller's point of shipment, provided Purchaser has restored the Product to the "as shipped" condition prior to installation and has installed, maintained and operated the Product in accordance with standard industry practices and has complied with the specific recommendations of Seller respecting the Product. Accessories or other parts of the Product furnished by Seller, but manufactured by others, shall carry whatever warranty, if any, the manufacturers thereof have given to Seller and which can be passed on to Purchaser. Purchaser agrees to look solely to such other manufacturers or suppliers of such accessories or parts for any warranty, repair or product liability claims arising out of the performance, condition or use of such accessories or parts. Seller agrees to cooperate in furnishing assignments of its rights thereto to Purchaser from such manufacturers and suppliers. Seller shall not be liable for any repairs, replacements or adjustments to the Product or any costs of labor performed by Purchaser without Seller's prior written approval. Seller's warranty shall expire in the event the Product is misused, neglected or operated other than for its intended purpose. Except as specifically stated herein, Seller makes no performance warranty of any kind respecting the Product. The effects of corrosion, erosion and normal wear and tear are specifically excluded from Seller's warranty.

Seller's warranty shall expire in the event: an A-36 carbon steel housing provided by Seller is insulated and operated with an inlet operating temperature to the housing greater than 900 deg F; or a component supplied by others that is upstream of the Seller's provided scope damages the Seller provided scope.

Correction by Seller of non-conformities, whether patent or latent, in the manner and for the period of time provided above, shall constitute fulfillment of all liabilities of Seller for such non-conformities, whether based on contract, warranty, negligence, indemnity, strict liability or otherwise with respect to or arising out the Product. Seller shall in no event be liable for consequential damages.

7.2 **Limited Warranty, Conditions** Throughout the Warranty Period, Seller warrants that the Product will achieve the emissions levels set forth in the Proposal referenced in and attached to the Contract between Seller and Purchaser, subject to the conditions that

a. the Product is operated and maintained at all times in accordance with MIRATECH's written instructions;
b. the Purchaser's equipment is operated and maintained at all times in accordance with all manufacturer's instructions and guidelines;
c. the Purchaser's equipment, during operation, shall never exceed the raw emission rate, the flow rate or temperature levels set forth in the Proposal;
d. the Purchaser's equipment shall be operated within the temperature limits stated in the Proposal after startup;
e. the Purchaser will operate the equipment so the engine emissions & temperature are as stated in the proposal and:
    1. the NO_x, CO, VOC/NMNEHC, O_2, and $PM_{2.5}$ will not fluctuate more than 2% from the Proposal value and
    2. the Exhaust flow rate will not fluctuate more than 2% from the Proposal value and
    3. the Exhaust temperature into the catalyst will not fluctuate more than 10°F from the Proposal value.

Emissions levels, temperature and flow rates from Purchaser's equipment and the Product discharge point shall be tested at the Purchaser's expense, in accordance with a mutually agreed test procedure and protocol consistent with accepted industry practices.

If the above conditions are met and the Product fails to achieve the output performance stated in the Proposal within the Warranty Period, Seller will replace or modify and adjust its Product as needed to meet such output performance standards. Purchaser is required to notify the Seller in writing of the specific defect and provide Seller with complete documentation of the defect and satisfaction of all conditions, a - e, of this article. If Seller is unable to achieve the output performance standards under the Contract conditions within a mutually agreed to time period, Purchaser may rescind the sale, and Seller shall return the purchase price.

7.3 **Warranty Disclaimer** **SELLER MAKES NO OTHER WARRANTY OR REPRESENTATION OF ANY KIND WHATSOEVER, EXPRESSED OR IMPLIED, EXCEPT THAT OF GOOD TITLE TO THE PRODUCT, AND ALL IMPLIED WARRANTIES, INCLUDING ANY WARRANTY OF MERCHANTABILITY AND/OR FITNESS FOR A PARTICULAR PURPOSE, ARE HEREBY DISCLAIMED.**

8. **Remedies Exclusive** The remedies of Purchaser set forth herein are exclusive. The total liability of Seller with respect to the performance and other matters related to the manufacture, sale, delivery, installation, repair or technical direction thereof, whether based on contract, warranty, negligence, indemnity, strict liability or otherwise, shall in no event exceed the purchase price of the particular Unit of Product upon which such liability is based, and not the aggregate of all Products covered by any agreement or document between Seller and Purchaser. Seller shall, in no event, be liable to Purchaser, any successors in interest or any beneficiary or assignee of Purchaser, for any consequential, incidental, indirect, special or punitive damages or any defect in, or failure or malfunction of, the Product, whether based upon lost goodwill, lost profits or revenue, interest, work stoppage, impairment of other goods, loss by reason of shutdown or non-operation, increased expenses of operation of Product, loss of use of power system, costs of purchase of replacement power or claims of Purchaser or customers of Purchaser for service interruption, whether or not such loss or damage is based on contract, warranty, negligence, indemnity, strict liability or otherwise. Purchaser warrants that the Product is purchased for, and will be used for, business purposes only by qualified and properly trained personnel.

9. **Set-off** Purchaser shall not have the right to retain, back charge, or set off against any amounts which may be or become payable by it to Seller or otherwise, for amounts which Seller may allegedly or in fact owe Purchaser whether arising hereunder or otherwise.

10. **Governing Law - Venue** The rights and obligations of Purchaser and Seller shall be construed in accordance with and governed by the laws of the State of Oklahoma, notwithstanding any conflict of law provisions which would have the effect of making the law of another state applicable. Seller and Purchaser agree that venue respecting any and all disputes between Purchaser and Seller with regard to the Product shall be Tulsa County, Oklahoma.

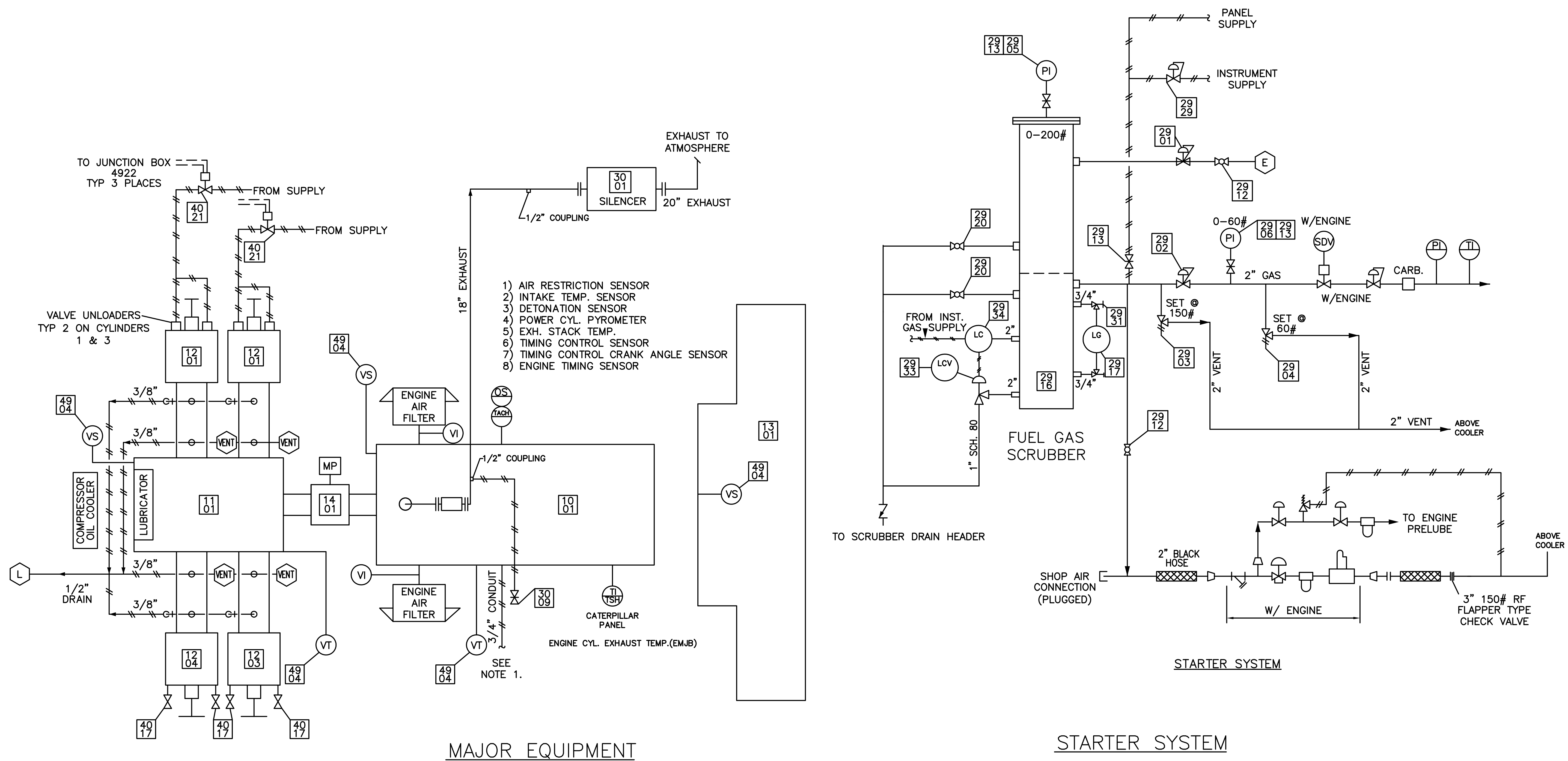
11. **No Waiver** No waiver by Seller of any breach of any obligation of Purchaser set forth in the General Terms and Conditions herein shall be construed as a waiver of any succeeding breach of the same or of any covenant or condition, and in no event shall this provision itself be waived.

12. **Payment** Payment terms shall be as stated in the letter of authorization, purchase order or other agreement between Seller and Purchaser. Terms of payment are net ten (10) days from date of invoice, unless otherwise agreed in writing.

13.1 **Cancellation of Contract before Delivery** For standard products, a cancellation charge equal to, in the sole discretion of the Seller, not more than 50% of the original purchase price may be made for any cancellation of the Contract by Purchaser prior to Seller's delivery of the Product to Purchaser. For custom products, a cancellation charge equal to, in the sole discretion of the Seller, not more than 100% of the original purchase price may be made for any cancellation of the Contract by Purchaser prior to Seller's delivery of the Product to Purchaser. The parties agree that such cancellation charges represent Seller's liquidated damages arising out of cancellation of the Contract in lieu of actual damages, it being understood and agreed between the parties that Seller's actual damages would be impractical or extremely difficult, time consuming and expensive to ascertain. Seller's failure to impose a cancellation charge with respect to one or more cancellations by Purchaser and/or other customers shall not be deemed in any case a waiver of its right under the Contract to impose such a charge in connection with any other cancellation by Purchaser, and Purchaser may not rely on any representation of any person to the contrary.

13.2 **Returns** Subject to Purchaser's payment in advance of a restocking fee and any associated shipping and handling costs, Seller will accept return of a Product within 90 days following delivery of the Product to Purchaser if the Product is returned to Seller complete and uninstalled in new condition. The amount of such restocking fee will be determined in accordance with Seller's then current Return Material Authorization policy. Any return of a Product more than 90 days following delivery, including the terms thereof, shall be within the sole and absolute discretion of the Seller.

14. **Conflicting Provisions** In case of any conflict, the General Terms and Conditions contained herein shall supersede any and all specifications and/or other terms and conditions previously supplied by Purchaser in connection with or upon a letter of authorization, purchase order or any other agreement, as well as any custom, prior conduct or course of dealing. No agreement, oral representation or other understanding any way modifying or amending the General Terms and Conditions, or having the effect of enlarging the obligations of Seller hereunder, shall be binding upon the Seller unless such modification is clear, certain and in writing in the form of an amended letter of authorization, purchase order or other agreement duly executed by Purchaser and an authorized representative of Seller.



MARK	QUAN.	SIZE	RATING	TYPE	SERVICE
P	FOUR	1"	3000#	FNPT	EJW MAKE UP
O	FOUR	2"	3000#	FNPT	SKID DRAIN BOXES
N	ONE	1"	3000#	FNPT	LUBE OIL MAKEUP
L	ONE	1/2"	3000#	FNPT	PACKING VENT AND DIST. PIECE DRAINS
J	ONE	1"	3000#	FNPT	EJW LOW POINT DRAIN / TAW DRAIN
H	ONE	2"	3000#	FNPT	ENGINE AND COMPRESSOR OIL DRAIN
F	ONE	1"	3000#	FNPT	SCRUBBER DRAIN HEADER
E	ONE	2"	3000#	FNPT	FUEL GAS INLET
B	ONE	10"	900#	RFWN	UNIT DISCHARGE
A	ONE	12"	600#	RFWN	UNIT INLET

CUSTOMER CONNECTION SCHEDULE

MAJOR EQUIPMENT

COMPRESSOR – ARIEL JGD/4
(2) 9 3/4" "DM" CYL. (BORE 9 1/4")
(2) 9 3/4" "DM" CYL. (BORE 9 1/4")

ENGINE – CATERPILLER 3606
COUPLING – FSH 750
COOLER – AIR-X-CHANGERS 156-EH
PANEL – BY CUSTOMER

DO NOT SCALE DRAWING

REV	DESCRIPTION	DRAWN	CHK'D	APPR	DATE
0	ISSUED FOR CONSTRUCTION	GB	T.A.	T.A.	11/06/07

Standard Equipment Company
Energy Products and Services L.P.

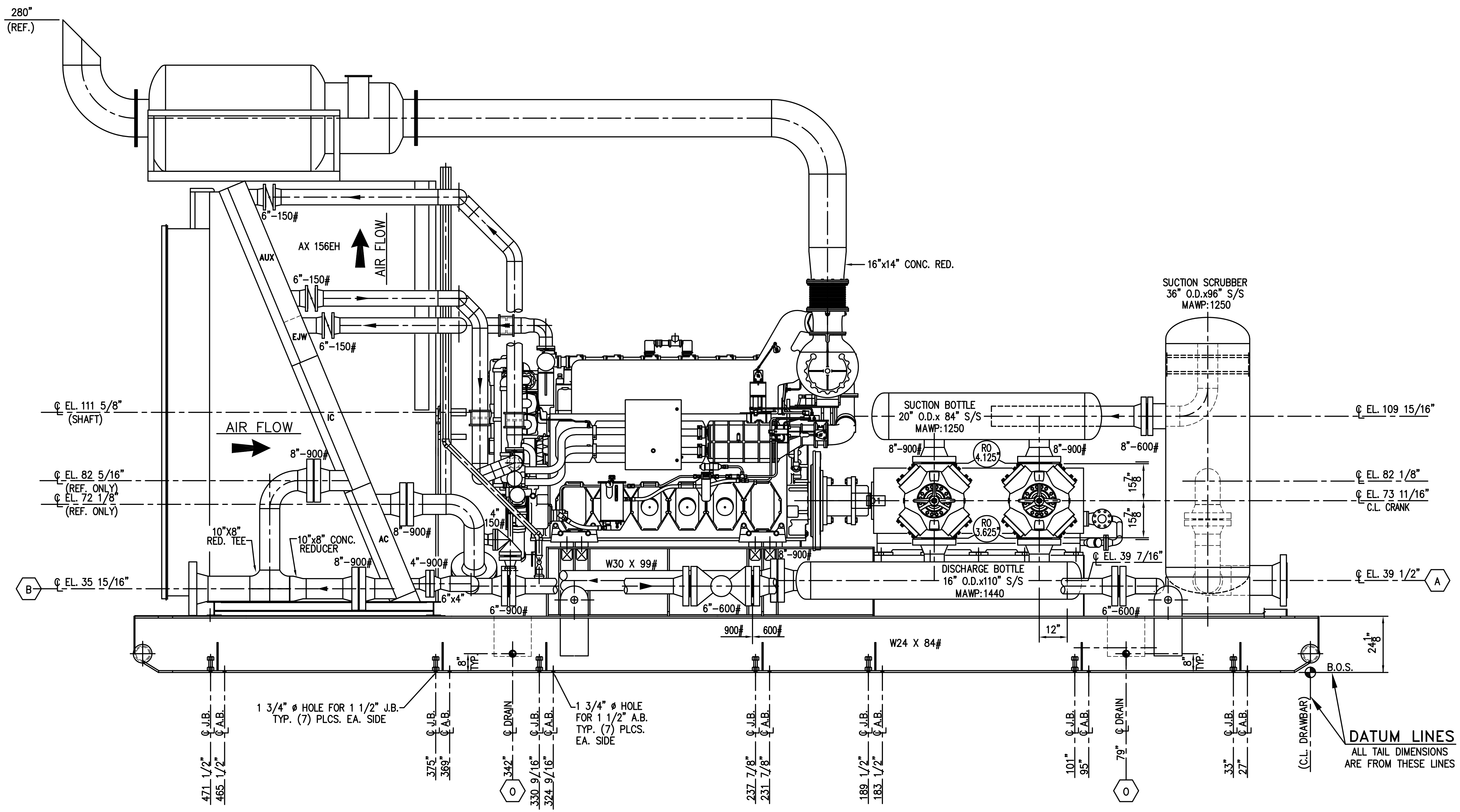
JOB No.: 2318 | ITEM TAG No.: | DRAWN BY: JTA | CHECKED BY: | DATE: 10/20/06 | SCALE: NONE | D

JOB SCOPE PART NUMBER 7003606500

COMPRESSOR UTILITY
P & ID

ENERGY TRANSFER

DWG. No. 2318-100-02 | SHEET 2 OF 3 | REV 0



SOUTH ELEVATION

MAJOR EQUIPMENT

COMPRESSOR – ARIEL JGD/4
(2) 9 3/4" "DM" CYL. (BORE 9 1/4")
(2) 9 3/4" "DM" CYL. (BORE 9 1/4")

ENGINE – CATERPILLER 3606
COUPLING – FSH 750
COOLER – AIR-X-CHANGERS 156-EH
PANEL – BY CUSTOMER

DO NOT SCALE DRAWING

REV	DESCRIPTION	DRAWN	CHK'D	APPR	DATE
0	ISSUED FOR CONSTRUCTION	GB	TA	TA	11/06/07

Standard Equipment Company
Energy Products and Services L.P.

JOB No.: 2318
ITEM TAG No.:
DRAWN BY: JTA
CHECKED BY: TA
DATE: 10/20/06
SCALE: 1/2"=1'-0"
D

JOB SCOPE PART NUMBER 7003606500

COMPRESSOR GENERAL ARRANGEMENT
SOUTH ELEVATION VIEW
CAT 3606 / ARIEL JGD-4
ENERGY TRANSFER COMPANY
S.E.C. UNIT 2318

DWG. No. 2318-200-02
SHEET 2 OF 4
REV 0

G3616

GAS COMPRESSION APPLICATION

GAS ENGINE SITE SPECIFIC TECHNICAL DATA
Run 1

CATERPILLAR®

ENGINE SPEED (rpm):	1000	FUEL SYSTEM:	GAV
COMPRESSION RATIO:	9:1		WITH AIR FUEL RATIO CONTROL
AFTERCOOLER WATER INLET (°F):	130	**SITE CONDITIONS:**	
JACKET WATER OUTLET (°F):	190	FUEL:	Jackson County Plant Ethane Rejection
ASPIRATION:	TA	FUEL PRESSURE RANGE(psig):	42.8-47.0
COOLING SYSTEM:	JW, OC+AC	FUEL METHANE NUMBER:	73.1
IGNITION SYSTEM:	CIS/ADEM3	FUEL LHV (Btu/scf):	994
EXHAUST MANIFOLD:	DRY	ALTITUDE(ft):	500
COMBUSTION:	Low Emission	MAXIMUM INLET AIR TEMPERATURE(°F):	77
NOx EMISSION LEVEL (g/bhp-hr NOx):	0.7	STANDARD RATED POWER:	4735 bhp@1000rpm

				MAXIMUM RATING	SITE RATING AT MAXIMUM INLET AIR TEMPERATURE		
RATING		NOTES	LOAD	100%	100%	75%	50%
ENGINE POWER	(WITHOUT FAN)	(1)	bhp	4735	4735	3551	2368
INLET AIR TEMPERATURE			°F	77	77	77	77
ENGINE DATA							
FUEL CONSUMPTION (LHV)		(2)	Btu/bhp-hr	6736	6736	7030	7694
FUEL CONSUMPTION (HHV)		(2)	Btu/bhp-hr	7453	7453	7778	8512
AIR FLOW (77°F, 14.7 psia)	(WET)	(3)(4)	scfm	11952	11952	9243	6347
AIR FLOW	(WET)	(3)(4)	lb/hr	52997	52997	40985	28145
INLET MANIFOLD PRESSURE		(5)	in Hg(abs)	72.0	72.0	55.4	39.6
EXHAUST TEMPERATURE - ENGINE OUTLET		(6)	°F	876	876	918	996
EXHAUST GAS FLOW (@engine outlet temp, 14.5 psia)	(WET)	(7)(4)	ft3/min	31646	31646	25253	18372
EXHAUST GAS MASS FLOW	(WET)	(7)(4)	lb/hr	54535	54535	42189	29023
EMISSIONS DATA - ENGINE OUT							
NOx (as NO2)		(8)(9)	g/bhp-hr	0.70	0.70	0.70	0.70
CO		(8)(9)	g/bhp-hr	2.50	2.50	2.50	2.50
THC (mol. wt. of 15.84)		(8)(9)	g/bhp-hr	6.01	6.01	6.26	6.49
NMHC (mol. wt. of 15.84)		(8)(9)	g/bhp-hr	1.41	1.41	1.46	1.52
NMNEHC (VOCs) (mol. wt. of 15.84)		(8)(9)(10)	g/bhp-hr	0.60	0.60	0.63	0.65
HCHO (Formaldehyde)		(8)(9)	g/bhp-hr	0.26	0.26	0.28	0.31
CO2		(8)(9)	g/bhp-hr	437	437	456	499
EXHAUST OXYGEN		(8)(11)	% DRY	11.7	11.7	11.5	11.1
HEAT REJECTION							
HEAT REJ. TO JACKET WATER (JW)		(12)	Btu/min	48213	48213	41728	34019
HEAT REJ. TO ATMOSPHERE		(12)	Btu/min	18606	18606	17476	16698
HEAT REJ. TO LUBE OIL (OC)		(12)	Btu/min	23922	23922	22885	22769
HEAT REJ. TO AFTERCOOLER (AC)		(12)(13)	Btu/min	32888	32888	14840	2949

COOLING SYSTEM SIZING CRITERIA	NOTES	LOAD	
TOTAL JACKET WATER CIRCUIT (JW)	(14)	Btu/min	58338
TOTAL AFTERCOOLER CIRCUIT (OC+AC)	(13)(14)	Btu/min	69562
A cooling system safety factor of 10% has been added to the cooling system sizing criteria.			

CONDITIONS AND DEFINITIONS

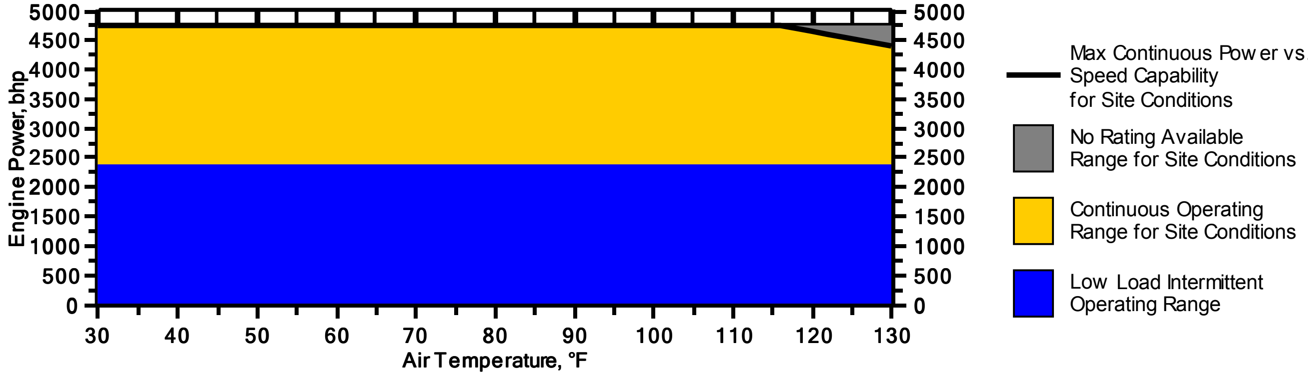
Engine rating obtained and presented in accordance with ISO 3046/1, adjusted for fuel, site altitude and site inlet air temperature. 100% rating at maximum inlet air temperature is the maximum engine capability for the specified fuel at site altitude and maximum site inlet air temperature. Max. rating is the maximum capability for the specified fuel at site altitude and reduced inlet air temperature. Lowest load point is the lowest continuous duty operating load allowed. No overload permitted at rating shown.

For notes information consult page three.

PREPARED BY:
Data generated by Gas Engine Rating Pro Version 3.05.00
Ref. Data Set DM5563-04-001, Printed 28Jul2011

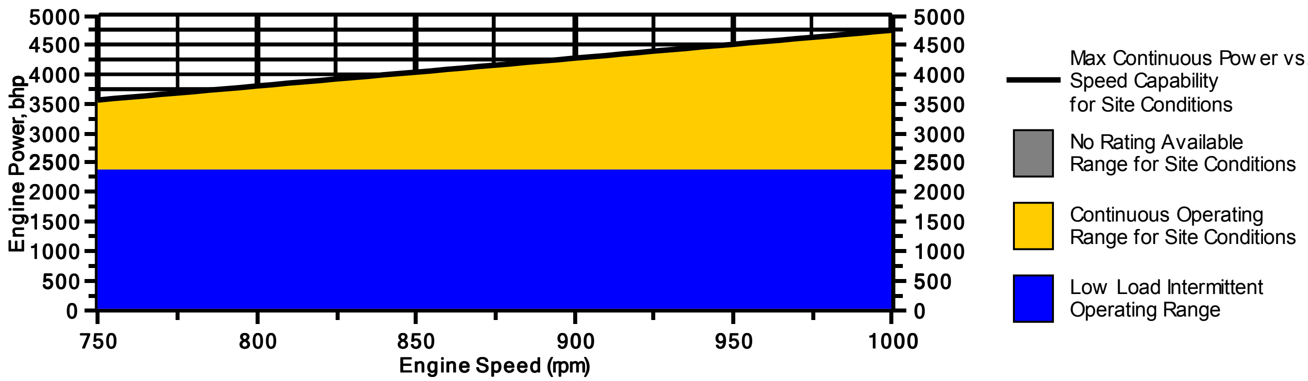
Engine Power vs. Inlet Air Temperature

Data represents temperature sweep at 500 ft and 1000 rpm



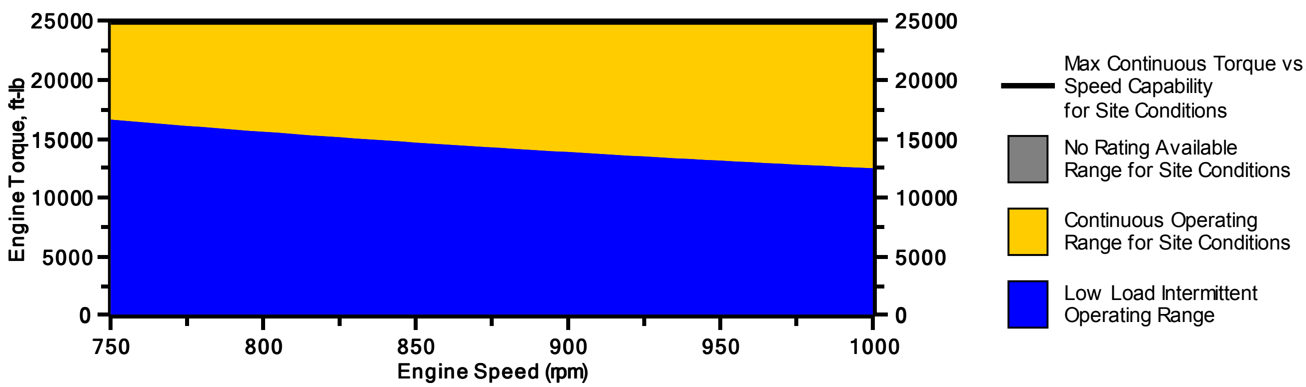
Engine Power vs. Engine Speed

Data represents speed sweep at 500 ft and 77 ºF



Engine Torque vs. Engine Speed

Data represents speed sweep at 500 ft and 77 ºF



Note: At site conditions of 500 ft and 77°F inlet air temp., constant torque can be maintained down to 750 rpm. The minimum speed for loading at these conditions is 750 rpm.

NOTES

1. Engine rating is with two engine driven water pumps. Tolerance is ± 3% of full load.

2. Fuel consumption tolerance is ± 2.5% of full load data.

3. Air flow value is on a 'wet' basis. Flow is a nominal value with a tolerance of ± 5 %.

4. Inlet and Exhaust Restrictions must not exceed A&I limits based on full load flow rates from the standard technical data sheet.

5. Inlet manifold pressure is a nominal value with a tolerance of ± 5 %.

6. Exhaust temperature is a nominal value with a tolerance of (+)63°F, (-)54°F.

7. Exhaust flow value is on a "wet" basis. Flow is a nominal value for total flow rate with a tolerance of ±6%. Exhaust gas vented through the wastegate flows only to the right exhaust outlet. The total flow through the wastegate may be as great as 15% of the total value for conditions under which the wastegate is open. For installations that use dual exhaust runs this difference must be taken into account when specifying any items to be connected to the exhaust outlets. The flow in the right exhaust outlet must be sized for at least 65% of the total flow to allow for the wastegate full open condition, while the left outlet must be sized for 50% of the total flow for the wastegate closed condition. Both runs must meet the allowable backpressure requirement as described in the Exhaust Systems A&I Guide.

8. Emissions data is at engine exhaust flange prior to any after treatment.

9. Emission values are based on engine operating at steady state conditions. Fuel methane number cannot vary more than ± 3. Values listed are higher than nominal levels to allow for instrumentation, measurement, and engine-to-engine variations. They indicate "Not to Exceed" values. THC, NMHC, and NMNEHC do not include aldehydes. An oxidation catalyst may be required to meet Federal, State or local CO or HC requirements.

10. VOCs - Volatile organic compounds as defined in US EPA 40 CFR 60, subpart JJJJ

11. Exhaust Oxygen level is the result of adjusting the engine to operate at the specified NOx level. Tolerance is ± 0.5.

12. Heat rejection values are nominal. Tolerances, based on treated water, are ± 10% for jacket water circuit, ± 50% for radiation, ± 20% for lube oil circuit, and ± 5% for aftercooler circuit.

13. Aftercooler heat rejection includes an aftercooler heat rejection factor for the site elevation and inlet air temperature specified. Aftercooler heat rejection values at part load are for reference only. Do not use part load data for heat exchanger sizing.

14. Cooling system sizing criteria are maximum circuit heat rejection for the site, with applied factory tolerances and an additional cooling system factor of 10%.

Constituent	Abbrev	Mole %	Norm
Water Vapor	H_2O	0.0000	0.0000
Methane	CH_4	85.7400	85.7400
Ethane	C_2H_6	11.8400	11.8400
Propane	C_3H_8	0.7800	0.7800
Isobutane	iso-C4H1O	0.0200	0.0200
Norbutane	nor-C4H1O	0.0200	0.0200
Isopentane	iso-C5H12	0.0000	0.0000
Norpentane	nor-C5H12	0.0000	0.0000
Hexane	C_6H_{14}	0.0000	0.0000
Heptane	C_7H_{16}	0.0000	0.0000
Nitrogen	N_2	1.0800	1.0800
Carbon Dioxide	CO_2	0.5200	0.5200
Hydrogen Sulfide	H_2S	0.0000	0.0000
Carbon Monoxide	CO	0.0000	0.0000
Hydrogen	H_2	0.0000	0.0000
Oxygen	O_2	0.0000	0.0000
Helium	HE	0.0000	0.0000
Neopentane	neo-C5H12	0.0000	0.0000
Octane	C_8H_{18}	0.0000	0.0000
Nonane	C_9H_{20}	0.0000	0.0000
Ethylene	C_2H_4	0.0000	0.0000
Propylene	C_3H_6	0.0000	0.0000
TOTAL (Volume %)		100.0000	100.0000

Fuel Makeup:	Jackson County Plant
Unit of Measure:	English

Calculated Fuel Properties

Caterpillar Methane Number:	73.1
Lower Heating Value (Btu/scf):	994
Higher Heating Value (Btu/scf):	1099
WOBBE Index (Btu/scf):	1253
THC: Free Inert Ratio:	61.5
Total % Inerts (% N2, CO2, He):	1.6%
RPC (%) (To 905 Btu/scf Fuel):	100%
Compressibility Factor:	0.997
Stoich A/F Ratio (Vol/Vol):	10.34
Stoich A/F Ratio (Mass/Mass):	16.44
Specific Gravity (Relative to Air):	0.629
Specific Heat Constant (K):	1.298

CONDITIONS AND DEFINITIONS
Caterpillar Methane Number represents the knock resistance of a gaseous fuel. It should be used with the Caterpillar Fuel Usage Guide for the engine and rating to determine the rating for the fuel specified. A Fuel Usage Guide for each rating is included on page 2 of its standard technical data sheet.

RPC always applies to naturally aspirated (NA) engines, and turbocharged (TA or LE) engines only when they are derated for altitude and ambient site conditions.

Project specific technical data sheets generated by the Caterpillar Gas Engine Rating Pro program take the Caterpillar Methane Number and RPC into account when generating a site rating.

Fuel properties for Btu/scf calculations are at 60F and 14.696 psia.

Caterpillar shall have no liability in law or equity, for damages, consequently or otherwise, arising from use of program and related material or any part thereof.

FUEL LIQUIDS
Field gases, well head gases, and associated gases typically contain liquid water and heavy hydrocarbons entrained in the gas. To prevent detonation and severe damage to the engine, hydrocarbon liquids must not be allowed to enter the engine fuel system. To remove liquids, a liquid separator and coalescing filter are recommended, with an automatic drain and collection tank to prevent contamination of the ground in accordance with local codes and standards.

To avoid water condensation in the engine or fuel lines, limit the relative humidity of water in the fuel to 80% at the minimum fuel operating temperature.

To:	Jeff Weiler Energy Transfer 800 Sonterra Blvd Suite 400 San Antonio, TX 78258	**Phone:** **Mobile:** **Fax:** **Email:**	210-403-7323 210-289-4550 210-403-7523 Jeff.Weiler@energytransfer.com
CC:	David Zenthoefer/MIRATECH Corporation		
From:	Debora Calderón MIRATECH Corporation 420 S 145th E Ave Mail Drop A Tulsa, OK 74108	**Phone:** **Fax:** **Email:**	918-933-6271 918-933-6268 dcalderon@miratechcorp.com

Project Reference:	Jackson County 3616
Proposal Number:	DZ-11-1913 Rev(1)
Date:	**8/1/2011**
Firm Quote For:	**30 days from Proposal Date**

Dear Jeff:

MIRATECH Corporation welcomes the opportunity to provide you with a proposal for an NSCR/SCR system. We are confident that your organization will benefit from selecting us for this project for the following reasons:

- **Experience.**
  - MIRATECH is the leader in providing NSCR, SCR & DPF systems; having more than 17,000 successfully operating units installed in North America, South America, Europe and Asia.
- **World-Class Technology.**
  - Consistently set the standards for Best Available Control Technology (BACT)
  - Simple, user-friendly control and communication technology; connects to any building's communication systems
- **U.S.-based Field Services & Support.**
  - Fast-response field service & technical support
  - Replacement components in stock in Tulsa, Oklahoma
  - In-house engineering & product support

The system offered for this project is in accordance with the data received or estimated from your company. The system is designed to provide emission reduction for oxides of nitrogen (NOx), carbon monoxide (CO), hydrocarbons (NMNEHC), and formaldehyde (CH2O) as listed on the System Specifications and Performance Warranty Data page. MIRATECH warrants the quoted performance based on the engine emission and operating data you have provided us and that is contained in this proposal. Please note that some engine assumptions were used and converter size may change based on actual engine data.

Once again, thank you for the opportunity to provide this proposal. If you have any questions, please do not hesitate to contact me. I will call you next week to confirm your receipt and satisfaction with this proposal.

Best Regards,

Debora Calderón
Inside Sales
MIRATECH Corporation

Engineer Sized By: Brett Fuller/MIRATECH Corporation

Quotation Summary

The prices are as follows:

SCR System

Components	QTY/Engine	Total QTY	Price/Engine	Total Price
Selective Catalytic Reduction Housing - *SP-CBL121-36*	1	3		
NSCR Housing & Catalyst - *ZCS-54x61-20/24-XH4B2*	2	6		
NSCR Housing & Catalyst - *SP-RHSIGA-84S3624x41-36-XH2B2*	1	3		
Mixing Section - *36" Mixing Section (2 Mixer)*	1	3		
SCR Control System - *ACIS II*	1	3		
Maintenance Pack - *ACIS II Maintenance Pack*	1	3		
Spare Parts - *ACIS II Recommended Spare Parts*	1	3		
System Total			**$444,292.83**	**$1,332,878.50**

Options Not Included In Price Above

Components	QTY/Engine	Total QTY	Price/Engine	Total Price
SCR Reactant Tank - *DW5250.ht.ins*	1/3	1	$13,689.50	$41,068.50
Reactant Tank Level Indicator - *TLI*	1/3	1	$1,079.83	$3,239.50

Technical Service

Service Contract	Available upon request.
Commissioning Labor Not To Exceed Estimate *Based on site readiness; rate sheet is attached.*	$31,975.00 total
Post Commissioning System Training	Available upon request.

Terms and Conditions

This offer is in strict adherence to the attached *MIRATECH Holdings Terms and Conditions for SCR Products, Rev 7 dated August 2009*.

Shipment

All equipment is Ex Works Tulsa, OK

Delivery

Submittal documents, including drawings requiring customer signature and manuals, within five (5) working days of receipt and acceptance of customer Purchase Order, and first progress payment. All documents and manuals available in electronic format upon request.

The following lead times specify the time from receipt of first progress payment and signed submittal document by MIRATECH to product ready to ship. Lead times shown are for quantities of 1 or 2 unless otherwise specified. **For quantities in excess of 2, please obtain a commitment from MIRATECH**.

System Ready To Ship: 12 – 18 Weeks

Payment Terms

Project Payment	Milestone	Net
30%	To release project for production	Due upon receipt of invoice
70%	Upon shipment availability	Due upon receipt of invoice
Technical Service		30 days

MIRATECH Corporation Scope of Supply

	Model Number	Quantity per Engine
NSCR Housing & Catalyst	**ZCS-54x61-20/24-XH4B2**	
NSCR Housing	ZCS-54x61-20/24-HSG	2
Oxidation Catalyst	ZXS-RE-FULL354XH	8
Blind Catalyst	ZXS-RE-FULLBLIND	4
Nut, Bolt, and Gasket Set	NBG-ZXS6	2
NSCR Housing & Catalyst	**SP-RHSIGA-84S3624x41-36-XH2B2**	
NSCR Housing	SP-RHSIGA-84S3624x41-36-HSG	1
Oxidation Catalyst	SP-RXS-RE-S3624XH	2
Blind Catalyst	SP-RXS-RE-S3624BLIND	2
Top Outlet Stack	SP-RXSIGA-TOP_STACK-36	1
Top Outlet Stack Bolts, Nuts, & Gasket	NBG-RXISGA-TOP_STACK-36	1
Selective Catalytic Reduction Housing	**SP-CBL121-36**	
SCR Housing	SP-CBL121-36	1
SCR Catalyst	RFV.1250.55.0150.450	242
SCR Control System	**ACIS II**	
SCR Controller	SNQ.lab.ops.no0100	1
Dosing Box	SEN10.lab	1
Redundant Reactant Pump	VPD350	1 per every 3 engines
Pump Controller	DPCU1.6.lab.gat	1 per every 3 engines
Reactant Filter	FILTER20	1
Injector	DEN20.700	1
Natural Gas Sample Probe	LS1075	1
Over Temperature Switch	UT	1
Temperature Sensor	TEA330	1
Air Compressor	CA20.lab	1
Mixing Section	**36" Mixing Section (2 Mixer)**	
Pre-Fabricated Mixing Section	36" Mixing Section (2 Mixer)	1
Flow Dresser	36" Flow Dresser	1
Dosing Mixer	36" Dosing Mixer	1
Static Mixer	36" Static Mixer	1
Mixing Section Injector Flange	36" Mixing Section Injector Flange	1
SCR Reactant Tank	**DW5250.ht.ins**	
Reactant Tank	DW5250.ht.ins	1 per every 3 engines (optional)
Spare Parts	**ACIS II Recommended Spare Parts**	
Recommended Spare Parts	SNQ Recommended Spare Parts	
Spare Part	Sample Gas Pump	1
	Gas Solenoid Valve	1
	Condensate Pump	1
	SEN10 Recommended Spare Parts	
Spare Part	Dosing Valve 3..20	1
	CA20 Recommended Spare Parts	
Spare Part	Compressor DT4.8	1
Maintenance Pack	**ACIS II Maintenance Pack**	
Maintenance Pack	SNQ Maintenance Pack	
Spare Part	ThermoElement - TE	1
	Injector Flange Gasket	1
	Sample Pressure Switch	2
	Condensate Pump Head	2

	Sample Gas Filter	6
	Enclosure Filter	2
	CA20 Maintenance Pack	
Spare Part	Compressor Vane Kit DT4.8	1
	Air Suction Filter CA20	1
	SEN10 Maintenance Pack	
Spare Part	Air Pressure Switch	1
	Dosing Valve 3..20	1
	DEX20.XXX Maintenance Pack	
Spare Part	Injector O-Ring DEN20 - Large	2
	Injector O-Ring DEN20 - Small	2
	Nozzle Gasket - DEN20	2
	Injector Nozzle - DEN20	2
	Air Adjustment Cap - DEN20	2
	Air Adjustment Ring 20L	2
	VPX350-4000 Maintenance Pack	
Spare Part	VPX350-4000 Filter Bag	2
Reactant Tank Level Indicator	**TLI**	
Reactant Tank Level Indicator	TLI	
Level Transmitter	LU20	1 per every 3 engines (optional)
Level Controller	LI55	1 per every 3 engines (optional)
Level Controller Enclosure	LM92	1 per every 3 engines (optional)

Customer Scope of Supply

Description
Support Structure
Foundation
Attachment to Support Structure (Bolts, Nuts, Levels, etc.)
Expansion Joints
Exhaust Piping
Inlet Pipe Bolts, Nuts, & Gasket
Outlet Pipe Bolts, Nuts, & Gasket
Insulation for Exhaust Piping
Power Input (230 VAC, 60 Hz, Single Phase)
Component Installation Including External Tubing and Wiring
Isolated Engine Load Signal to MIRATECH Equipment (4-20 mA)
Dry Contact (N.O.) for Engine Run Signal to MIRATECH Equipment
Heat Tracing of Reactant Lines (Required when Ambient Temperatures are Below 40 °F)
Heat Tracing of Sample Lines (Required when Ambient Temperatures are Below 32 °F)
Design for Structural Support and Thermal Expansion

Application Data

Project Information

Site Location:	Texas
Project Name:	Jackson County 3616
Application:	Gas Compression
Number of Engines:	3
Operating Hours per Year:	8760

Engine Specifications

Engine Manufacturer:	Caterpillar
Model Number:	G3616
Rated Speed:	1,000 RPM
Type of Fuel:	Natural Gas
Type of Lube Oil:	0.6 wt% sulfated ash or less
Lube Oil Consumption:	< 0.00027 gal/bhp-hr

Engine Cycle Data

Load	Speed	Power	Exhaust Flow	Exhaust Temp.	Fuel Cons.	NO_x	CO	NMHC	NMNEHC	CH_2O	PM_{10}	O_2	H_2O
%		*bhp*	*acfm (cfm)*	*F*	*BTU/bhp-hr*	*g/bhp-hr*	*g/bhp-hr*	*g/bhp-hr*	*g/bhp-hr*	*g/bhp-hr*	*g/bhp-hr*	*%*	*%*
100	Rated	4735	31646	876	7453	0.7	2.5	1.41	0.6	0.26		11.7	17

Raw Engine Emission Data

	g/bhp-hr	lb/MW-hr	ppmvd	ppmvd @ 15% O_2	lb/hr	g/kW-hr	tons/yr
NO_x	0.70	2.07	98	63	7.31	0.94	32.01
CO	2.50	7.39	576	370	26.10	3.35	114.31
NMNEHC	0.60	1.77	241	155	6.26	0.80	27.43
CH_2O	0.26	0.77	56	36	2.71	0.35	11.89

% O_2	11.7
H_2O Assumption	17.0

System Specifications and Performance Warranty Data

SCR System Specifications (SP-CBL121-36, ZCS-54x61-20/24-XH4B2, SP-RHSIGA-84S3624x41-36-XH2B2, 36" Mixing Section (2 Mixer), ACIS II, ACIS II Maintenance Pack, ACIS II Recommended Spare Parts)

Design Exhaust Flow Rate:	31,646 acfm (cfm)
Design Exhaust Temperature[1]:	876°F
SCR Catalyst Volume:	87 cubic feet
SCR Catalyst Space Velocity:	8,526 1/hr
System Pressure Loss:	10.0 inches of WC (Fresh)
Sound Attenuation:	35-40 dBA insertion loss
Exhaust Temperature Limits:	572 – 986°F (catalyst inlet); 986°F (catalyst outlet)
Reactant:	Urea
Percent Concentration:	32.5%
System Dosing Capacity:	10 L/hr
Estimated Reactant Consumption:	2 gal/hr (7 L/hr) / Per Engine

Post System Emission Data

	g/bhp-hr	lb/MW-hr	ppmvd	ppmvd @ 15% O_2	lb/hr	g/kW-hr	tons/yr
NO_x	0.07	0.21	10	6	0.73	0.09	3.20
CO	0.13	0.37	29	18	1.30	0.17	5.72
NMNEHC	0.24	0.71	97	62	2.51	0.32	10.97
CH_2O	0.02	0.05	4	3	0.19	0.02	0.83
NH_3	0.08	0.24	31	20	0.86	0.11	3.75

Calculated Percent Reductions

	% Reduction
NOx	90.0
CO	95.0
NMNEHC	60.0
CH2O	93.0

Equipment Details

Selective Catalytic Reduction Housing Details (SP-CBL121-36)

SCR Housing Details

• Model Number:	SP-CBL121-36
• Quantity²:	1
• Number of Catalyst Layers:	2.0
• Number of Spare Catalyst Layers:	0
• Number of Catalyst Blocks per Layer:	121
• Material:	Carbon Steel
• Paint:	None
• Inlet Pipe Size & Connection:	36 inch FF Flange, 150# ANSI standard bolt pattern
• Outlet Pipe Size & Connection:	36 inch FF Flange, 150# ANSI standard bolt pattern
• Door Location:	Right
• Dimensions:	75.250" H x 73.500" W x 123" L
• Weight Without Catalyst:	2,790 lbs
• Weight Fully Loaded With Catalyst:	7,892 lbs
• Insulation:	None

SCR Catalyst Details

• Model Number:	RFV.1250.55.0150.450
• Quantity²:	242
• Catalyst Dimensions:	5.91" W x 5.91" H x 17.72" L
• Catalyst Optimum Temperature Range³:	752 – 887°F

NSCR Housing & Catalyst Details (ZCS-54x61-20/24-XH4B2)

NSCR Housing Details	ZCS-54x61-20-24 SD
• Model Number:	ZCS-54x61-20/24-HSG
• Quantity²:	2
• Material:	Carbon Steel
• Paint:	Standard High Temperature Black Paint
• Diameter:	54 inches
• Inlet Pipe Size & Connection:	20 inch FF Flange, 150# ANSI standard bolt pattern
• Outlet Pipe Size & Connection:	24 inch FF Flange, 150# ANSI standard bolt pattern
• Overall Length:	140 inches
• Weight Without Catalyst:	1,733 lbs
• Weight Including Catalyst:	1,933 lbs
• Instrumentation Ports:	2 inlet/2 outlet (1/2" NPT)

Oxidation Catalyst Details

• Model Number:	ZXS-RE-FULL354XH
• Quantity²:	8

Blind Catalyst Details

• Model Number:	ZXS-RE-FULLBLIND
• Quantity²:	4

Nut, Bolt, and Gasket Set Details

• Model Number:	NBG-ZXS6
• Quantity²:	2

NSCR Housing & Catalyst Details (SP-RHSIGA-84S3624x41-36-XH2B2)

Equipment Details (continued)

NSCR Housing & Catalyst Details (SP-RHSIGA-84S3624x41-36-XH2B2) (continued)

NSCR Housing Details

• Model Number:	SP-RHSIGA-84S3624x41-36-HSG
• Quantity²:	1
• Material:	Carbon Steel
• Paint:	Standard High Temperature Black Paint
• Diameter:	84 inches
• Inlet Pipe Size & Connection:	36 inch FF Flange, 150# ANSI standard bolt pattern
• Inlet Location:	Side
• Inlet Height:	200 inches
• Outlet Pipe Size & Connection:	36 inch FF Flange, 150# ANSI standard bolt pattern
• Outlet Location:	Top
• Overall Stack Height:	75 feet
• Instrumentation Ports:	2 pre-catalyst / 2 post-catalyst / 1 outlet (2" NPT)

Oxidation Catalyst Details

• Model Number:	SP-RXS-RE-S3624XH
• Quantity²:	2
• Weight:	92 lbs

Blind Catalyst Details

• Model Number:	SP-RXS-RE-S3624BLIND
• Quantity²:	2
• Weight:	50 lbs

Top Outlet Stack Details

• Model Number:	SP-RXSIGA-TOP_STACK-36
• Quantity²:	1

Top Outlet Stack Bolts, Nuts, & Gasket Details

• Model Number:	NBG-RXISGA-TOP_STACK-36
• Quantity²:	1

Mixing Section Details (36" Mixing Section (2 Mixer))

Pre-Fabricated Mixing Section Details	36" Mixing Section (2 mixer) SD
• Model Number:	36" Mixing Section (2 Mixer)
• Quantity²:	1
• Material:	Carbon Steel w/ 304 SS Hydrolysis Section
• Overall Length:	168 inches
• Weight:	1128 lbs

Flow Dresser Details

• Model Number:	36" Flow Dresser
• Quantity²:	1
• Weight:	128 lbs

Dosing Mixer Details

• Model Number:	36" Dosing Mixer
• Quantity²:	1
• Weight:	47 lbs

Static Mixer Details

• Model Number:	36" Static Mixer
• Quantity²:	1
• Weight:	55 lbs

Equipment Details (continued)

Mixing Section Details (36" Mixing Section (2 Mixer)) (continued)

Mixing Section Injector Flange Details

- Model Number: 36" Mixing Section Injector Flange
- Quantity²: 1
- Weight: 4 lbs

SCR Control System Details (ACIS II)

SCR Controller Details — SNQ SD

- Model Number: SNQ.lab.ops.no0100
- Quantity²: 1
- Overall Dimensions: 23.425 W x 29.724 H x 13.652 D
- Weight: 132 lbs

Dosing Box Details — SEN10 SD

- Model Number: SEN10.lab
- Quantity²: 1
- Overall Dimensions: 15.75 W x 15.75 H x 6.562 D
- Weight: 27 lbs

Redundant Reactant Pump Details — VPD350 SD

- Model Number: VPD350
- Quantity²: 1 per every 3 engines
- Overall Dimensions: 75.591 W x 27.677 H x 23.622 D
- Weight: 254 lbs

Pump Controller Details — DPCU SD

- Model Number: DPCU1.6.lab.gat
- Quantity²: 1 per every 3 engines
- Overall Dimensions: 25.428 W x 31.496 H x 15.384 D
- Weight: 132 lbs

Reactant Filter Details

- Model Number: FILTER20
- Quantity²: 1

Injector Details

- Model Number: DEN20.700
- Quantity²: 1
- Weight: 9 lbs

Natural Gas Sample Probe Details

- Model Number: LS1075
- Quantity²: 1
- Weight: 0.94 lbs

Over Temperature Switch Details

- Model Number: UT
- Quantity²: 1
- Weight: 9 lbs

Temperature Sensor Details

- Model Number: TEA330
- Quantity²: 1
- Weight: 3 lbs

Equipment Details (continued)

SCR Control System Details (ACIS II) (continued)

Air Compressor Details	CA20 SD
• Model Number:	CA20.lab
• Quantity²:	1
• Overall Dimensions:	9.842 W x 26.772 H x 15.748 D
• Weight:	26 lbs

Maintenance Pack Details (ACIS II Maintenance Pack)

Maintenance Pack Details	
• Model Number:	SNQ Maintenance Pack
• Quantity²:	1
Maintenance Pack Details	
• Model Number:	CA20 Maintenance Pack
• Quantity²:	1
Maintenance Pack Details	
• Model Number:	SEN10 Maintenance Pack
• Quantity²:	1
Maintenance Pack Details	
• Model Number:	DEX20.XXX Maintenance Pack
• Quantity²:	1
Maintenance Pack Details	
• Model Number:	VPX350-4000 Maintenance Pack
• Quantity²:	1

Spare Parts Details (ACIS II Recommended Spare Parts)

Recommended Spare Parts Details	
• Model Number:	SNQ Recommended Spare Parts
• Quantity²:	1
Recommended Spare Parts Details	
• Model Number:	SEN10 Recommended Spare Parts
• Quantity²:	1
Recommended Spare Parts Details	
• Model Number:	CA20 Recommended Spare Parts
• Quantity²:	1

SCR Reactant Tank Details (DW5250.ht.ins)

Reactant Tank Details	DW5250 SD
• Model Number:	DW5250.ht.ins
• Quantity²:	1 per every 3 engines
• Material:	Cross-Linked Polyethylene
• Tank Dimensions:	121.5 D x 154 H
• Capacity:	5000 US Gallons
• Weight:	1753 lbs
• Wall Construction:	Double
• Insulation:	Nominal 2" of Urethane Spray Foam w/ Mastic Coating
• Heat Trace:	Included
• Seismic Tie Downs:	None

Reactant Tank Level Indicator Details (TLI)

Equipment Details (continued)

Reactant Tank Level Indicator Details (TLI) (continued)

Reactant Tank Level Indicator Details

- Model Number: TLI
- Quantity[2]: 1 per every 3 engines

Special Notes/Conditions

1 Carbon steel housings are suitable for use in all applications where the housing will not be insulated. Carbon steel housings may only be insulated in applications where the exhaust temperature does not exceed 900°F. If your application requires insulation with an engine exhaust temperature exceeding 900°F, a stainless steel housing is required. Customer installed insulation on carbon steel housings in applications where exhaust temperature exceeds 900°F voids any MIRATECH product warranty.

2 Quantities are per engine.

3 SCR units require a minimum temperature of 572°F (300°C) and a maximum temperature of 986°F (530°C). Several catalyst formulations are available with different optimum operating temperatures. The optimum operating temperature for this application is listed. Operating outside of the optimum range will change the reactant consumption and could cause damage to the catalyst.

- A packed silencer installed upstream of the MIRATECH catalyst system will void MIRATECH's limited warranty.
- Final catalyst housings are dependent on engine output and required emission reductions. Changes may be made to optimize the system design at the time of order.
- Any drawings included with this proposal are preliminary in nature and could change depending on final product selection.
- Any sound attenuation listed in this proposal is based on housing with catalyst elements installed.

Domestic Onshore Technical Service Rate Schedule

The Day Rate is charged for supervision of work performed over and above the scope of an installation or services contract. MIRATECH standard Terms and Conditions of Sale apply to all activities.

Technical Services Supervisor Day Rate	**$1,200.00**

Additional Information

- **The standard Day Rate is for an 8-hour, onshore, non-holiday, weekday and is the minimum charge.**
- **Charges for greater than 8 hours but less than 12 hours in a single calendar day** - The number of hours of supervision in a single calendar day divided by 8 and multiplied by the standard Day Rate times any applicable multipliers for Weekends and Holidays (see below). (example - 10 hours of supervision in a single day - 10/8 x $1,200 = $1,500)
- **Charges for greater than 12 hours per day** - Actual time worked over 12 hours per day will be charged at a rate of $225.00 per hours or 1.5 times the calculated hourly rate, which ever is greatest.
- **Travel Time** - actual hours traveled each way divided by 8 and multiplied by the standard Day Rate. No multipliers are applicable. (example - 5 hours traveled to site - 5/8 x $1,200 = $750)
- **Saturday** - 1.5 times the standard Day Rate
- **Sundays** - 2 times the standard Day Rate
- **All National Holidays** - 3 times the standard Day Rate

Expense Invoicing Rates

MIRATECH Actual Cost plus 5% - Lodging, phone, meals, parking, air travel, rental cars and incidental costs.

Company Vehicle Mileage at:	**$ 1.00 per mile**
Portable Exhaust Gas Analyzer	**$ 400.00/calendar day**
Special Tools and Equipment rental	**cost plus 15%**

420 S. 145th E. Avenue, Mail Drop A, Tulsa, OK 74108-1305
Phone Number (800) 640-3141 FAX Number (918) 622-3928
www.MIRATECHcorp.com

GENERAL TERMS AND CONDITIONS OF SALE
For SCR Products and Systems

1. **Integration** The General Terms and Conditions of Sale contained herein shall be deemed a material part of any sale or proposed sale of HUG Engineering ("HUG") SCR products by MIRATECH Holdings, LLC ("Seller") to ________________________________ ("Purchaser") and, unless and only to the extent specifically excluded therein, shall be a material part of any subsequent letter of authorization, contract, purchase order, acceptance agreement, sale or other agreement ("Contract") between Seller and Purchaser, with respect to all products, equipment, services and/or parts relating thereto (hereinafter referred to as the "Product").

2. **Compliance** To Seller's knowledge, Seller has complied with all applicable laws and regulations including, but not limited to, the Fair Labor Standards Act, the Civil Rights Act of 1964, the Equal Employment Opportunity Act of 1972, as respectively amended, Executive Orders 11246, 11375 and 11141 (Title 41, Chapter 60, Code of Federal Regulations), the Vietnam Era Veterans Readjustment Act of 1974, and all amendments thereto and regulations, rules and orders there under, as amended or superseded and all of the foregoing are made a part hereof by reference and incorporated herein as though fully set forth herein. Purchaser understands and agrees that the foregoing sentence is for Purchaser's information stating that which Seller strives to achieve and is not made as a covenant, warranty or representation and is not meant to create or permit, nor shall it be construed as creating or permitting any enforceable rights hereunder for Purchaser or any other person or entity. All standards promulgated with respect to noise or air control are specifically excluded hereunder.

3. **Title, Risk of Loss, Security Interest** Title and risk of loss or damage to the Product shall pass to Purchaser under tender of delivery Ex-Works Tulsa unless expressly stipulated otherwise, regardless of when partial or final payment is to be made by Purchaser. Notwithstanding the foregoing, a purchase money security interest in the Product or any replacement thereof shall remain in Seller, regardless of mode of attachment to realty or other property, until full payment has been made therefore and collected by Seller.

4. **Inspection, Rejection, Remedy** Purchaser shall have the right to reasonable inspection of the Product after delivery to destination, which inspection shall be completed within ten (10) days of the date of delivery to such destination. Any rejection by Purchaser as to part or all of the Product shall be in writing, specifically stating the non-conformities thereof. In such event, Seller shall have a reasonable period of time to determine the validity of and, if necessary, to correct the non-conformities forming the basis of the Purchaser's rejection or, at Seller's option and if appropriate, to replace part or all of the Product. Purchaser's failure to make rejection as herein stated, or to allow Seller to cure Purchaser's objections, shall be deemed to conclusively establish acceptance by Purchaser of the Product.

5. **Time, Forced Majeure** Seller may, from time to time, quote delivery dates to Purchaser. Such dates shall be interpreted as estimated and in no event shall such dates be construed as falling within the meaning of "time is of the essence." Seller shall not be liable for loss, damage, detention, or delay due to war, riots, civil insurrection or acts of the common enemy, fire, flood, severe weather conditions at Seller's premises or outside fabrication sites, strikes or other labor difficulties, acts of civil or military authority including governmental law, orders, priorities or regulations, acts of Purchaser, embargo, car shortage, wrecks or delay in transportation, inability to obtain necessary labor, materials or manufacturing facilities from usual sources, faulty forgings or castings, or other causes beyond the reasonable control of Seller. In the event of delay in performance due to any such cause, the date of delivery or time for completion shall be adjusted to reflect the actual length of time necessary to properly reflect the delay without change to the purchase price. In the event of such delay or default in delivery, Seller shall complete work in progress and/or make delivery as soon as reasonably practicable. Upon completion and delivery of the Product to Purchaser, after such delay in delivery, the obligation of Purchaser for payment shall be completely reinstated.

6. **Taxes** Prices quoted by Seller do not include any federal, state or local property, license, privilege, sales, use, excise, gross receipts or other like taxes which may now or hereafter be applicable to, measured by, or imposed upon this transaction, the Product, its sale, its value, its use or any services performed in connection therewith. Such taxes shall be paid by Purchaser or, if paid by Seller, shall be itemized separately to Purchaser, who shall make prompt payment therefore to Seller.

7.1 **Limited Warranty** Subject to the exclusions contained herein, HUG warrants that the Product shall be free of defects in material and workmanship for a period of twenty-four (24) months from the date the Product is placed in operation or twenty-six (26) months from the date the Product is complete and ready for shipment, whichever shall first occur, and provided Purchaser shall, within such period, notify Seller in writing of such defect(s) and fully cooperate with Seller in pursuing the remedying thereof. Should any failure to conform to this warranty be reported to Seller within said period, Seller shall, upon Purchaser promptly notifying Seller in writing thereof, correct such nonconformity by suitable repair to the Product or, at Seller's option, furnish replacement parts C.I.P. Seller's point of shipment, provided Purchaser has restored the Product to the "as shipped" condition prior to installation and has installed, maintained and operated the Product in accordance with standard industry practices and has complied with the specific recommendations of Seller respecting the Product. Accessories or other parts of the Product furnished by Seller, but manufactured by others, shall carry whatever warranty, if any, the manufacturers thereof have given to Seller and which can be passed on to Purchaser. Purchaser agrees to look solely to HUG and other such manufacturers or suppliers of such accessories or parts for any warranty, repair or product liability claims arising out of the performance, condition or use of such accessories or parts. Seller agrees to cooperate in furnishing assignments of its rights thereto to Purchaser from such manufacturers and suppliers. Seller shall not be liable for any repairs, replacements or adjustments to the Product or any costs of labor performed by Purchaser without Seller's prior written approval. Seller's warranty shall expire in the event the Product is misused, neglected or operated other than for its intended purpose. Except as stated herein, Seller makes no performance warranty of any kind respecting the Product. The effects of corrosion, erosion and normal wear and tear are specifically excluded from Seller's warranty. In the event performance warranties are expressly included, in writing, Seller's obligation shall be to correct non-conformities in the manner and for the period of time provided herein above.

Seller's warranty shall expire in the event: an A-36 carbon steel housing provided by Seller is insulated and operated with an inlet operating temperature to the housing greater than 900 deg F; or a component supplied by others that is upstream of the Seller's provided scope damages the Seller provided scope.

Correction by Seller of non-conformities, whether patent or latent, in the manner and for the period of time provided above, shall constitute fulfillment of all liabilities of Seller for such non-conformities, whether based on contract, warranty, negligence, indemnity, strict liability or otherwise with respect to or arising out the Product. Seller shall in no event be liable for consequential damages.

7.2 **Limited Warranty, Conditions** Throughout the Warranty Period, HUG warrants that the Product will achieve the emissions levels set forth in the Proposal referenced in and attached to the Contract between Seller and Purchaser, subject to the conditions that

a. the Product is operated and maintained at all times in accordance with the Seller's written instructions;
b. the Purchaser's equipment is operated and maintained at all times in accordance with all manufacturer's instructions and guidelines;
c. the Purchaser's equipment, during operation, shall never exceed the raw emission rate, the flow rate or temperature levels set forth in the Proposal;
d. the Purchaser's equipment shall never fall below the lower temperature limits stated in the Proposal;
e. The Purchaser will operate the equipment so the engine emissions & temperature are as stated in the proposal and:
    1. the NO_x, CO, VOC/NMNEHC, O_2, and $PM_{2.5}$ will not fluctuate more than 2% from the Proposal value;
    2. the exhaust flow rate will not fluctuate more than 2% from the Proposal value;
    3. the exhaust temperature into the catalyst will not fluctuate more than 10°F from the Proposal value.

All operating parameters, excluding raw and post SCR emission levels as well as engine exhaust flow rate, are recorded and logged hourly.

Emissions levels, temperature and flow rates from Purchaser's equipment and the SCR Product discharge point shall be tested at the Purchaser's expense, in accordance with a mutually agreed test procedure and protocol consistent with accepted industry practices.

If the above conditions are met and the Product fails to achieve the output performance stated in the Proposal within the Warranty Period, HUG will replace or modify and adjust its Product as needed to meet such output performance standards. Purchaser is required to notify the Seller in writing of the specific defect and provide Seller with complete documentation of the defect and satisfaction of all conditions, a - f, of this article. If Seller is unable to achieve the output performance standards under the Contract conditions within a mutually agreed to time period, Purchaser may rescind the sale, and Seller shall return the purchase price.

7.3 **Warranty Disclaimer** **SELLER MAKES NO OTHER WARRANTY OR REPRESENTATION OF ANY KIND WHATSOEVER, EXPRESSED OR IMPLIED, EXCEPT THAT OF GOOD TITLE TO THE PRODUCT, AND ALL IMPLIED WARRANTIES, INCLUDING ANY WARRANTY OF MERCHANTABILITY AND/OR FITNESS FOR A PARTICULAR PURPOSE, ARE HEREBY DISCLAIMED.**

8. **Remedies Exclusive** The remedies of Purchaser set forth herein are exclusive. The total liability of Seller with respect to the performance and other matters related to the manufacture, sale, delivery, installation, repair or technical direction thereof, whether based on contract, warranty, negligence, indemnity, strict liability or otherwise, shall in no event exceed the purchase price of the particular component of the Unit of Product upon which such liability is based, and not the aggregate of all Products covered by any agreement or document between Seller and Purchaser. Seller shall, in no event, be liable to Purchaser, any successors in interest or any beneficiary or assignee of Purchaser, for any consequential, incidental, indirect, special or punitive damages or any defect in, or failure or malfunction of, the Product or particular component of the Unit of Product, whether based upon lost goodwill, lost profits or revenue, interest, work stoppage, impairment of other goods, loss by reason of shutdown or non-operation, increased expenses of operation of Product, loss of use of power system, costs of purchase of replacement power or claims of Purchaser or customers of Purchaser for service interruption, whether or not such loss or damage is based on contract, warranty, negligence, indemnity, strict liability or otherwise. Purchaser warrants that the Product is purchased for, and will be used for, business purposes only by qualified and properly trained personnel.

9. **Set-off** Purchaser shall not have the right to retain, back charge, or set off against any amounts which may be or become payable by it to Seller or otherwise, for amounts which Seller may allegedly or in fact owe Purchaser whether arising hereunder or otherwise.

10. **Governing Law - Venue** The rights and obligations of Purchaser and Seller shall be construed in accordance with and governed by the laws of the State of Oklahoma, notwithstanding any conflict of law provisions which would have the effect of making the law of another state applicable. Seller and Purchaser agree that venue respecting any and all disputes between Purchaser and Seller with regard to the Product shall be Tulsa County, Oklahoma.

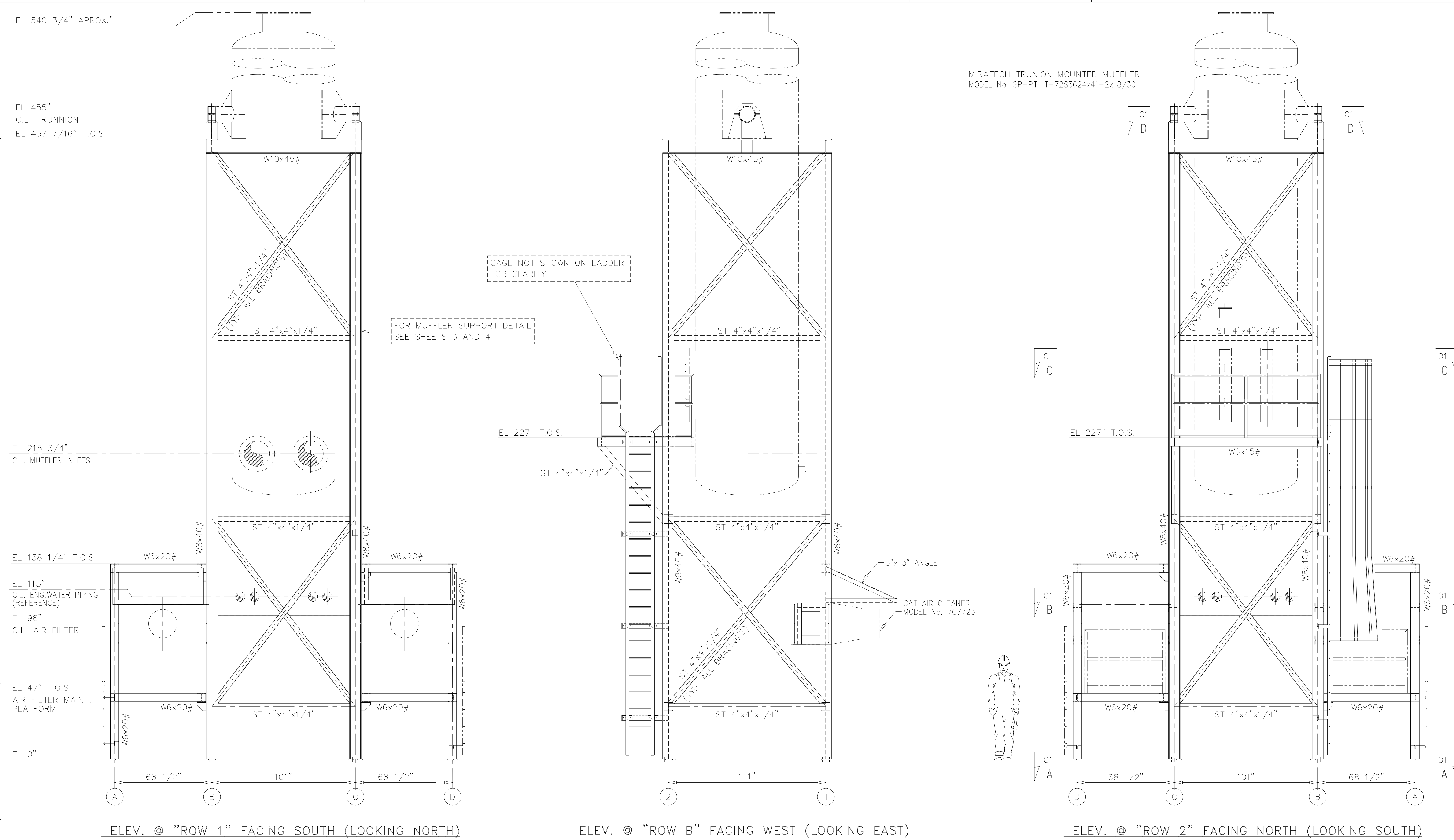
11. **No Waiver** No waiver by Seller of any breach of any obligation of Purchaser set forth in the General Terms and Conditions herein shall be construed as a waiver of any succeeding breach of the same or of any covenant or condition, and in no event shall this provision itself be waived.

12. **Payment** Payment terms shall be as stated in the Contract between Seller and Purchaser. Terms of payment are net ten (10) days from date of invoice, unless otherwise agreed in writing.

13. **Cancellation of Contract before Delivery** In the event the Purchaser cancels the Contract after the date of such Contract, Purchaser agrees to pay the following charge as liquidated damages in lieu of actual damages, it being understood and agreed between the parties that actual damages to Seller would be impractical or extremely difficult, time consuming and expensive to ascertain:

% of Quoted Manufacturing Period Elapsed From Date of Contract to Time of Cancellation	% of Sales Price Not Including Shipping Costs
0 to 33 1/3%	50%
33 1/3 to 50%	75%
50 to 66 2/3%	85%
66 2/3 to 80%	95%
80% to 100%	100%

14. **Conflicting Provisions, Modifications** In case of any conflict, the General Terms and Conditions contained herein shall supersede any and all specifications and/or other terms and conditions previously supplied by Purchaser in connection with or upon a letter of authorization, purchase order or any other agreement, as well as any custom, prior conduct or course of dealing. No agreement, oral representation or other understanding any way modifying or amending the General Terms and Conditions, or having the effect of enlarging the obligations of Seller hereunder, shall be binding upon the Seller unless such modification is clear, certain and in writing in the form of an amended letter of authorization, purchase order or other agreement duly executed by Purchaser and an authorized representative of Seller.



NOTES:

PROPRIETARY AND CONFIDENTIAL

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REV	DESCRIPTION	DRAWN	CHK'D	APPR	DATE
1	AS BUILT	MVB	GB	GB	04/05/10
0	ISSUED FOR CONSTRUCTION	DA	TA	T.A.	7/17/09

Standard Equipment Company

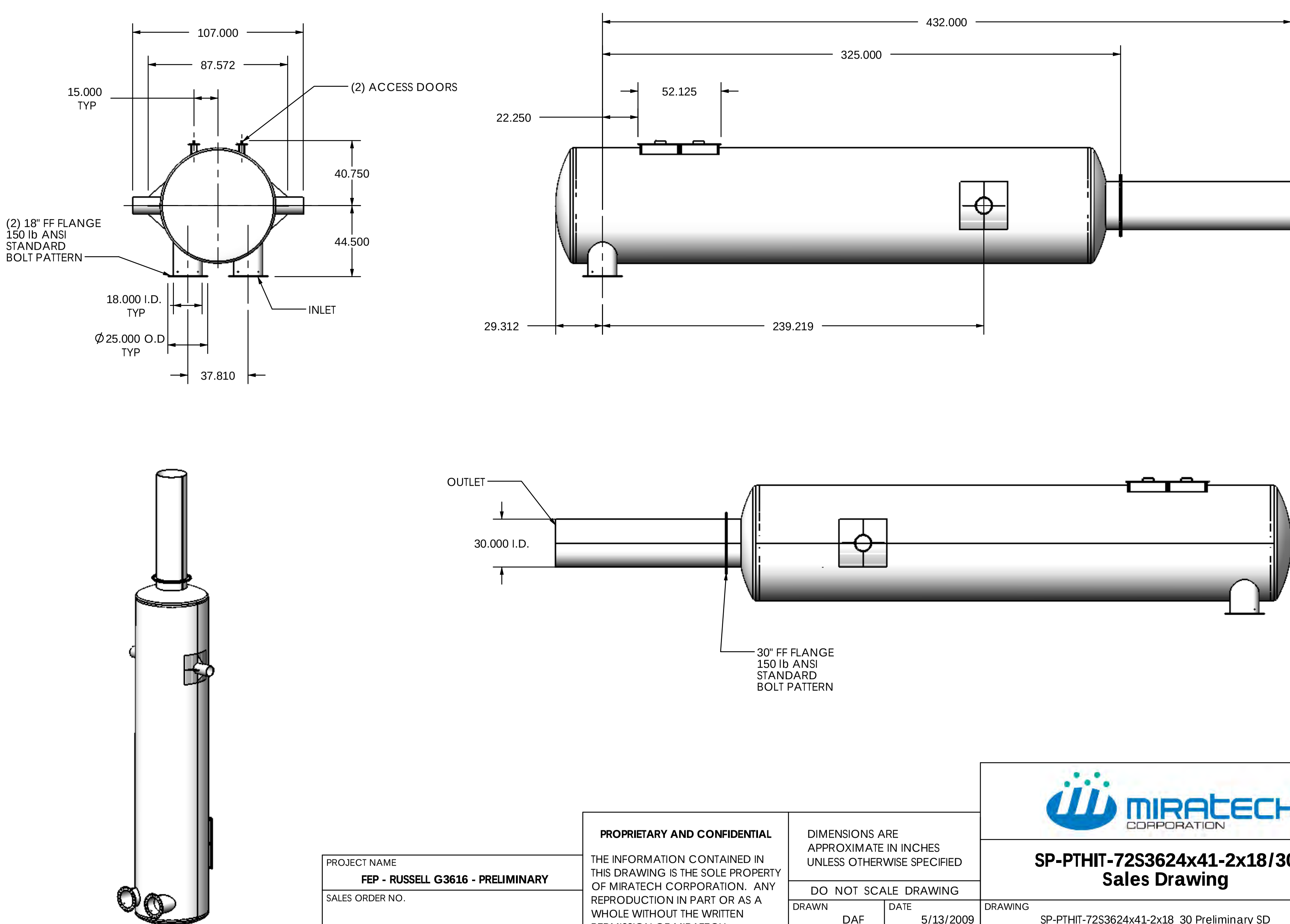
Energy Products and Services L.P.

JOB No.: 2599	ITEM TAG No.:
DRAWN BY: JR	CHECKED BY: AA
DATE 06/19/09	SCALE 3/8"-1'-0"

D

MUFFLER/CAT AIR FILTER SUPPORT
GENERAL ARRANGEMENT ELEVATIONS
CATERPILLAR G3616
TIGER PIPELINE
2599

DWG. No. 2599-301-02 | SHEET 2 OF 11 | REV 1



PROJECT NAME
FEP - RUSSELL G3616 - PRELIMINARY

SALES ORDER NO.

FABRICATION P.O.

PROPRIETARY AND CONFIDENTIAL

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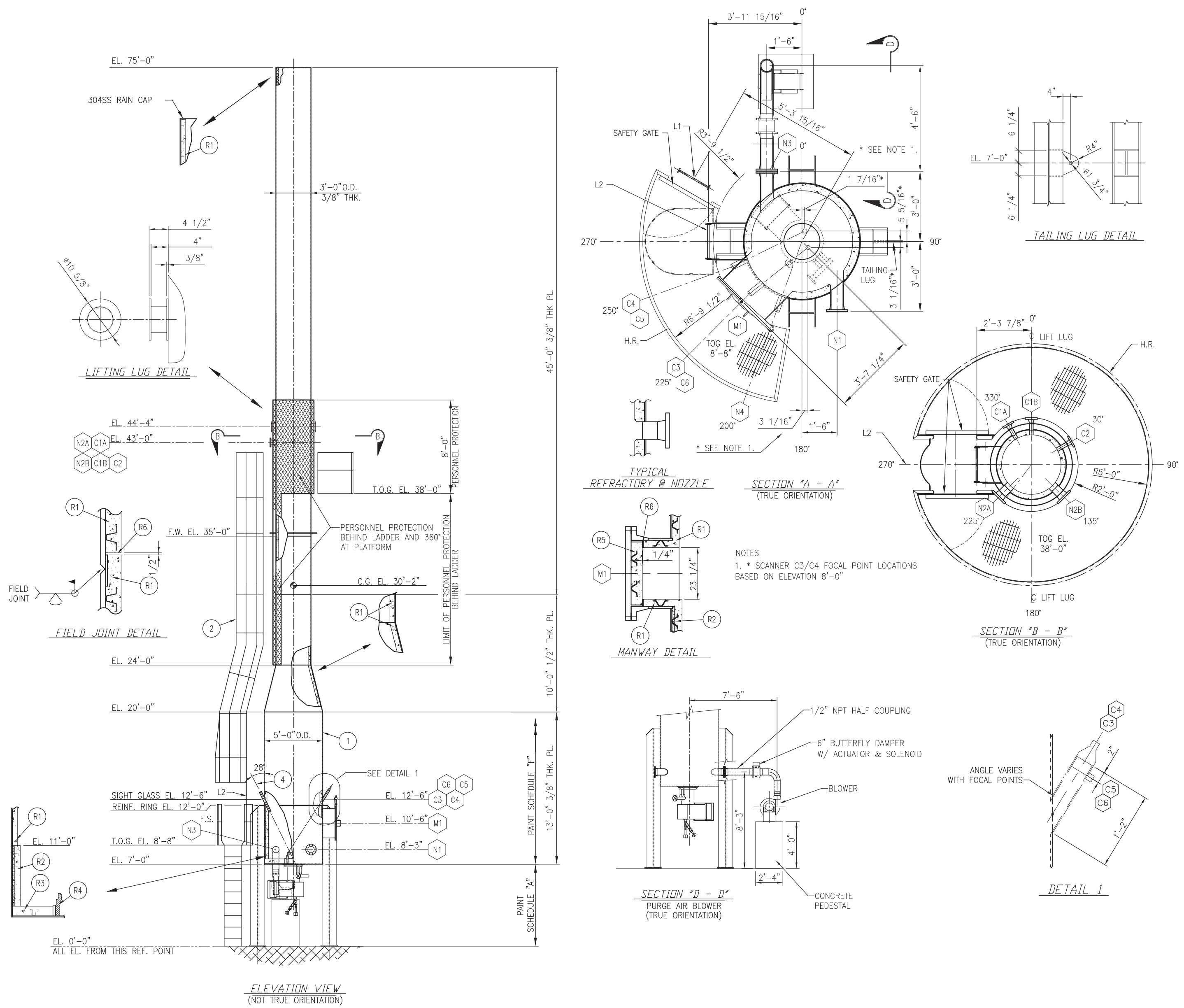
DRAWN	DATE
DAF	5/13/2009
REVIEWED BY	DATE
-	-

MIRATECH CORPORATION

SP-PTHIT-72S3624x41-2x18/30
Sales Drawing

DRAWING			REV
SP-PTHIT-72S3624x41-2x18_30 Preliminary SD			4
SIZE A	SCALE 1:86		SHEET 1 OF 1



– NOZZLE LEGEND –

ITEM	QTY	DESCRIPTION	SIZE	RATING	TYPE	MATERIAL
N1	1	ACID GAS INLET FLANGE	6"	150#	RFWN	A-182-F304
N2A/B	2	EPA SAMPLE PORTS	4"	150#	RFWN	A-105
N3	1	HANDHOLE w/ BLIND	6"	150#	RFWN	A-182-F304
N4	1	SIGHT PORT CONNECTION	2"		SCH 40	A-53
C1A/B	2	THERMOCOUPLE	4"	150#	RFWN	A-105
C2	1	O2 ANALYZER CONNECTION	1"	150#	RFWN	A-105
C3/C4	2	SCANNER CONNECTION	1"		NPT	A-105
C5/C6	2	PURGE CONNECTION	1/2"		NP	A-105
M1	1	MANWAY w/ DAVIT	30"		PL FLG	A-36

– PARTS LIST –

ITEM	QTY	DESCRIPTION	PART NO.	MATERIAL
1	1	CO2 VENT GAS THERMAL OXIDIZER	-//-	A-36
2	1	LADDERS & PLATFORMS	-//-	A-36
3	1	GLSF-8 FREE JET GAS BURNER	-//-	-//-
4	1	2" DIA. SIGHT GLASS w/ PURGE CONNECTION	-//-	-//-
5	1	2" DIA. SIGHT GLASS ASSEMBLY w/ GASKET	-//-	-//-
6	1	MANWAY GASKET	-//-	-//-
7	1	PURGE AIR FAN	-//-	-//-

– REFRACTORY LEGEND –

ITEM	DESCRIPTION
R1	3" THK 2400°F INSULATING CASTABLE w/ 2 1/4" TALL 310SS ANCHORS ON 6" CENTERS
R2	3" THK 3000°F HEAVY CASTABLE BACKED w/ 1" THK 2400°F INSULATING CASTABLE w/ 3 1/8" TALL 310SS ANCHORS ON 9" CENTERS
R3	5 1/2" THK 3000°F HEAVY CASTABLE w/ 3 1/4" TALL 310SS ANCHORS ON 9" CENTERS
R4	BURNER TILE
R5	4" THK 3000°F HEAVY CASTABLE w/ 3" TALL 310SS ANCHORS ON 9" CENTERS
R6	HI-TEMP CERAMIC FIBER – 1" THK 2200°F COMPRESSED TO 1/2"
	REFRACTORY SHOP DRIED TO 600°F

– DESIGN & GENERAL NOTES –

1.	DESIGNED PER:
2.	DESIGN TEMPERATURE:
3.	OPERATING TEMPERATURE:
4.	PAINT PER CUSTOMER SPECIFICATIONS
5.	ESTIMATED TOTAL STACK WEIGHT: 37,418 LBS

** PRELIMINARY DRAWING **

JOBSITE: LONG BEACH, CA
END USER: THUMSCO
S.O. NO.: 16340 P.O. NO.:

ZEECO, INC.
22151 EAST 91st STREET
BROKEN ARROW, OK 74014
PHONE: (918) 258-8551
FAX: (918) 251-5519
www.zeeco.com
sales@zeeco.com

GENERAL ARRANGEMENT
THERMAL OXIDIZER

FOR: WORLEY PARSONS

DRAWN	DATE	CHK	APP	SCALE	REV	DRAWING NUMBER
SLR	27DEC10	TWD	TWD	NONE	A	16340-G01001

Representative Equipment: The burner management system vendor has not yet been selected.

Patton

BURNER MANAGEMENT SYSTEM

Patton Burner Management System brings advanced control, monitoring, and communication capabilities to oilfield fired equipment applications, enabling operators to more safely and reliably manage their process while ensuring continuous compliance with EPA regulations.

BENEFITS

- 12VDC solar-powered system
- Solid-state UV flame detector - low power consumption and high reliability
- Data logging: two years of historical data
- Modbus™ communications via RS232, RS485 or Ethernet
- Standard and custom configurations available
- Designed for installation in Class I, Division 2 areas

Rawson energy services

Representative Equipment: The burner management system vendor has not yet been selected.

Patton
BURNER MANAGEMENT SYSTEM

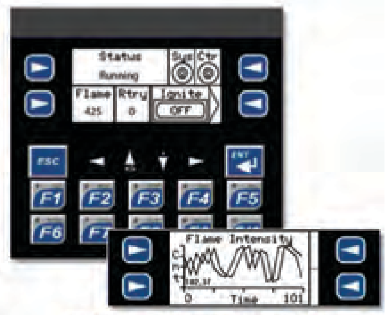
P100
Single Burner • Compact Igniter Setup
ZEL Control Panel • 50W Solar Panel • 55Ah Battery
Two Stainless-Steel Explosion Proof Solenoid Valves
One Flame Detector

P200
Single Burner Igniter Setup
OCS Logging Control Panel • 50W Solar Panel
Two Stainless Steel Explosion Proof Solenoid Valves
55Ah Battery • One Flame Detector

P300
Single Burner Igniter Setup • OCS Logging Control Panel
Analog and Digital In/Out Level/Temp/Pressure Control & Monitoring
Fuel Control MOV • Two 30W Solar Panels • Three 105 Ah Batteries
Three Stainless-Steel Explosion Proof Solenoid Valves
One Flame Detector • Extra Battery Box • Low Voltage Disconnect

P400
Dual Burner Igniter Setup • OCS Logging Control Panel
Analog and Digital In/Out Level/Temp/Press Control & Monitoring
Pilot on Demand: Standard (Fuel Control MOV: Optional)
Three 105 Ah Batteries • Two 130W Solar Panels• Extra Battery Box
Four (6 for Fuel Control) Stainless-Steel Explosion Proof Solenoid Valves
Two Flame Detectors

DATA LOGGING



USER INTERFACE

BENEFITS & SAVINGS
Savings calculated using $4.00/MCF

Patton Burner Management System placed on	CO2 Equiv. Emissions Reduction-TPY	Fuel Gas Savings $/Unit/Year
Secondary Burner Incineration	6,071	$ 52,560
Glycol Reboiler-Small Unit (100 MBTU/HR)	2,361	$ 20,440
Glycol Reboiler-Large Unit (2.5 MMBTU/HR)	27,993	$ 242,360

BURNER MANAGEMENT SOLUTIONS

CUSTOMIZED REPORTING

Patton
BURNER MANAGEMENT SYSTEM

The Patton Burner Management System (PBMS) is a unique combination of Flame Ignition, Data Acquisition, and Control.

Ignition

The **PBMS** is designed for users to easily set parameters for ignition sequence. The number of ignition retries, delay to sense flame, time for ignition delay to open the fuel valve, and flame sense intensity are all configurable from the easy to use menu on the controller screens.

POD - Pilot on Demand allows the pilot to remain off until it is needed based on pre-set temperature or pressure settings allowing you to save money and fuel gas.

Power

The standard unit is powered by 12 Volts DC, making solar charging an easy option for remote, or non powered applications. Other power combinations are also readily available.

Designed for use in Class 1, Division 2, Groups A,B,C, and D locations.

Control

With on board inputs and outputs, the PBMS can be easily configured for a variety of control sequences and shutdowns. Examples of alarm conditions would be high stack or reboiler temperature, reboiler and flash tank levels, and remote input shutdowns (based on external conditions; example-compressor shutdown). Control examples would be automated valve or drive control to maintain temperature.

Patton
BURNER MANAGEMENT SYSTEM

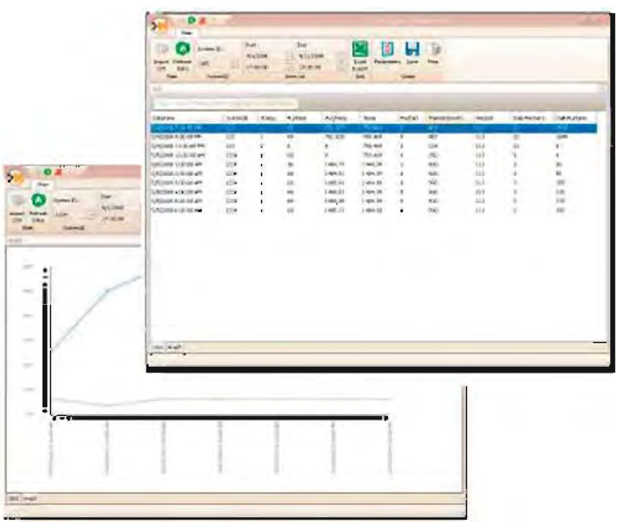
Logging

The PBMS has multiple ways of logging data. One is the ability of an on board storage chip that can easily be removed. Data can be collected to the chip and generated into user defined reports. With 1 to 4 Gigabytes of storage memory for logging various data points, air quality standards (like DEQ Title 5 which require 15 minute updates) are easily handled. With the extracted data PBMS can provide customized reports to meet customers needs.

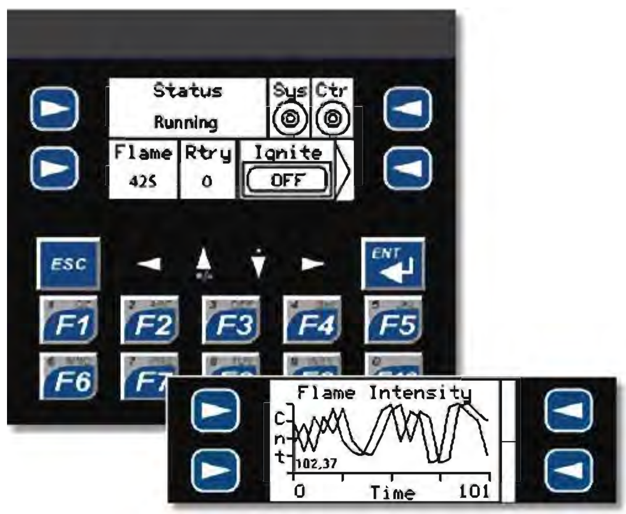
Another method of logging is through the retrieval of data via communications ports. The PBMS has built in Modbus communications, so data may also be retrieved and logged to existing SCADA Systems via radio, phone line or modem.

Overview

With a local user interface for configuration and tuning, on board logging, and built in Modbus communications, the PBMS system is the right choice for flame ignition control.



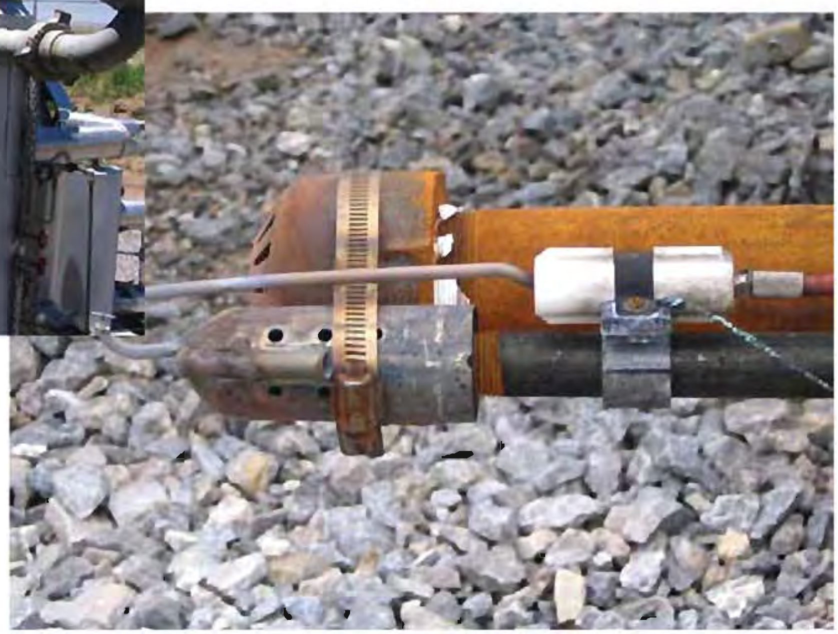
Collect and view data from your computer.



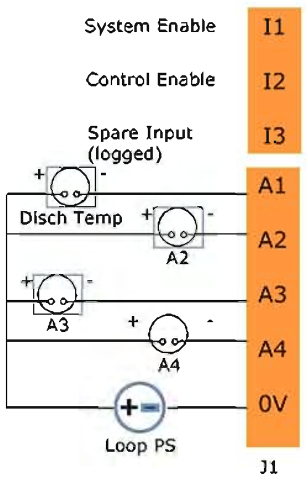
View status information on-site.

Representative Equipment: The burner system management vendor has not yet been selected.

Patton
BURNER MANAGEMENT SYSTEM

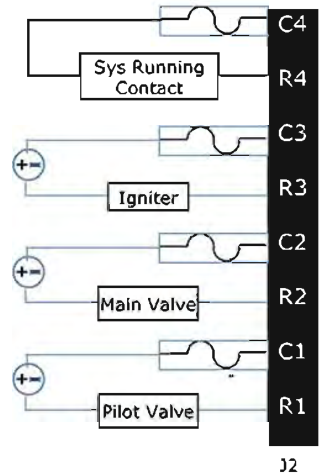


Patton
BURNER MANAGEMENT SYSTEM



System Enable
System On/Off switch. When switched on, the Ignite button must be pressed to start.

Control Enable
Similar to "System Enable" but the Ignite Button does not need to be pressed. Burner will try to ignite immediately. Flame detect on startup will still require operator intervention.



Sys Running (Main Valve Open)
Relay Contact indicating the system is running.

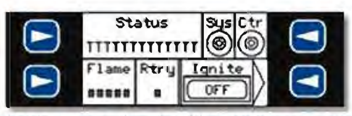
Rating: 3A at 250VAC Resistive, Max Voltage 275VAC/30VDC

Modbus Communications

A variety of Modbus Communication options are now available.

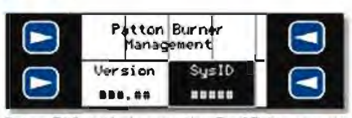
Quick Start / Setup

1



Start system, this should be the first screen you see.

2

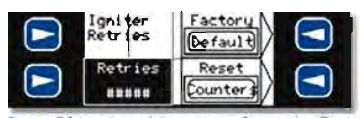


Press F10 and change the SysID to an unique number.

3

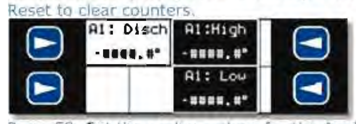
Press F10, again and change the clock.

4



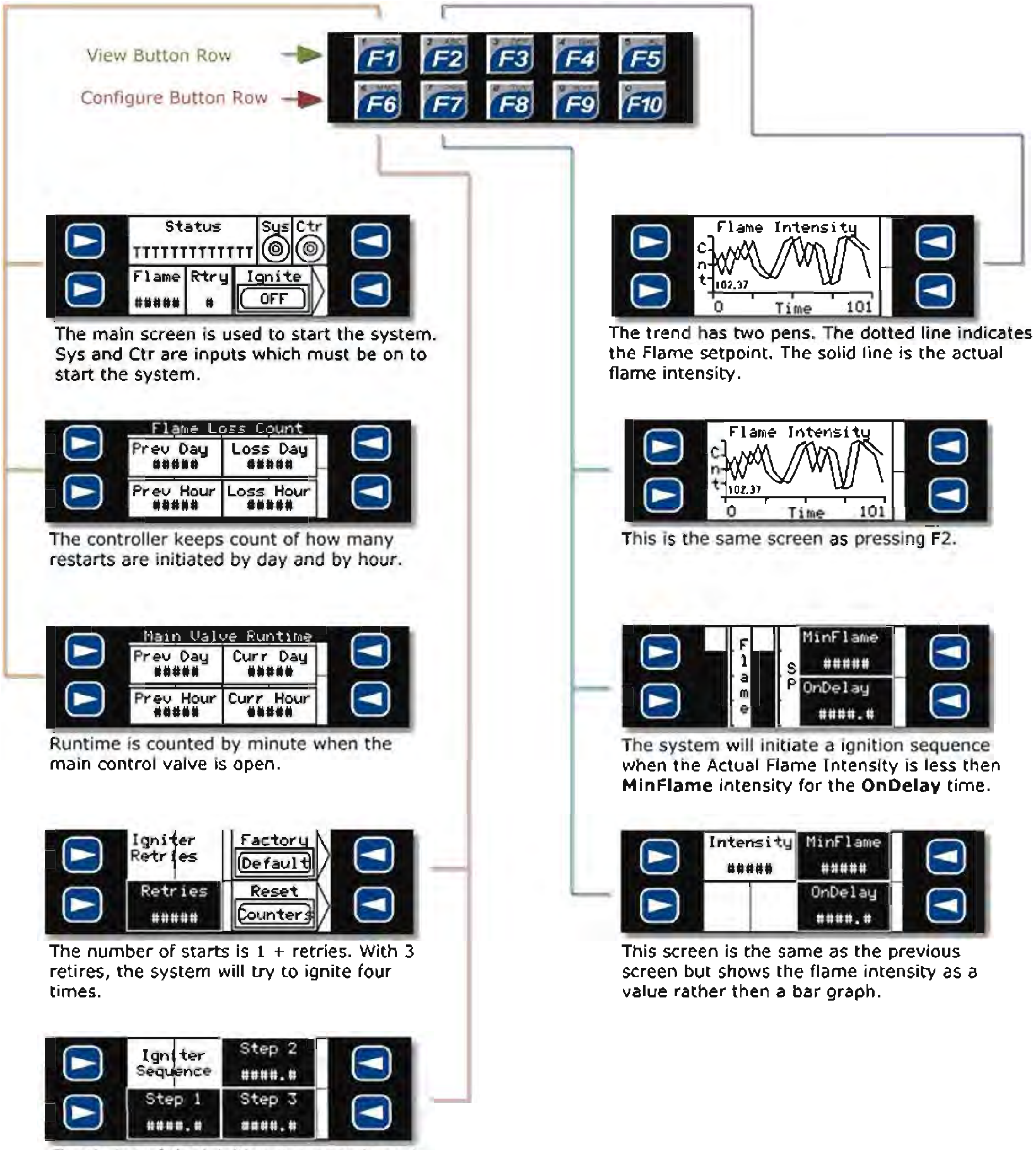
Press F6 to view this screen. Press the Factory Default Button (You will see 3 retires). Press Reset to clear counters.

5



Press F8. Set the scaling values for the Analog inputs if used.

Patton
BURNER MANAGEMENT SYSTEM



The main screen is used to start the system. Sys and Ctr are inputs which must be on to start the system.

The controller keeps count of how many restarts are initiated by day and by hour.

Runtime is counted by minute when the main control valve is open.

The number of starts is 1 + retries. With 3 retires, the system will try to ignite four times.

The timing of the iginition sequence is controlled through this screen. Step 1 is normally 7 seconds.

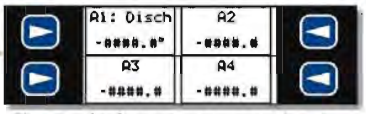
The trend has two pens. The dotted line indicates the Flame setpoint. The solid line is the actual flame intensity.

This is the same screen as pressing F2.

The system will initiate a ignition sequence when the Actual Flame Intensity is less then **MinFlame** intensity for the **OnDelay** time.

This screen is the same as the previous screen but shows the flame intensity as a value rather then a bar graph.

Patton
BURNER MANAGEMENT SYSTEM



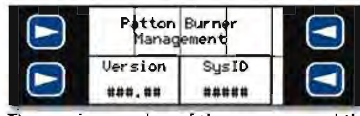
The standard system can support up to four analog inputs. A1 is normally used for discharge temperature.

Enter the High Range value (at 20mA)
Enter the Low Range value (at 4ma)

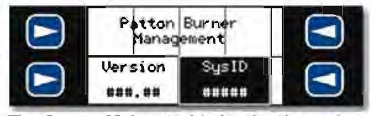
Enter the High Range value (at 20mA)
Enter the Low Range value (at 4ma)

Enter the High Range value (at 20mA)
Enter the Low Range value (at 4ma)

Enter the High Range value (at 20mA)
Enter the Low Range value (at 4ma)

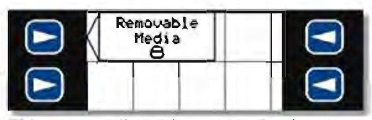


The version number of the program and the System ID are displayed by pressing F5.



The SystemID is settable by the the end user. The SystemID is included in all log entries.

To view the time, press the **Get** Button. If you make changes to the time or date, press the **Set** button to send to the controller.

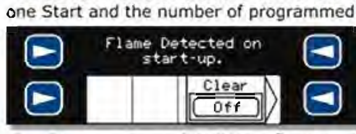


This screen allows the user to load new programs and file functions for the memory card.

Fault Screens

If either of these two screen show up, an operator will be required to clear the fault. Turning the System off will also clear the screens.

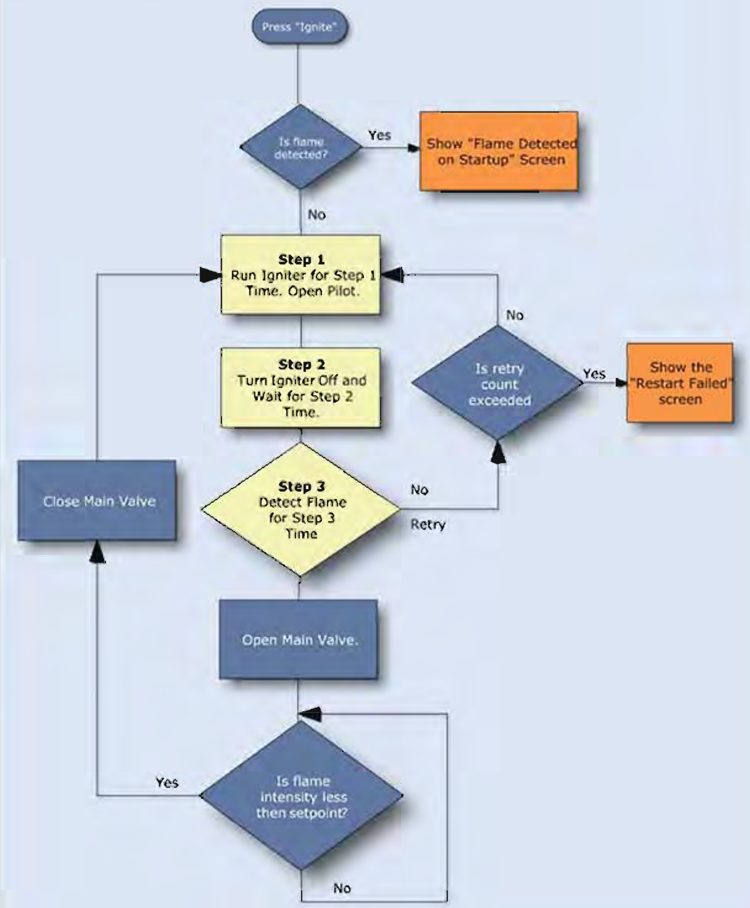
This screen indicates that the burner did not ignite after one Start and the number of programmed retries.



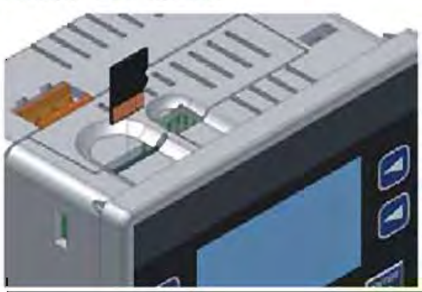
The Flame sensor is detecting a flame so the system will not start.

BURNER MANAGEMENT SYSTEM

Ignition Sequence Flow Chart

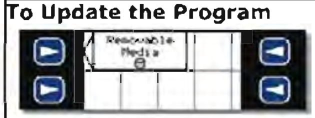


Micro SD Card



Micro SD Card
If a Micro SD card is inserted into the controller, the controller will start logging hourly data to the card. A 2GB card can handle years worth of data.

To Update the Program

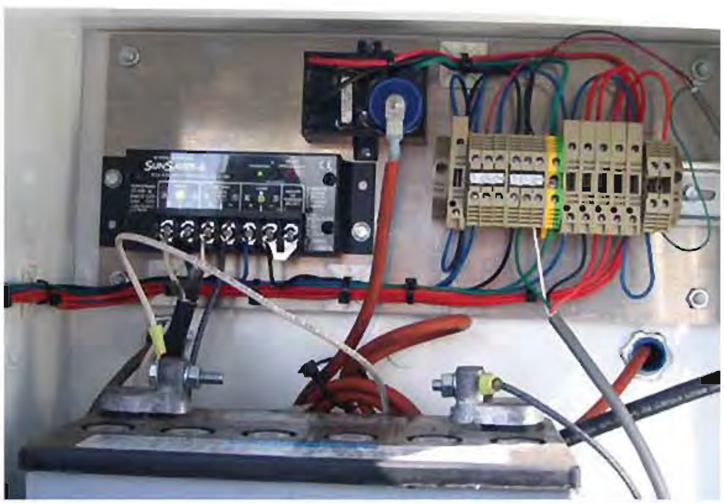


1. Copy the program to a Micro SD Card and insert into the controller.
2. Press F10 until you see the removable media button. Press the button.
3. Select the program using the small arrow keys and press enter.
4. The screen will show " Are you sure?", press the enter key.
5. The screen will show "Place in Run Mode?", press the enter key.

Representative Equipment: The burner system management vendor has not yet been selected.

Patton

BURNER MANAGEMENT SYSTEM



Patton

BURNER MANAGEMENT SYSTEM

Date	Time	Address	Event	Runtime Previous Hour	Temp Avg. Prev. Hr	Temp Real-time	Hourly flame count loss	Intensity	Version No.	Current Daily Flame Loss	Daily Runtime in Minutes
80504	170000	0	1	42	724.432	745.641	41	545	113	106	53
80504	180000	0	1	59	745.622	745.641	0	461	113	106	113
80504	190000	0	1	59	745.628	745.641	2	500	113	108	173
80504	200000	0	1	59	745.627	745.641	0	500	113	108	233
80504	210000	0	1	59	745.626	745.641	0	500	113	108	293
80504	220000	0	1	59	745.647	745.641	0	500	113	108	353
80504	230000	0	1	59	745.669	745.641	0	500	113	108	0
80505	0	0	1	59	745.672	745.641	0	500	113	0	60
80505	10000	0	1	59	745.674	745.641	0	500	113	0	120
80505	20000	0	1	59	745.674	745.641	0	600	113	0	180
80505	30000	0	1	59	745.66	745.641	0	500	113	0	240
80505	40000	0	1	59	745.649	745.641	0	500	113	0	300
80505	50000	0	1	59	745.631	745.641	0	500	113	0	360
80505	60000	0	1	59	745.597	745.641	0	500	113	0	420
80505	70000	0	1	59	745.613	745.641	0	600	113	0	480
80505	80000	0	1	59	745.59	745.641	0	500	113	0	540
80505	90000	0	1	59	745.61	745.641	1	500	114	1	599
80505	100000	0	1	60	745.622	748.641	0	500	114	1	659
80505	110000	0	1	60	745.637	745.641	0	500	114	1	719
80505	120000	0	1	22	745.572	745.641	4	500	114	5	741
80505	130000	0	9	34	745.563	745.641	1	333	114	6	775
80505	140000	49	5	22	745.571	745.641	1	0	117	1	22

Representative Equipment: The burner system management vendor has not yet been selected.

Patton

BURNER MANAGEMENT SYSTEM

CAM

CONTROL DEVICE: THERMAL INCINERATOR (DIRECT FLAME INCINERATOR/REGENERATIVE THERMAL OXIDIZER/THERMAL OXIDIZER)

INDICATOR MONITORED	MONITORING SPECIFICATIONS AND PROCEDURES	MIN FREQ.	AVERAGE
CAMG-OG-TI-001 Combustion Temperature/ Exhaust Gas Temperature	The monitoring device should be installed in the combustion chamber or immediately downstream of the combustion chamber. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, other written procedures that provide an adequate assurance that the device is calibrated accurately, or at least annually, whichever is more frequent, and shall be accurate to within one of the following: C + 0.75% of the temperature being measured expressed in degrees Celsius;or 2% of reading; or C + 2.5 degrees Celsius. Deviation Limit: A minimum combustion temperature shall be established using the most appropriate of the following: the most recent performance test data, the manufacturer's recommendations, engineering calculations, and/or historical data.	once per day	n/a

CONTROL DEVICE: STEAM GENERATING UNIT (BOILER, PROCESS HEATER) USED AS VOC CONTROL

INDICATOR MONITORED	MONITORING SPECIFICATIONS AND PROCEDURES	MIN FREQ.	AVERAGE
CAMG-OG-SG-001 Combustion Temperature/ Exhaust Gas Temperature	The monitoring device should be installed in the combustion chamber or immediately downstream of the combustion chamber into which the volatile organic compound is introduced. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, other written procedures that provide an adequate assurance that the device is calibrated accurately, or at least annually, whichever is more frequent, and shall be accurate to within one of the following: C + 2% of the reading; or C + 2.5 degrees Celsius. Deviation Limit: A minimum combustion temperature shall be established using the most appropriate of the following: the most recent performance test data, the manufacturer's recommendations, engineering calculations, and/or historical data.	once per day	n/a

CONTROL DEVICE: FLARE

INDICATOR MONITORED	MONITORING SPECIFICATIONS AND PROCEDURES	MIN FREQ.	AVERAGE
CAMG-OG-FL-001 Combustion Temperature/ Exhaust Gas Temperature	Monitor the presence of a flare pilot flame using a thermocouple or other equivalent device to detect the presence of a flame or using an alarm that uses a thermocouple or other equivalent device to detect the absence of a flame. Maintain records of alarm events and duration of alarm events. Each monitoring device shall be accurate to within manufacturer's recommendations. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications or other written procedures that provide an adequate assurance that the device is calibrated accurately. Deviation Limit: No pilot flame.	continuous	n/a

PM

UNITS WITH A CONTROL DEVICE: THERMAL INCINERATOR (DIRECT FLAME INCINERATOR/REGENERATIVE THERMAL OXIDIZER)

INDICATOR MONITORED	MONITORING SPECIFICATIONS AND PROCEDURES	MIN FREQ.	AVERAGE
PMG-OG-V-007 Combustion Temperature/ Exhaust Gas Temperature	Measure and record the combustion temperature in the combustion chamber or immediately downstream of the combustion chamber. Establish a minimum combustion temperature using the most recent performance test , manufacturer's recommendations, engineering calculations, and/or historical data. The monitoring instrumentation shall be maintained, calibrated, and operated in accordance with the manufacturer's specifications or other written procedures. Any monitoring data below the minimum limit shall be considered and reported as a deviation.	once per week	n/a

Patton
BURNER MANAGEMENT SYSTEM

The Patton Compact Burner Management System (PCBMS) is engineered for intelligent control of Flame Ignition.

Ignition

The PCBMS is designed for users to set parameters relating to ignition sequence. Users can setup ignition retries, delay to sense flame, ignition delay time to open fuel valve, and flame intensity with easily configurable menu screens.

Power

The standard unit is powered by 12 Volts DC, making solar charging an easy option for remote or non-powered applications. Other power combinations are also readily available.

Control

The PCBMS provides precise flame ignition sequencing. The timing, such as starter on time and retry delay, can be configured from the panel.

Patton
BURNER MANAGEMENT SYSTEM

Retries

The PCBMS can be configured for the desired number of retries. If the burner fails to ignite after the configured number of retries, the panel will go into fault mode.

Restarts

The PCBMS can be programmed to do restarts after a specified amount of time, such as every 15 minutes. Both the time delay and the number of restart tries can be configured through the built in display.

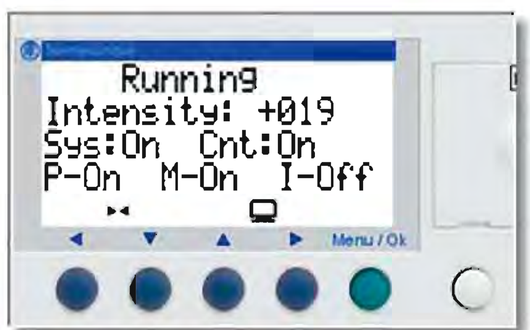
Control Input

The panel can accept an external control input that can be used to turn the burner on or off. Examples of this input type could be a temperature or pressure switch.

Display

The controller has a built-in display showing system status and flame intensity.

Control input allows for a wide varitey of external control solutions.



View status information on-site.

APPENDIX D
BACT SUPPORTING DOCUMENTATION

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

RBLC DOWNLOAD - CARBON DIOXIDE - ALL SOURCES
AIR PERMIT APPLICATION
JACKSON COUNTY GAS PLANT
ETC TEXAS PIPELINE, LTD.

RBLCID	FACILITY NAME	COMPANY NAME	FACILITY COUNTY	FACILITY STATE	PERMIT NUMBER	SIC CODE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 2	EMISSION LIMIT 2 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	POLLUTANT COMPLIANCE NOTES
TX-0550	BASF FINA NAFTA REGION OLEFINS COMPLEX	BASF FINA PETROCHEMICALS LIMITED PARTNERSHIP	JEFFERSON	TX	36644	2869	2/10/2010	N-11, REACTOR REGENERATION EFFLUENT	METHANE	5,064.83	CFS								NO EMISSION LIMITS AVAILABLE
								N-18, DECOKING DRUM	METHANE	26,625	LB COKE/CYCLE								NO EMISSION LIMITS AVAILABLE
								N-10, CATALYST REGENERATION EFFLUENT	METHANE	2,100	CFS								NO EMISSION LIMITS AVAILABLE
OK-0135	PRYOR PLANT CHEMICAL	PRYOR PLANT CHEMICAL COMPANY	MAYES	OK	2008-100-C PSD	2873	2/23/2009	CARBON DIOXIDE VENT		36.5	T/H	GOOD OPERATION PRACTICES	3.65	LB/H					
TX-0481	AIR PRODUCTS BAYTOWN I I	AIR PRODUCTS LP	HARRIS	TX	PSD-TX-1044 / 35873	492	11/2/2004	EMERGENCY GENERATOR					2.24	LB/H	0.99	T/YR			
TX-0347	CHOCOLATE BAYOU PLANT	BP AMOCO CHEMICAL COMPANY	BRAZORIA	TX	PSD-TX-854	2869	10/16/2001	REGENERATION HEATER, DDB-201				NONE INDICATED	2.1	LB/H	9.3	T/YR			
								DECOKE STACK, DDF-101				NONE INDICATED	36.5	LB/H	7.2	T/YR			

RBLC DOWNLOAD - METHANE - ALL SOURCES
AIR PERMIT APPLICATION
JACKSON COUNTY GAS PLANT
ETC TEXAS PIPELINE, LTD.

RBLCID	FACILITY NAME	COMPANY NAME	FACILITY COUNTY	FACILITY STATE	PERMIT NUMBER	SIC CODE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 2	EMISSION LIMIT 2 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	POLLUTANT COMPLIANCE NOTES
OH-0330	RUMPKE SANITARY LANDFILL	RUMPKE SANITARY LANDFILL	BROWN	OH	07-00574	4953	12/23/2008	ENCLOSED COMBUSTORS (4)	LANDFILL GAS			COMBUSTORS ARE THE CONTROL	299.01	LB/H	1309.66	T/YR			CALCULATED FROM EMISSION FACTORS FROM USEPA'S LANDFILL GAS EMISSIONS MODEL AND AP-42 SECTION 2.4
OH-0330	RUMPKE SANITARY LANDFILL	RUMPKE SANITARY LANDFILL	BROWN	OH	07-00574	4953	12/23/2008	CANDLESTICK FLARE (5)	LANDFILL GAS			FLARE IS CONTROL	25	LB/H	109.45	T/YR			
OH-0330	RUMPKE SANITARY LANDFILL	RUMPKE SANITARY LANDFILL	BROWN	OH	07-00574	4953	12/23/2008	OPEN FLARE	LANDFILL GAS			FLARE IS CONTROL	25	LB/H	109.45	T/YR			
MD-0040	CPV ST CHARLES	COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC	CHARLES	MD	CPCN CASE NO. 9129	1731	11/12/2008	INTERNAL COMBUSTION ENGINE - EMERGENCY FIRE WATER PUMP	DIESEL	300	HP		3	G/HP-H					COMBINED LIMIT OF NOX AND NON-METHANE HYDROCARBON

GOOD COMBUSTION PRACTICES

This guidance is intended to be used by the source work groups in their evaluation of alternative concepts regarding good combustion practices. While operator training could also be considered a good combustion practice, it is covered by separate guidance.

Examples of practices listed are intended to indicate the range of existing practices which are dependent on the specific type of equipment utilized and the fuel/waste input to the combustion device. All examples of specific techniques are not considered applicable to all combustion sources. The source work groups should be requested to evaluate techniques, practices, and possible standard approaches appropriate for subcategories or other subsets of sources.

Periodic checks and adjustments of combustion equipment are intended to occur at intervals appropriate for the source, with key combustion checks timed no less frequent than to coincide with overhaul frequencies.

Good Combustion Technique	Examples of Practices	Applicable Source Types	Possible Standard
Operator practices	-Official documented operating procedures, updated as required for equipment or practice change -Procedures include startup, shutdown, malfunction -Operating logs/record keeping	All	-Maintain written site specific operating procedures in accordance with GCPs, including startup, shutdown, malfunction
Maintenance knowledge	-Training on applicable equipment & procedures	All	-Equipment maintained by personnel with training specific to equipment
Maintenance practices	-Official documented maintenance procedures, updated as required for equipment or practice change -Routinely scheduled evaluation, inspection, overhaul as appropriate for equipment involved -Maintenance logs/record keeping	All	-Maintain site specific procedures for best/optimum maintenance practices -Scheduled periodic evaluation, inspection, overhaul as appropriate

Good Combustion Technique	Examples of Practices	Applicable Source Types	Possible Standard
Stoichiometric (fuel/air) ratio	-Burner & control adjustment based on visual checks -Burner & control adjustment based on continuous or periodic monitoring (O_2, CO, CO_2) -Fuel/air metering, ratio control -Oxygen trim control -CO control -Safety interlocks	Open combustion	-SR limits appropriate for unit design & fuel -Routine & periodic adjustment -CO limit
Firebox (furnace) residence time, temperature, turbulence	-Supplemental stream injection into active flame zone -Residence time by design (incinerators) -Minimum combustion chamber temperature (incinerators)	-Open combustion with supplemental vent streams -Incinerators	
Proper liquid atomization	-Differential pressure between atomizing media & liquid -Flow ratio of atomizing media to liquid flow -Liquid temp or viscosity -Flame appearance -Atomizer condition -Atomizing media quality	Open combustion with liquid fuel/waste	-Routine & periodic adjustments & checks -Maintain procedures to ensure adequate atomization & mixing with combustion air
Fuel/waste quality (analysis); fuel/waste handling	-Monitor fuel/waste quality -Fuel quality certification from supplier if needed -Periodic fuel/waste sampling and analysis -Fuel/waste handling practices	All- where appropriate	-Fuel/waste analysis where composition could vary & of significance to HAP emissions (e.g., not pipeline natural gas) -Fuel/waste handling procedures applicable to the fuel/waste
Fuel/waste sizing	-Fuel/waste sizing specification & checks -Pulverized coal fineness checks	Solid fuel/waste firing	-Specification appropriate for fuel/waste fired -Periodic checks
Combustion air distribution	-Adjustment of air distribution system based on visual observations -Adjustment of air distribution based on continuous or periodic monitoring	Mainly stoker and solid fuel firing	-Routine & periodic adjustments & checks
Fuel/waste dispersion	-Adjustment based on visual observations	Solid fuel/waste firing	-Routine & periodic adjustments & checks

POTENTIAL TO EMIT FOR ENGINES REQUIRED FOR CCS

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.

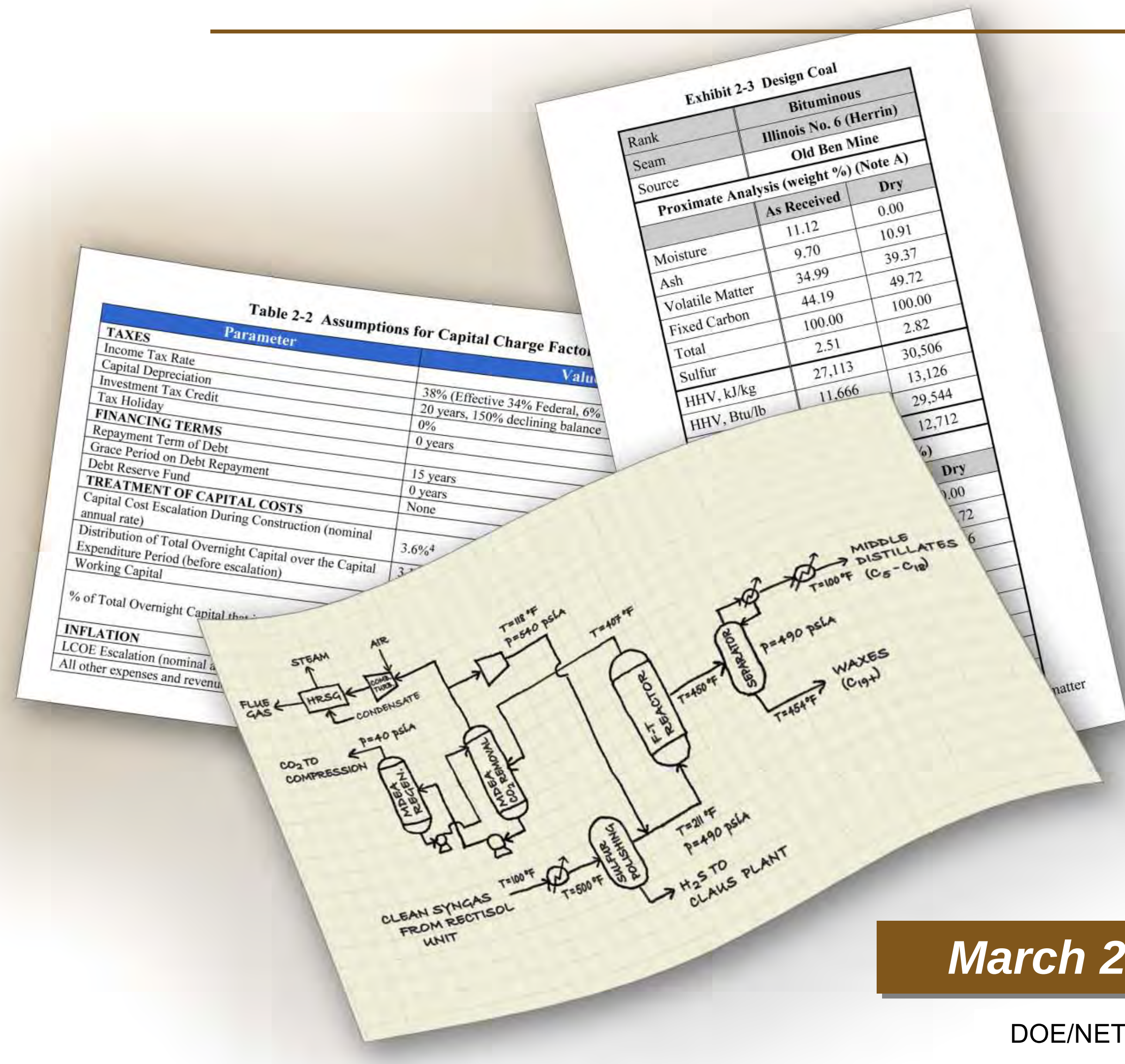
Description	Type	Engine Ratings: Rated Horsepower (hp)	Engine Ratings: Fuel Consumption (Btu/hp-hr)	Number of Engines	Annual Operating Hours (hr/yr)	Pollutant	Emission Factors [a]	Units	Total Potential to Emit (PTE): Hourly (lb/hr)	Total Potential to Emit (PTE): Annual (T/yr)
CO_2 Compressors	Caterpillar G 3606	1,775	7,555	1	8,760	CO	0.16	g/hp-hr	0.62	2.74
	4 stroke, lean burn					NO_X	0.07	g/hp-hr	0.27	1.20
	oxidation catalyst					PM	0.0099871	lb/MMBtu	0.13	0.59
						SO_2	4	ppmv	0.01	0.04
						VOC	0.26	g/hp-hr	1.02	4.45
						CH_2O	0.03	g/hp-hr	0.12	0.50
						CO_2	53.02	kg/MMBtu	1,567.48	6,865.57
Inlet Compressors	Caterpillar G 3616	4,734	7,423	8	8,760	CO	0.16	g/hp-hr	3.17	13.87
	4 stroke, lean burn					NO_X	0.07	g/hp-hr	1.39	6.08
	oxidation catalyst					PM	0.0099871	lb/MMBtu	2.81	12.30
						SO_2	4	ppmv	0.03	0.11
						VOC	0.26	g/hp-hr	5.15	22.54
						CH_2O	0.03	g/hp-hr	0.58	2.56
						CO_2	53.02	kg/MMBtu	32,859.97	143,926.69
Propane Compressors	Caterpillar G 3516	1,500	7,423	6	8,760	CO	0.16	g/hp-hr	3.17	13.87
	4 stroke, lean burn					NO_X	0.07	g/hp-hr	1.39	6.08
	oxidation catalyst					PM	0.0099871	lb/MMBtu	0.67	2.92
						SO_2	4	ppmv	0.01	0.04
						VOC	0.26	g/hp-hr	5.15	22.54
						CH_2O	0.03	g/hp-hr	0.58	2.56
						CO_2	53.02	kg/MMBtu	7,808.93	34,203.11
TOTAL EMISSIONS								**CO**	**6.96**	**30.48**
								NO_X	**3.05**	**13.37**
								PM	**3.61**	**15.81**
								SO_2	**0.04**	**0.19**
								VOC	**11.31**	**49.53**
								CH_2O	**1.28**	**5.61**
								CO_2	**42,236.39**	**184,995.37**

NETL

the ENERGY lab

QUALITY GUIDELINES FOR ENERGY SYSTEM STUDIES

Estimating Carbon Dioxide Transport and Storage Costs



March 2010

DOE/NETL-2010/1447

NATIONAL ENERGY TECHNOLOGY LABORATORY

U.S. DEPARTMENT OF ENERGY

Quality Guidelines for Energy Systems Studies

Estimating CO_2 Transport, Storage & Monitoring Costs

Background

This paper explores the costs associated with geologic sequestration of carbon dioxide (CO_2). This cost is often cited at the flat figure of $5-10 per short ton of CO_2 removed, but estimates can vary with values as high as $23 per short ton having been published recently [1, 2, 3]. The variability of these costs is due in part to the wide range of transportation and storage options available for CO_2 sequestration, but may also relate to the dramatic rise of construction and material costs in the United States which has occurred over the last several years. This paper examines the transportation of CO_2 via pipeline to, and storage of that CO_2 in, a geologic formation representative of those identified in North America as having storage potential based on data available from the literature.

Approach

Geologic sequestration costs were assessed based on the pipeline transport and injection of super-critical CO_2 into a geologic reservoir representative of those identified in North America as having storage potential. High pressure (2,200 psig) CO_2 is provided by the power plant or energy conversion facility and the cost and energy requirements of compression are assumed by that entity. CO_2 is in a super-critical state at this pressure which is desirable for transportation and storage purposes.

CO_2 exits the pipeline terminus at a pressure of 1,200 psig, and the pipeline diameter was sized for this to be achieved without the need for recompression stages along the pipeline length. This exit pressure specification: (1) ensures that CO_2 remains in a supercritical state throughout the length of the pipeline regardless of potential pressure drops due to pipeline elevation change[1]; (2) is equivalent to the reservoir pressure – exceeding it after hydrostatic head is accounted for – alleviating the need for recompression at the storage site; and (3) minimizes the pipeline diameter required, and in turn, transport capital cost.

The required pipeline diameter was calculated iteratively by determining the diameter required to achieve a 1,000 psig pressure drop (2,200 psig inlet, 1,200 psig outlet) over the specified pipeline distance, and rounding up to the nearest even sized pipe diameter. The pipeline was sized based on the CO_2 output produced by the power plant when it is operating at full capacity (100% utilization factor) rather than the average capacity.

The storage site evaluated is a saline formation at a depth of 4,055 feet (1,236 meters) with a permeability of 22 md and down-hole pressure of 1,220 psig (8.4 MPa) [4].[2] This is considered an average storage site and requires roughly one injection well for each 10,300 short tons of CO_2 injected per day [4]. An overview of the geologic formation characteristics are shown in Table 1.

Table 1: Deep, Saline Formation Specification [4]

Parameter	Units	Average Case
Pressure	MPa (psi)	8.4 (1,220)
Thickness	m (ft)	161 (530)
Depth	m (ft)	1,236 (4,055)
Permeability	Md	22
Pipeline Distance	km (miles)	80 (50)
Injection Rate per Well	tonne (short ton) CO_2/day	9,360 (10,320)

[1] Changes in pipeline elevation can result in pipeline pressure reductions due to head losses, temperature variations or other factors. Therefore a 10% safety margin is maintained to ensure the CO_2 supercritical pressure of 1,070 psig is exceeded at all times.
[2] "md", or millidarcy, is a measure of permeability defined as 10^{-12} Darcy.

Cost Sources & Methodology

The cost metrics utilized in this study provide a best estimate of T, S, & M costs for a "typical" sequestration project, and may vary significantly based on variables such as terrain to be crossed by the pipeline, reservoir characteristics, and number of land owners from which sub-surface rights must be acquired. Raw capital and operating costs are derived from detailed cost metrics found in the literature, escalated to June 2007-year dollars using appropriate price indices. These costs were then verified against values quoted by any industrial sources available. Where regulatory uncertainty exists or costs are undefined, such as liability costs and the acquisition of underground pore volume, analogous existing policies were used for representative cost scenarios.

The following sections describe the sources and methodology used for each metric.

Cost Levelization and Sensitivity Cases

Capital costs were levelized over a 30-year period and include both process and project contingency factors. Operating costs were similarly levelized over a 30-year period and a sensitivity analysis was performed to determine the effects of different pipeline lengths on overall and avoided costs as well as the distribution of transport versus storage costs.

In several areas, such as Pore Volume Acquisition, Monitoring, and Liability, cost outlays occur over a longer time period, up to 100 years. In these cases a capital fund is established based on the net present value of the cost outlay, and this fund is then levelized as described in the previous paragraph.

Following the determination of cost metrics, a range of CO_2 sequestration rates and transport distances were assessed to determine cost sensitivity to these parameters. Costs were also assessed in terms of both removed and avoided emissions cost, which requires power plant specific information such as plant efficiency, capacity factor, and emission rates. This paper presents avoided and removed emission costs for both Pulverized Coal (PC) and Integrated Gasification Combined Cycle (IGCC) cases using data from Cases 11 & 12 (Supercritical PC with and without CO_2 Capture) and Cases 1 & 2 (GEE Gasifier with and without CO_2 Capture) from the *Bituminous Baseline Study* [5].

Transport Costs

CO_2 transport costs are broken down into three categories: pipeline costs, related capital expenditures, and O&M costs.

Pipeline costs are derived from data published in the Oil and Gas Journal's (O&GJ) annual Pipeline Economics Report for existing natural gas, oil, and petroleum pipeline project costs from 1991 to 2003. These costs are expected to be analogous to the cost of building a CO_2 pipeline, as noted in various studies [4, 6, 7]. The University of California performed a regression analysis to generate the following cost curves from the O&GJ data: (1) Pipeline Materials, (2) Direct Labor, (3) Indirect Costs[3], and (4) Right-of-way acquisition, with each represented as a function of pipeline length and diameter [7].

Related capital expenditures were based on the findings of a previous study funded by DOE/NETL, *Carbon Dioxide Sequestration in Saline Formations – Engineering and Economic Assessment* [6]. This study utilized a similar basis for pipeline costs (Oil and Gas Journal Pipeline cost data up to the year 2000) but added a CO_2 surge tank and pipeline control system to the project.

Transport O&M costs were assessed using metrics published in a second DOE/NETL sponsored report entitled *Economic Evaluation of CO_2 Storage and Sink Enhancement Options* [4]. This study was chosen due to the reporting of O&M costs in terms of pipeline length, whereas the other studies mentioned above either (a)

[3] Indirect costs are inclusive of surveying, engineering, supervision, contingencies, allowances for funds used during construction, administration and overheads, and regulatory filing fees.

do not report operating costs, or (b) report them in absolute terms for one pipeline, as opposed to as a length- or diameter-based metric.

Storage Costs

Storage costs were broken down into five categories: (1) Site Screening and Evaluation, (2) Injection Wells, (3) Injection Equipment, (4) O&M Costs, and (5) Pore Volume Acquisition. With the exception of Pore Volume Acquisition, all of the costs were obtained from *Economic Evaluation of CO_2 Storage and Sink Enhancement Options* [4]. These costs include all of the costs associated with determining, developing, and maintaining a CO_2 storage location, including site evaluation, well drilling, and the capital equipment required for distributing and injecting CO_2.

Pore Volume Acquisition costs are the costs associated with acquiring rights to use the sub-surface area where the CO_2 will be stored, i.e. the pore space in the geologic formation. These costs were based on recent research by Carnegie Mellon University which examined existing sub-surface rights acquisition as it pertains to natural gas storage [8]. The regulatory uncertainty in this area combined with unknowns regarding the number and type (private or government) of property owners requires a number of “best engineering judgment” decisions to be made, as documented below under Cost Metrics.

Liability Protection

Liability Protection addresses the fact that if damages are caused by injection and long-term storage of CO_2, the injecting party may bear financial liability. Several types of liability protection schemas have been suggested for CO_2 storage, including Bonding, Insurance, and Federal Compensation Systems combined with either tort law (as with the Trans-Alaska Pipeline Fund), or with damage caps and preemption, as is used for nuclear energy under the Price Anderson Act [9].

At present, a specific liability regime has yet to be dictated either at a Federal or (to our knowledge) State level. However, certain state governments have enacted legislation which assigns liability to the injecting party, either in perpetuity (Wyoming) or until ten years after the cessation of injection operations, pending reservoir integrity certification, at which time liability is turned over to the state (North Dakota and Louisiana) [10, 11, 12]. In the case of Louisiana, a trust fund of five million dollars is established for each injector over the first ten years (120 months) of injection operations. This fund is then used by the state for CO_2 monitoring and, in the event of an at-fault incident, damage payments.

This study assumes that a bond must be purchased before injection operations are permitted in order to establish the ability and good will of an injector to address damages where they are deemed liable. A figure of five million dollars was used for the bond based on the Louisiana fund level. This Bond level may be conservative, in that the Louisiana fund covers both liability and monitoring, but that fund also pertains to a certified reservoir where injection operations have ceased, having a reduced risk compared to active operations. This cost may be updated as more specific liability regimes are instituted at the Federal or State levels. The Bond cost was not escalated.

Monitoring Costs

Monitoring costs were evaluated based on the methodology set forth in the IEA Greenhouse Gas R&D Programme’s *Overview of Monitoring Projects for Geologic Storage Projects* report [13]. In this scenario, operational monitoring of the CO_2 plume occurs over thirty years (during plant operation) and closure monitoring occurs for the following fifty years (for a total of eighty years). Monitoring is via electromagnetic (EM) survey, gravity survey, and periodic seismic survey, EM and gravity surveys are ongoing while seismic survey occurs in years 1, 2, 5, 10, 15, 20, 25, and 30 during the operational period, then in years 40, 50, 60, 70, and 80 after injection ceases.

Cost Metrics

The following sections detail the Transport, Storage, Monitoring, and Liability cost metrics used to determine CO_2 sequestration costs for the deep, saline formation described above. The cost escalation indices utilized to bring these metrics to June-2007 year dollars are also described below.

Transport Costs

The regression analysis performed by the University of California breaks down pipeline costs into four categories: (1) Materials, (2) Labor, (3) Miscellaneous, and (4) Right of Way. The Miscellaneous category is inclusive of costs such as surveying, engineering, supervision, contingencies, allowances, overhead, and filing fees [7]. These cost categories are reported individually as a function of pipeline diameter (in inches) and length (in miles) in Table 2 [7].

The escalated CO_2 surge tank and pipeline control system capital costs, as well as the Fixed O&M costs (as a function of pipeline length) are also listed in Table 2. Fixed O&M Costs are reported in terms of dollars per miles of pipeline per year.

Storage Costs

Storage costs were broken down into five categories: (1) Site Screening and Evaluation, (2) Injection Wells, (3) Injection Equipment, (4) O&M Costs, and (5) Pore Space Acquisition. Additionally, the cost of Liability Protection is also listed here for the sake of simplicity. Several storage costs are evaluated as flat fees, including Site Screening & Evaluation and the Liability Bond required for sequestration to take place.

As mentioned in the methodology section above, the site screening and evaluation figure of $4.7 million dollars is derived from *Economic Evaluation of CO_2 Storage and Sink Enhancement Options* [4]. Some sources in

Table 2: Pipeline Cost Breakdown [4, 6, 7]

Cost Type	Units	Cost
Pipeline Costs		
Materials	*$ Diameter (inches), Length (miles)*	$\$64,632 + \$1.85 \times L \times (330.5 \times D^2 + 686.7 \times D + 26,960)$
Labor	*$ Diameter (inches), Length (miles)*	$\$341,627 + \$1.85 \times L \times (343.2 \times D^2 + 2,074 \times D + 170,013)$
Miscellaneous	*$ Diameter (inches), Length (miles)*	$\$150,166 + \$1.58 \times L \times (8,417 \times D + 7,234)$
Right of Way	*$ Diameter (inches), Length (miles)*	$\$48,037 + \$1.20 \times L \times (577 \times D + 29,788)$
Other Capital		
CO_2 Surge Tank	$	$1,150,636
Pipeline Control System	$	$110,632
O&M		
Fixed O&M	$/mile/year	$8,632

industry, however, have quoted significantly higher costs for site screening and evaluation, on the magnitude of $100 to $120 million dollars. The higher cost may be reflective of a different criteria utilized in assessing costs, such as a different reservoir size – the reservoir assessed in the higher cost case could be large enough to serve 5 to 7 different injection projects – or uncertainty regarding the success rate in finding a suitable reservoir. Future analyses will examine the sensitivity of overall T, S, and M costs to higher site evaluation costs.

Pore Space Acquisition costs are based on acquiring long-term (100-year) lease rights and paying annual rent to land-owners once the CO_2 plume has reached their property. Rights are acquired by paying a one-time $500 fee to land-owners before injection begins, as per CMU's design criteria [8]. When the CO_2 plume enters into the area owned by that owner (as determined by annual monitoring), the injector begins paying an annual "rent" of $100 per acre to that owner for the period of up to 100 years from plant start-up [8]. A 3% annual escalation rate is assumed for rental rate over the 100-year rental period [8]. Similar to the CMU study, this study assumes that the plume area will cover rights need to be acquired from 120 landowners, however, a sensitivity analysis found that the overall acquisition costs were not significantly affected by this: increasing the

Table 3: Geologic Storage Costs [4, 8, 11]

Cost Type	Units	Cost
Capital		
Site Screening and Evaluation	$	$4,738,488
Injection Wells	\$/injection well (*see formula*)[1,2,3]	$\$240{,}714 \times e^{0.0008 \times well-depth}$
Injection Equipment	\$/injection well (*see formula*)[2]	$\$94{,}029 \times \left(\frac{7{,}389}{280 \times \#of\ injection\ wells}\right)^{0.5}$
Liability Bond	$	$5,000,000
Declining Capital Funds		
Pore Space Acquisition	\$/short ton CO_2	\$0.334/short ton CO_2
O&M		
Normal Daily Expenses (Fixed O&M)	\$/injection well	$11,566
Consumables (Variable O&M)	\$/yr/short ton CO_2/day	$2,995
Surface Maintenance (Fixed O&M)	*see formula*	$\$23{,}478 \times \left(\frac{7{,}389}{280 \times \#of\ injection\ wells}\right)^{0.5}$
Subsurface Maintenance (Fixed O&M)	\$/ft-depth/inject. well	$7.08

[1]The units for the "well depth" term in the formula are meters of depth.
[2]The formulas at right describe the cost per injection well and in each case the number of injection wells should be multiplied the formula in order to determine the overall capital cost.
[3]The injection well cost is $508,652 per injection well for the 1,236 meter deep geologic reservoir assessed here.

number of owners to 120,000 resulted in a 110% increase in costs and a 1% increase in the overall LCOE of the plant [8]. However, this assumption will be revisited in future work.

To ensure that Pore Space Acquisition costs are met after injection ceases, a sinking capital fund is set up to pay for these costs by determining the present value of the costs over the 100-year period (30 years of injection followed by 70 additional years), assuming a 10% discount rate. The size of this fund – as described in Table 3 – is determined by estimating the final size of the underground CO_2 plume, based on both the total amount of CO_2 injected over the plant lifetime and the reservoir characteristics described in Table 1. After injection, the CO_2 plume is assumed to grow by 1% per year [9].

The remaining capital costs are based on the number of injection wells required, which has been calculated to be one injection well for every 10,320 short tons of CO_2 injected per day. O&M costs are based on the number of injection wells, the CO_2 injection rates, and injection well depth.

Monitoring Costs

Monitoring costs were evaluated based on the methodology set forth in the IEA Greenhouse Gas R&D Programme's *Overview of Monitoring Projects for Geologic Storage Projects* report [13]. In this scenario, operational monitoring of the CO_2 plume occurs over thirty years (during plant operation) and closure monitoring occurs for the following fifty years (for a total of eighty years). Monitoring is via electromagnetic (EM) survey, gravity survey, and periodic seismic survey, EM and gravity surveys are ongoing while seismic survey occurs in years 1, 2, 5, 10, 15, 20, 25, and 30 during the operational period, then in years 40, 50, 60, 70, and 80 after injection ceases.

Operational and closure monitoring costs are assumed to be proportional to the plume size plus a fixed cost, with closure monitoring costs evaluated at half the value of the operational costs. The CO_2 plume is assumed to grow from 18 square kilometers (km^2) after the first year to 310 km^2 in after the 30^{th} (and final) year of injection. The plume grows by 1% per year thereafter, to a size of 510 km^2 after the 80^{th} year [9].The present value of the life-cycle costs is assessed at a 10% discount rate and a capital fund is set up to pay for these costs over the eighty year monitoring cycle. The present value of the capital fund is equivalent to $0.377 per short ton of CO_2 to be injected over the operational lifetime of the plant.

Cost Escalation

Four different cost escalation indices were utilized to escalate costs from the year-dollars they were originally reported in, to June 2007-year dollars. These are the Chemical Engineering Plant Cost Index (CEPI), U.S. Bureau of Labor Statistics (BLS) Producer Price Indices (PPI), Handy-Whitman Index of Public Utility Costs (HWI), and the Gross-Domestic Product (GDP) Chain-type Price Index [14, 15, 16].

Table 4 details which price index was used to escalate each cost metric, as well as the year-dollars the cost was originally reported in. Note that this reporting year is likely to be different that the year the cost estimate is from.

Cost Comparisons

The capital cost metrics used in this study result in a pipeline cost ranging from $65,000 to $91,000/inch-Diameter/mile for pipeline lengths of 250 and 10 miles (respectively) and 3 to 4 million metric tonnes of CO_2 sequestered per year. When project and process contingencies of 30% and 20% (respectively) are taken into account, this range increases to $97,000 to $137,000/inch-Diameter/mile. These costs were compared to contemporary pipeline costs quoted by industry experts such as Kinder-Morgan and Denbury Resources for verification purposes. Table 5 details typical rule-of-thumb costs for various terrains and scenarios as quoted by a representative of Kinder-Morgan at the Spring Coal Fleet Meeting in 2009. As shown, the base NETL cost metric falls midway between the costs quoted for "Flat, Dry" terrain ($50,000/inch-Diameter/mile) and "High Population" or "Marsh, Wetland" terrain ($100,000/inch-Diameter/mile), although the metric is closer to the "High Population" or "Marsh, Wetland" when contingencies are taken into account [17]. These costs were stated to be inclusive of right-of-way (ROW) costs.

Table 4: Summary of Cost Escalation Methodology

Cost Metric	Year-$	Index Utilized
Transport Costs		
Pipeline Materials	2000	HWI: Steel Distribution Pipe
Direct Labor (Pipeline)	2000	HWI: Steel Distribution Pipe
Indirect Costs (Pipeline)	2000	BLS: Support Activities for Oil & Gas Operations
Right-of-Way (Pipeline)	2000	GDP: Chain-type Price Index
CO_2 Surge Tank	2000	CEPI: Heat Exchangers & Tanks
Pipeline Control System	2000	CEPI: Process Instruments
Pipeline O&M (Fixed)	1999	BLS: Support Activities for Oil & Gas Operations
Storage Costs		
Site Screening/Evaluation	1999	BLS: Drilling Oil & Gas Wells
Injection Wells	1999	BLS: Drilling Oil & Gas Wells
Injection Equipment	1999	HWI: Steel Distribution Pipe
Liability Bond	2008	n/a
Pore Space Acquisition	2008	GDP: Chain-type Price Index
Normal Daily Expenses (Fixed)	1999	BLS: Support Activities for Oil & Gas Operations
Consumables (Variable)	1999	BLS: Support Activities for Oil & Gas Operations
Surface Maintenance	1999	BLS: Support Activities for Oil & Gas Operations
Subsurface Maintenance	1999	BLS: Support Activities for Oil & Gas Operations
Monitoring		
Monitoring	2004	BLS: Support Activities for Oil & Gas Operations

Ronald T. Evans of Denbury Resources, Inc. provided a similar outlook, citing pipeline costs as ranging from $55,000/inch-Diameter/mile for a project completed in 2007, $80,000/inch-Diameter/mile for a recently completed pipeline in the Gulf Region (no wetlands or swamps), and $100,000/inch-Diameter/mile for a currently planned pipeline, with route obstacles and terrain issues cited as the reason for the inflated cost of that pipeline [18, 19]. Mr. Evans qualified these figures as escalated due to recent spikes in construction and material costs, quoting pipeline project costs of $30,000/inch-Diameter-mile as recent as 2006 [18, 19].

A second pipeline capital cost comparison was made with metrics published within the 2008 IEA report entitled *CO_2 Capture and Storage: A key carbon abatement option*. This report cites pipeline costs ranging from $22,000/inch-Diameter/mile to $49,000/inch-Diameter/mile (once escalated to December-2006 dollars), between 25% and 66% less than the lowest NETL metric of $65,000/inch-Diameter/mile [20].

The IEA report also presents two sets of flat figure geologic storage costs. The first figure is based on a 2005 Intergovernmental Panel on Climate Change report is similar to the flat figure quoted by other entities, citing

Table 5: Kinder-Morgan Pipeline Cost Metrics [17]

Terrain	Capital Cost ($/inch-Diameter/mile)
Flat, Dry	$50,000
Mountainous	$85,000
Marsh, Wetland	$100,000
River	$300,000
High Population	$100,000
Offshore (150’-200’ depth)	$700,000

storage costs ranging from $0.40 to $4.00 per short ton of CO_2 removed [20]. This figure is based on sequestration in a saline formation in North America.

A second range of costs is also reported, citing CO_2 sequestration costs as ranging from $14 to $23 per short ton of CO_2 [13]. This range is based on a Monte Carlo analysis of 300 gigatonnes (Gt) of CO_2 storage in North America [20]. This analysis is inclusive of all storage options (geologic, enhanced oil recovery, enhanced coal bed methane, etc.), some of which are relatively high cost. This methodology may provide a more accurate cost estimate for large-scale, long-term deployment of CCS, but is a very high estimate for storage options that will be used in the next 50 to 100 years. For example, 300 Gt of storage represents capacity to store CO_2 from the next ~150 years of coal generation (2,200 million metric tonnes CO_2 per year from coal in 2007, assuming 90% capture from all facilities), meaning that certain high cost reservoirs will not come into play for another 100 or 150 years. This $14 to $23 per short ton estimate was therefore not viewed as a representative comparison to the NETL metric.

Results

Figure 1 describes the capital costs associated with the T&S of 10,000 short tons of CO_2 per day (2.65 million metric tonnes per year) for pipelines of varying length. This storage rate requires one injection well and is representative of the CO_2 produced by a 380 MW_g super-critical pulverized coal power plant, assuming 90% of the CO_2 produced by the plant is captured. Figure 2 presents similar information for Fixed, Variable, and total (assuming 100% capacity) operating expenses. In both cases, storage costs remain constant as the CO_2 flow rate and reservoir parameters do not change. Also, transport costs – which are dependent on both pipeline length and diameter – constitute the majority of the combined transport and storage costs for pipelines greater than 50 miles in length.

The disproportionately high cost of CO_2 transport (compared to storage costs) shown in Figures 1 and 2, and the direct dependence of pipeline diameter on the transport capital cost, prompted investigation into the effects of pipeline distance and CO_2 flow rate on pipeline diameter. Figure 3 describes the minimum required pipeline diameter as a function of pipeline length, assuming a CO_2 flow rate of 10,000 short tons per day (at 100%

Figure 1: Capital Cost vs. Pipeline Length

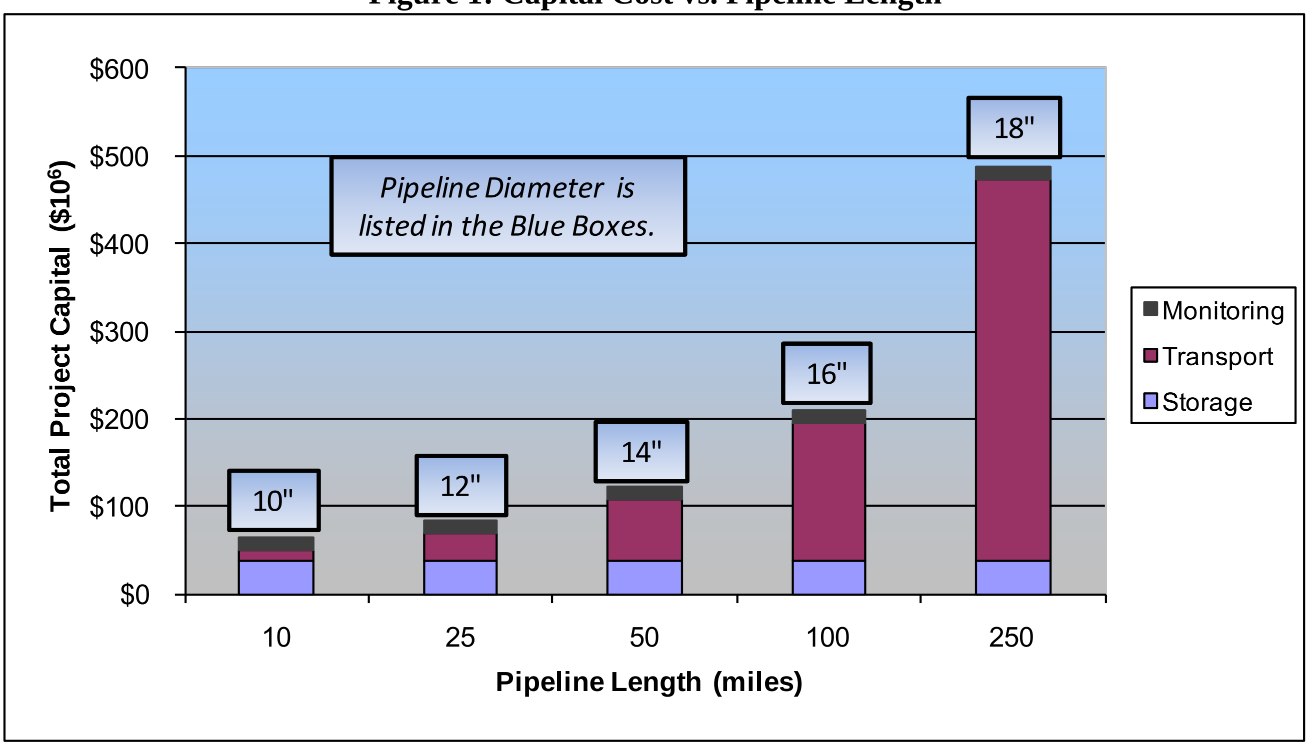
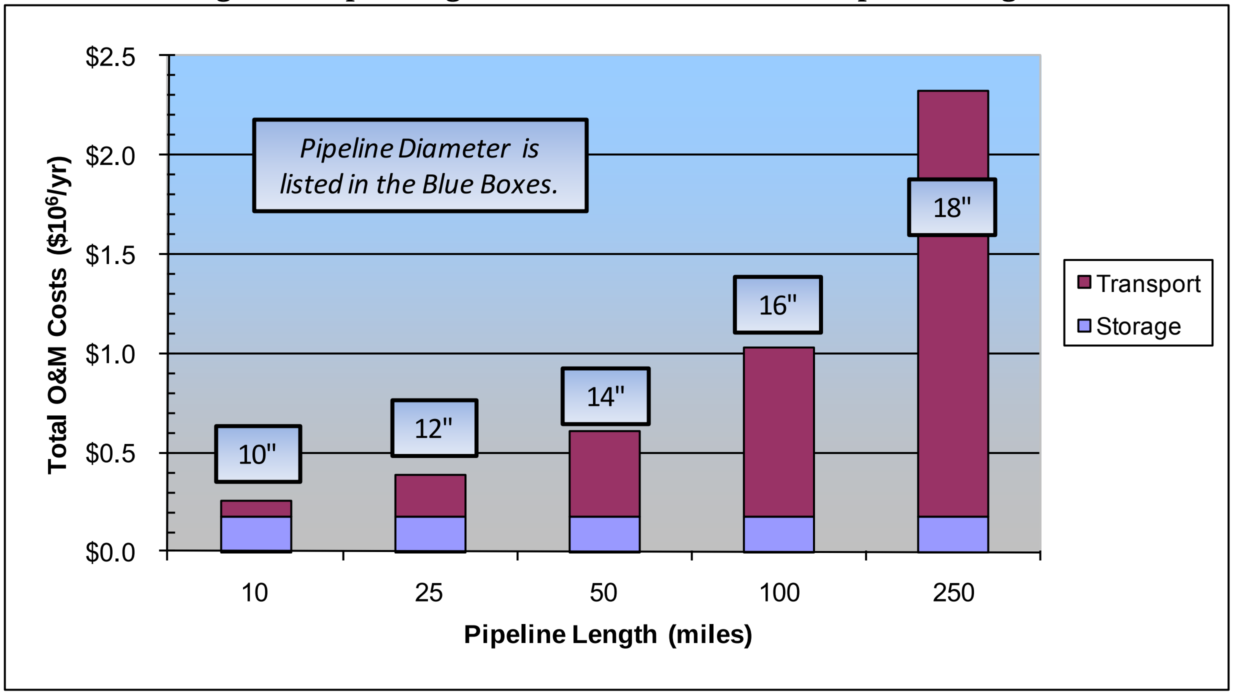


Figure 2: Operating and Maintenance Cost vs. Pipeline Length



utilization factor) and a pressure drop of 700 psi in order to maintain single phase flow in the pipeline (no recompression stages are utilized). Figure 4 is similar except that it describes the minimum pipe diameter as a function of CO_2 flow rate. A sensitivity analysis assessing the use of boost compressors and a smaller pipeline diameter has not yet been completed but may provide the ability to further reduce capital costs for sufficiently long pipelines.

Figure 3: Minimum Pipe Diameter as a function of Pipeline Length

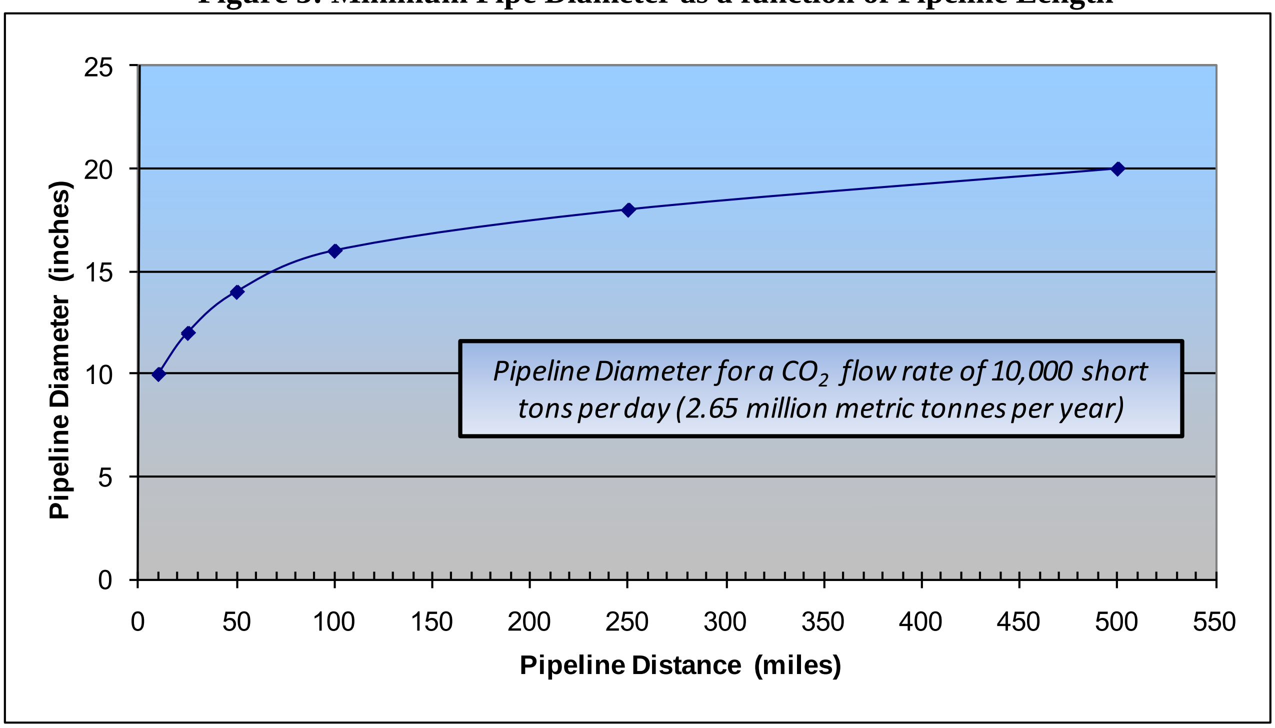
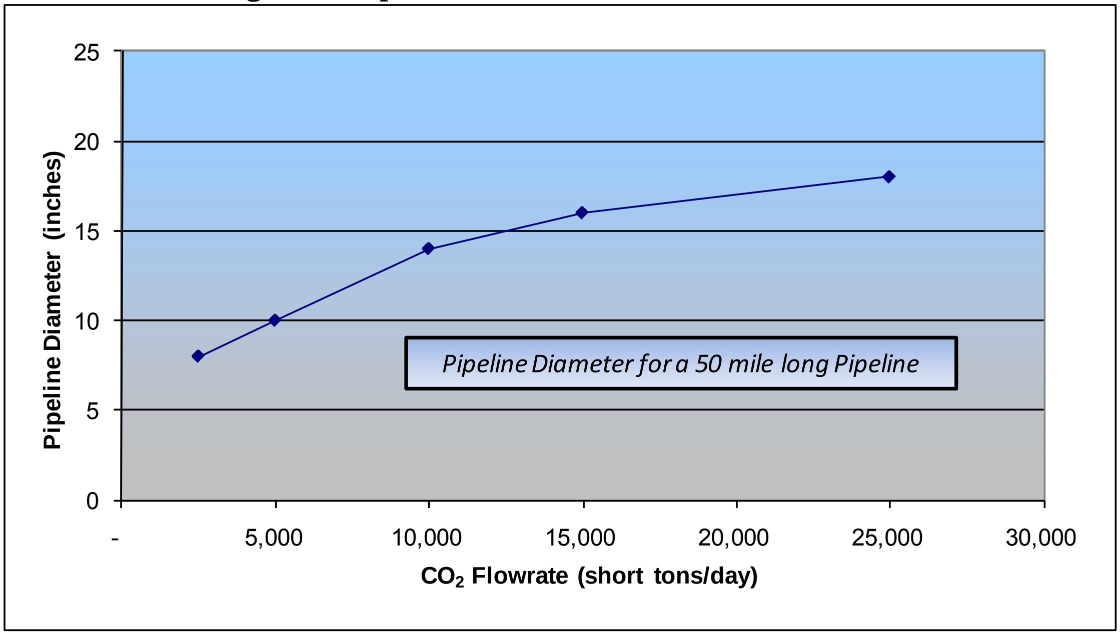


Figure 4: Pipe Diameter as a Function of CO_2 Flow Rate



Figures 5 and 6 describe the relationship of T&S costs to the flow rate of CO_2. The costs are evaluated for a 50 mile pipeline and a 700 psig CO_2 pressure drop over the length of the pipeline. Storage capital costs remain constant up until 10,000 short tons of CO_2 per day, above which a second injection well is needed and the cost increases as shown in Figure 5. A third injection well is needed for flow rates above 21,000 short tons per day and the capital requirement increases again for the 25,000 short tons per day flow rate due to an increase in pipeline diameter. Transport capital costs outweigh storage costs for all cases, as expected based on the results shown in Figure 1.

Unlike storage capital costs, the operating costs for storage constitute a significant portion of the total annual O&M costs – up to 44% at 25,000 short tons of CO_2 per day – as shown in Figure 6. Transport operating costs are constant with flow rate based on a constant pipeline length.

Figure 5: Capital Requirement vs. CO_2 Flow Rate

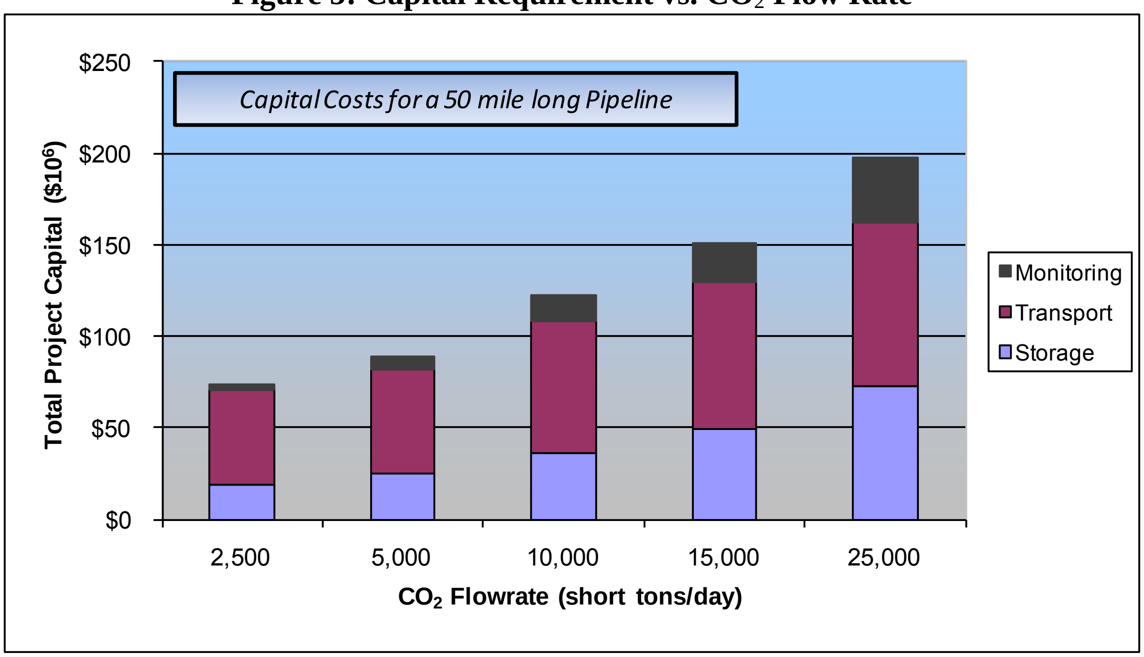
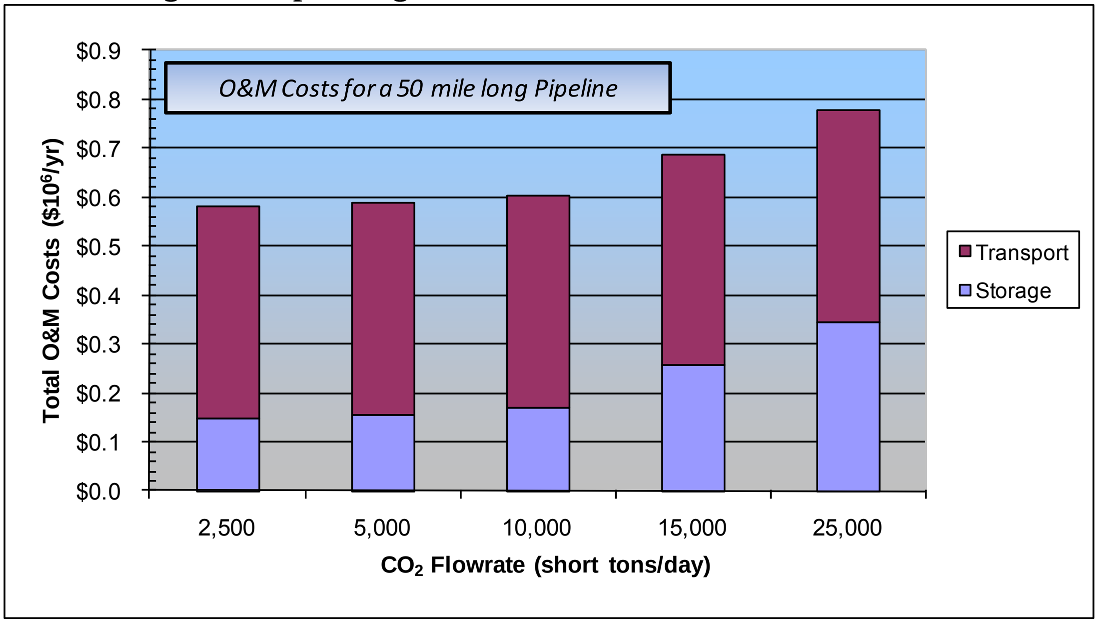
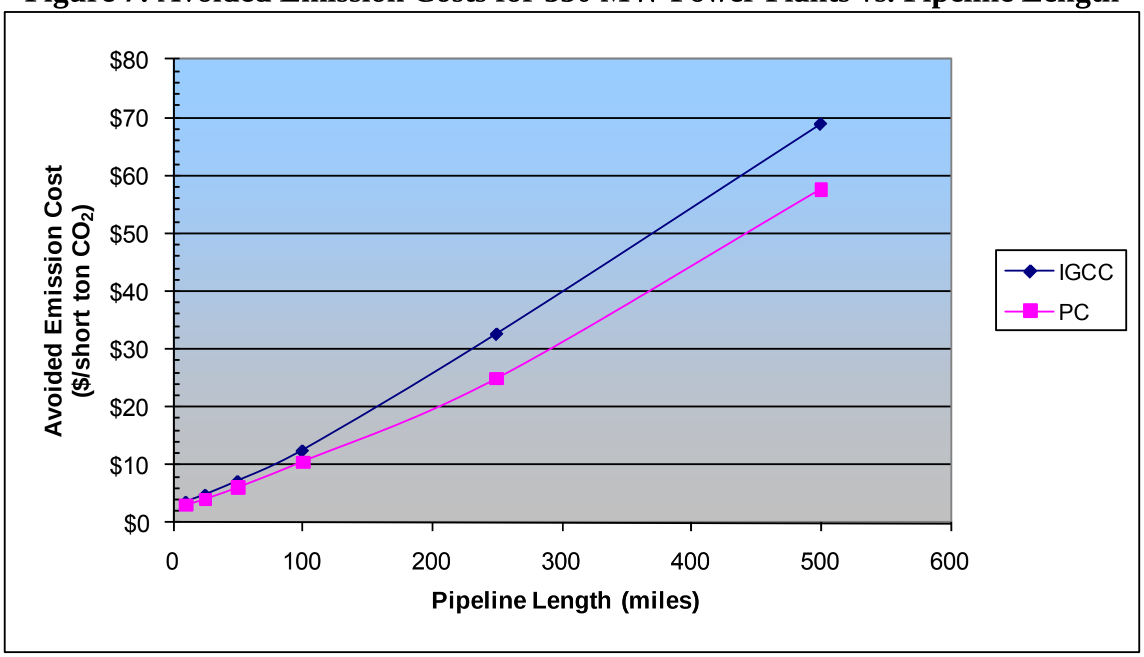


Figure 6: Operating and Maintenance Cost vs. CO_2 Flow Rate



Lastly, CO_2 avoidance and removal costs associated with T&S were determined for PC and IGCC reference plants found in the Baseline Study.[4] Because the CO_2 flow rate is defined by the reference plant, costs were determined as a function of pipeline length. Figure 7 shows that T&S avoided costs increase almost linearly with pipeline length and that there is very little difference between the PC and IGCC cases. This is the result of identical pipelines for each case (same distance, identical diameter) with only a change in capacity factor for each case. Figure 8 is similar to Figure 7 and shows the T&S removed emission cost.

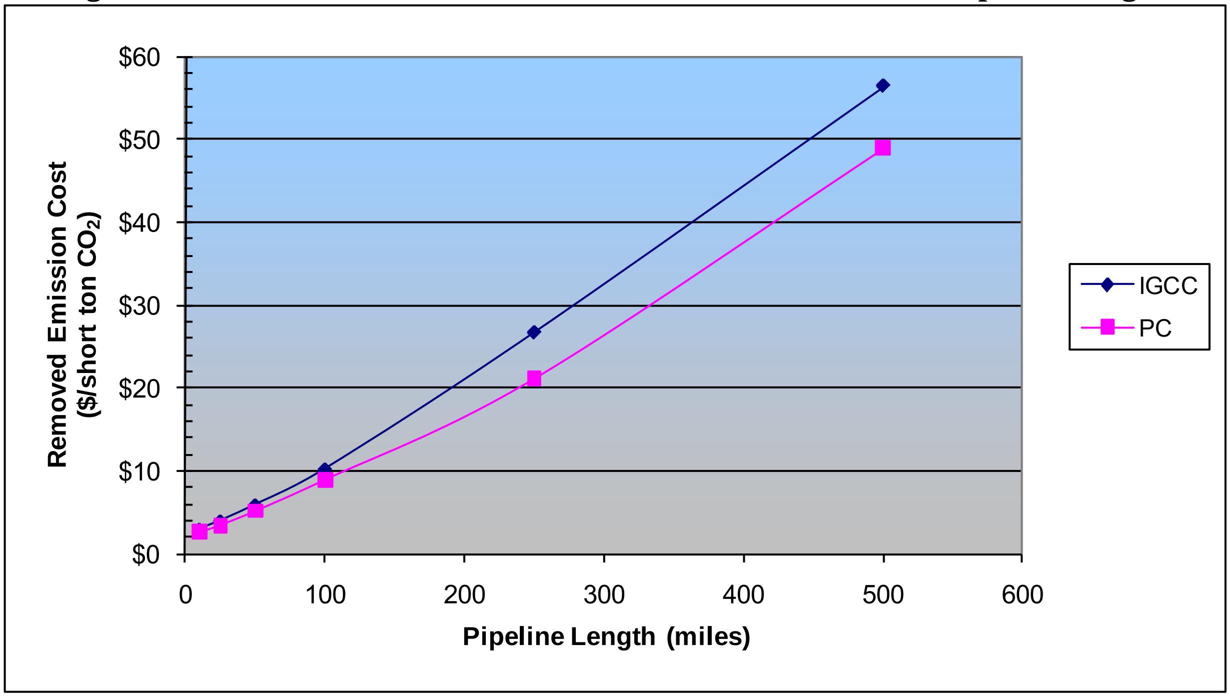
Figure 7: Avoided Emission Costs for 550 MW Power Plants vs. Pipeline Length



[4] Avoided cost calculations are based upon a levelized cost of electricity reported in Volume 1 of NETL's *Cost and Performance Baseline for Fossil Energy Plants* study. Electricity costs are levelized over a 30 year period, utilize a capital charge factor of 0.175, and levelization factors of 1.2022 and 1.1568 for coal costs and general O&M costs, respectively [3].

Addressing our initial topic, we see that our T&S avoided emission cost of \$5 to \$10 per short ton of CO_2 is associated with a pipeline length of 30 to 75 miles for the reference reservoir and our IGCC reference plant, or 50 to 95 miles for our PC reference plant. The T&S removal cost of \$5 to \$10 per short ton of CO_2 is associated with a pipeline length of 40 to 100 miles for an IGCC and 40 to 115 for a PC plant. Both of these ranges apply to the reference reservoir found in Table 1.

Figure 8: Removed Emission Costs for 550 MW Power Plants vs. Pipeline Length



Conclusions

- T&S avoided emission cost of \$5 to \$10 per short ton of CO_2 is associated with a pipeline length of 30 to 75 miles for our reference IGCC plant and the reference reservoir found in Table 1, or pipeline lengths of 50 to 95 miles for the PC plant.

- T&S removed emission cost of \$5 to \$10 per short ton of CO_2 is associated with a pipeline length of 40 to 100 miles for an IGCC and 40 to 115 for a PC plant. Both of these ranges apply to the reference reservoir found in Table 1.

- Capital costs associated with CO_2 storage become negligible compared to the cost of transport (i.e. pipeline cost) for pipelines of 50 miles or greater in length.

- Transport and storage operating costs are roughly equivalent for a 25 mile pipeline but transport constitutes a much greater portion of operating expenses at longer pipeline lengths.

- Transport capital requirements outweigh storage costs, independent of CO_2 flow rate, at a pipeline length of 50 miles and the reference reservoir.

- Operating expenses associated with storage approach transport operating costs for flow rates of 25,000 short tons of CO_2 per day at a 50 mile pipeline length.

Future Work

This paper has identified a number of areas for investigation in future work. These include:

- Investigation into the apparent wide variability in site characterization and evaluation costs, including a sensitivity analysis to be performed to determine the sensitivity of overall project costs across the reported range of values.
- Continued research into liability costs and requirements.
- Further evaluation and sensitivity analysis into the number of land-owners pore space rights will have to be acquired from for a given sequestration project.

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Carbon Capture Research

Before carbon dioxide (CO2) gas can be sequestered from power plants and other point sources, it must be captured as a relatively pure gas. On a mass basis, CO2 is the 19th largest commodity chemical in the United States, and CO2 is routinely separated and captured as a by-product from industrial processes such as synthetic ammonia production, H2 production, and limestone calcination.

Existing capture technologies, however, are not cost-effective when considered in the context of sequestering CO2 from power plants. Most power plants and other large point sources use air-fired combustors, a process that exhausts CO2 diluted with nitrogen. Flue gas from coal-fired power plants contains 10-12 percent CO2 by volume, while flue gas from natural gas combined cycle plants contains only 3-6 percent CO2. For effective carbon sequestration, the CO2 in these exhaust gases must be separated and concentrated.

CO2 is currently recovered from combustion exhaust by using amine absorbers and cryogenic coolers. The cost of CO2 capture using current technology, however, is on the order of $150 per ton of carbon - much too high for carbon emissions reduction applications. Analysis performed by SFA Pacific, Inc. indicates that adding existing technologies for CO2 capture to an electricity generation process could increase the cost of electricity by 2.5 cents to 4 cents/kWh depending on the type of process.

Furthermore, carbon dioxide capture is generally estimated to represent three-fourths of the total cost of a carbon capture, storage, transport, and sequestration system.

The program is pursuing evolutionary improvements in existing CO2 capture systems and also exploring revolutionary new capture and sequestration concepts. The most likely options currently identifiable for CO2 separation and capture include:

- Absorption (chemical and physical)
- Adsorption (physical and chemical)
- Low-temperature distillation
- Gas separation membranes
- Mineralization and biomineralization

Opportunities for significant cost reductions exist since very little R&D has been devoted to CO2 capture and separation technologies. Several innovative schemes have been proposed that could significantly reduce CO2 capture costs, compared to conventional processes. "One box" concepts that combine CO2 capture with reduction of criteria pollutant emissions are being explored as well.

Examples of activities for this program element include:

- Research on revolutionary improvements in CO2 separation and capture technologies
    - new materials (e.g., physical and chemical absorbents, carbon fiber molecular sieves, polymeric membranes);
    - oxygen-enhanced combustion approaches;
- Development of retrofittable CO2 reduction and capture options

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for existing large point sources of CO2 emissions such as electricity generation units, petroleum refineries, and cement and lime production facilities;

- Integration of CO2 capture with advanced power cycles and technologies and with environmental control technologies for criteria pollutants.

8. Furnaces / Process Heaters

Approximately 30% of the fuel used in the chemical industry is used in fired heaters. The average thermal efficiency of furnaces is estimated at 75-90% (Petrick and Pellegrino, 1999). Accounting for unavoidable heat losses and dewpoint considerations the theoretical maximum efficiency is around 92% (HHV) (Petrick and Pellegrino, 1999). This suggests that typical savings of 10% can be achieved in furnace and burner design, and operations. In the following section, various improvement opportunities are discussed, including improving heat transfer characteristics, enhancing flame luminosity, installing recuperators or air-preheaters and improved controls. New burner designs aim at improved mixing of fuel and air and more efficient heat transfer. Many different concepts are developed to achieve these goals, including lean-premix burners (Seebold et al., 2001), swirl burners (Cheng, 1999), pulsating burners (Petrick and Pellegrino, 1999) and rotary burners (U.S. DOE-OIT, 2002c). At the same time, furnace and burner design has to address safety and environmental concerns. The most notable is the reduction of NOx emissions. Improved NOx control will be necessary in many chemical industries to meet air quality standards.

Heat generation. In heat generation, chemical or electrical energy is converted into thermal energy. A first opportunity to improve the efficiency of heat generation is to control the air-to-fuel ratio in furnaces. Badly maintained process heaters may use excess air. This reduces the efficiency of the burners. Excess air should be limited to 2-3% oxygen to ensure complete combustion. Typical energy savings of better controlled air to fuel ratios vary between 5 and 25% (U.S. DOE-OIT, 2004c). The use of up-to-date exhaust gas oxygen analyzer can help to maintain optimal air-to-fuel ratios. At the Deer Park facility of Rohm and Haas, old exhaust oxygen analyzers resulted in delayed reading and made it more difficult to accurately monitor combustion conditions. Installation of three new analyzers in the furnace ducts resulted in real-time readings of oxygen levels and better process control (U.S. DOE-OIT, 2006d). Typical payback times of projects aiming to reduce combustion air flows by better control are around 6 months or less (IAC, 2006).

In many areas new air quality regulation will demand industries to reduce NOx and VOC emissions from furnaces and boilers. Instead of installing expensive selective catalytic reduction (SCR) flue-gas treatment unit's new burner technology allows to reduce emissions dramatically. This will result in cost savings as well as help to decrease electricity costs for the SCR. In a plant-wide assessment of a Bayer Polymers plant in New Martinsville, West Virginia (U.S. DOE-OIT, 2003d), the replacement of natural gas and hydrogen fuelled burners with efficient low NO_x design burners was identified as a project that could result in 2% efficiency improvements saving 74,800 MMBtu per year and annual CO_2 emission reductions of 8.46 million pounds. Estimated pay-back time for the project was 13 months at total project costs of $ 390,000. Efficient use of existing burners can also help to save energy and reduce NO_x emissions. In an energy-efficiency assessment of the Anaheim, California site of Neville Chemical Company (U.S. DOE-OIT, 2003e), a potential project was identified in which only a single natural gas fuelled incinerator (instead of the two operated) can be used to incinerate Volatile Organic Compounds (VOCs). This would result in energy savings of 8 TBtu per year. Project costs were estimated at $57,500 with a payback period of 1.3 years.

Heat transfer and heat containment in heaters. Improved heat transfer within a furnace, oven or boiler can result in both energy savings and productivity gains. There can be several ways to improve heat transfer such as the use of soot blowers, burning off carbon and other deposits from radiant tubes and cleaning the heat exchange surfaces. Typical savings are 5-10% (U.S. DOE-OIT, 2004c). Ceramic coated furnace tubes can improve heat transfer of metal process tubing, while stabilizing the process tube's surface. They can improve energy efficiency, increase throughput or both. Increased heat transfer is accomplished by eliminating the insulating layers on the fire-side of process tubing that form during operation. Applications in boilers and petrochemical process units have shown efficiency improvements between 4% and 12% (Hellander, 1997). Heat containment can be improved by numerous measures, including reducing wall heat losses (typical savings 2-5%), furnace pressure control (5-10%), maintenance of door and tube seals (up to 5%), reducing cooling of internal parts (up to 5%) and reducing radiation heat losses (up to 5%). Typical payback times of project aiming to reduce heat losses and improved heat transfer are between 3 months and 1 year (IAC, 2006).

Flue gas heat recovery. Reducing exhaust losses (e.g. by the measures described above) should always be the first concern in any energy conservation program. Once this goal has been met, the second level should be considered – recovery of exhaust gas waste heat. Use of waste heat to preheat combustion air is commonly used in medium to high temperature furnace. It is an efficient way of improving the efficiency and increasing the capacity of a process heater. The flue gases of the furnace are used to preheat the combustion air. Every 35°F drop in the exit flue gas temperature increases the thermal efficiency of the furnace by 1% (Garg, 1998). Typical fuel savings range between 8 and 18%, and is typically economically attractive if the flue gas temperature is higher than 650°F and the heater size is 50 MMBtu/hr or more (Garg, 1998). The optimum flue gas temperature is also determined by the sulfur content of the flue gases to reduce corrosion. When adding a preheater the burner needs to be re-rated for optimum efficiency. Energy recovery can also be applied in catalytic oxidizers used to reduce volatile organic compound (VOC) emissions, e.g. via a regenerative heat exchanger in the form of a ceramic packing (Hydrocarbon Processing, 2003).

Heat from furnace exhaust gases or from other sources (discussed in Chapter 9) can also be used in waste heat or quench boilers to produce steam (discussed in Chapter 7) or to cascade heat to other applications requiring lower temperature heat as part of the total plant heat demand and supply optimization (see also Chapter 9 on process integration). Recovering thermal energy in the form of steam from incineration of waste products should be considered carefully. Because a waste stream is used, the stream will have variations in contaminant and component concentrations which influence to load on the boiler. Also, the contaminants might create acid gases causing corrosion problems for the boiler. These aspects should be taken into account in designing waste heat boilers (Ganapathy, 1995).

The benefits from heat recovery projects have been shown in various case studies. In an energy-efficiency assessment of the 3M Hutchinson, Minnesota, facilities, heat recovery from thermal oxidizers in the form of low-pressure steam was identified as a project that could save 210,000 MMBtu of fuels (U.S. DOE-OIT, 2003f). Project capital costs are $913,275 with avoided first year energy expenses of $772,191. In an audit of the W.R. Grace facility in

Curtis Bay, Baltimore, Maryland, a project was identified that uses flue gas heat in an air-to-water heat exchanger for fresh water heating, reducing the original steam demand for heating this water by 31%. Capital costs for this project are estimated at $346,800 with a relatively long payback period of 5.3 years (U.S. DOE-OIT, 2003g). In a project in the UK, heat recovery from an incinerator via a run-around coil system yielded energy savings of 9 TBtu per year with a payback time of 1.5 years (Best Practice Programme, 1991). Heat recovery from the SO_2 containing gases of a sulphur burning process in a sulphonation plant in Norway resulted in energy savings of 4,800 MWh per year (CADDETT, 2000b). Investment costs were $800,000 and the simple payback time of the project 6 years.

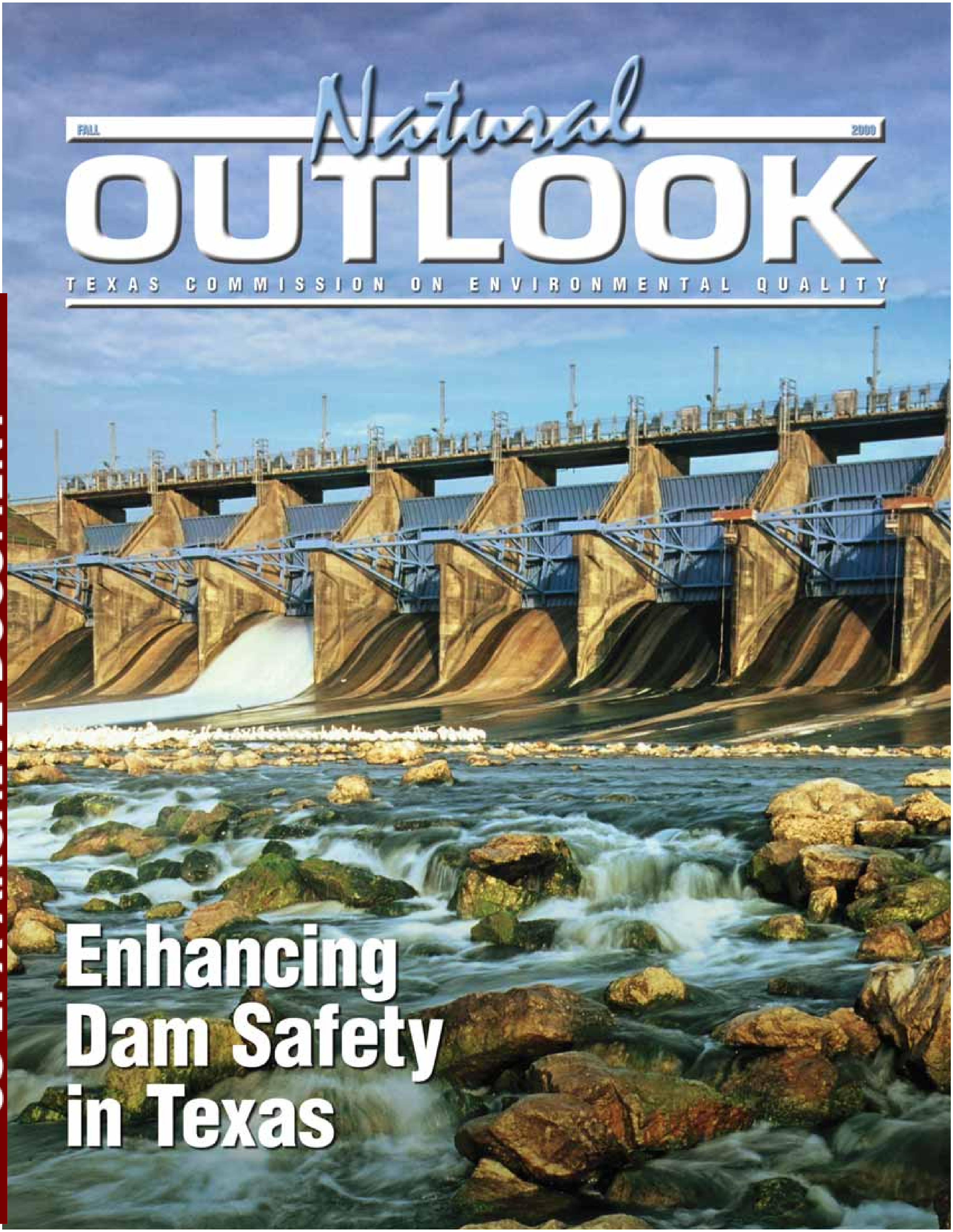
Others – controls, maintenance and electric heaters. Energy losses can also be reduced via improved process control. Improved control systems can help to improve aspects such as material handling, heat storage and plant turndown. Typical savings of improved control systems can be in the range of 2-10% (U.S DOE-OIT, 2004c). A relatively small part of the heating requirements in the chemical industry is supplied by electrically heated devices. Still, electric heaters account for approximately 3% of the electricity use of the chemical industry (U.S. DOE-OIT, 2006a). Not in all cases, electric heating is the right choice (Best Practice Programme, 2001) and in a number of cases, improvements are possible. For example, in an energy-efficiency assessment of the Anaheim, California site of Neville Chemical Company (U.S. DOE-OIT, 2003e), a potential project was identified in which electric heaters are to be replaced with a natural-gas fired heat fired system, using 557 MMBtu per year, but replacing 114,318 kWh of electricity. Project costs for the project were estimated at $6,100 with a payback time of 0.9 years. In an assessment of a Formosa Plastics Corporation polyethylene plant (U.S. DOE-OIT, 2005a), improvement of an electrically heated extruder was identified as a project that could result in electricity savings of 1,488,000 kWh annually, resulting in annual cost savings of $59,520. The estimated payback time for the projects was 0.1 year.

APPENDIX E
GENERAL SUPPORTING DOCUMENTATION

AIR PERMIT APPLICATION

JACKSON COUNTY GAS PLANT

ETC TEXAS PIPELINE, LTD.


FALL
Natural
OUTLOOK
TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
Enhancing
Dam Safety
in Texas

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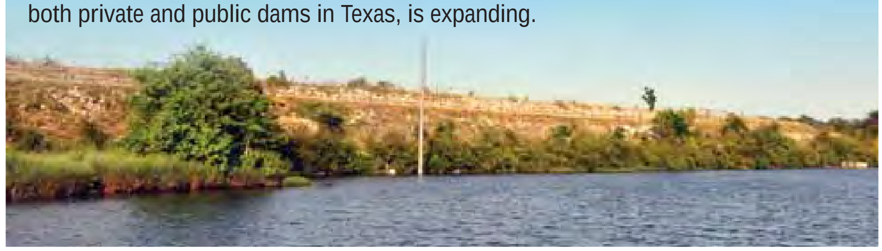
Natural OUTLOOK

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Exploring environmental issues and challenges in Texas



COVER: Lake Livingston Dam

Photo courtesy of Trinity River Authority

Using Water Wisely

Drought contingency planning helps keep the water flowing for Texans

Any Texan who has experienced a sizzling hot day during a seemingly never-ending Texas "dry spell" definitely knows the worth of water. But not every Texan who turns on a tap is aware of the careful planning required to keep that water flowing, even during a drought.

Planning for Drought

During a drought, there is less rainfall and less water available for human use. Water utilities throughout Texas must plan ahead to reduce the impact of droughts, reduce peak demand, and extend their water supplies.

Drought contingency planning in Texas grew out of legislation passed in 1997 after a severe 1996 drought, when 86 percent of Texas counties qualified for emergency aid. The Texas Legislature directed the TCEQ to adopt rules establishing common drought plan requirements for water suppliers.

As a result, around 736 irrigation districts, wholesale public water suppliers, and retail public water suppliers that serve 3,300 connections or more are required to submit drought contingency plans to the TCEQ every five years. Retail public water suppliers that serve fewer than 3,300 connections must prepare and adopt a drought contingency plan and have it available to show to the TCEQ upon request.

Implementing Drought Triggers

Drought contingency plans vary by supplier; however, a common feature is a structure that imposes increasingly stringent drought response measures in successive stages as water supply conditions worsen. Most suppliers define three to five drought response stages that include "triggering" criteria for each stage.

Once triggered, Stage I of a contingency plan might start, for example, with a voluntary watering schedule. If the desired reduction in water use is not achieved, mandatory restrictions on some outdoor water uses might be the next stage of the plan. If these efforts fail to sufficiently reduce usage, a ban on all outdoor use of water might be implemented in the final stage.

Conserving Water

Many water suppliers also have water conservation plans. A water conservation plan differs from a drought contingency plan in that it centers around the everyday responsible stewardship of water, whereas contingency measures are implemented only as a matter of necessity, when a supplier needs to manage a water-supply or -demand issue. Conservation can extend water supplies and potentially prevent the necessity of implementing a drought contingency plan.

Making Every Drop Count

Each and every Texan can help keep the water flowing by supporting their supplier's contingency efforts during a drought and by making water conservation a part of their everyday activities.

For water conservation tips, visit the Texas Water Development Board's "Save Water" Web page, at www.twdb.state.tx.us/data/drought/save_water2.asp. ★

Partnership Protects "America's Sea"

The Gulf of Mexico Alliance releases plan for healthy and resilient coasts

The Gulf of Mexico is the ninth largest body of water in the world, with a total area of nearly 600,000 square miles. Sometimes called "America's Sea," it is bounded by Florida, Alabama, Mississippi, Louisiana, and Texas on the north; Mexico on the west and south; and the island of Cuba on the southeast.

The gulf sustains an abundance of marine life, 28 different species of whales and dolphins, and complex coral reef communities. Its coastal areas, which contain half the wetlands in the United States, are home to vital natural resources, nesting waterfowl habitat, colonial waterbird rookeries, and many endangered species, such as the Kemp's Ridley sea turtle.

Beautiful beaches and rich recreational fishing grounds support a booming tourism industry. And with one of the most developed oil and gas industries in the world, as well as several ports that lead the nation in total commerce, it is easy to see why the Gulf of Mexico is critical to the U.S. economy.

The health of the gulf, however, faces many serious challenges. Key coastal habitat is threatened by increased coastal development, sea level rise, shoreline erosion, and land subsidence. The Mississippi River and its tributaries transport nutrient runoff from agricultural activity in 31 upstream states to the gulf, stimulating an overgrowth of algae. This algae sinks and decomposes, helping to make the gulf the world's second largest "zone of hypoxia," or area of water with little to no oxygen. This annually recurring "dead zone" results in the loss of fish, shellfish, and plants.

Gulf States Join Forces

In 2004, recognizing that the economies and quality of life of the citizens in their states were linked to the ecological health of the Gulf of Mexico, the governors of Alabama, Florida, Louisiana, Mississippi, and Texas joined forces to form the Gulf of Mexico Alliance. This partnership, supported by thirteen federal agencies, was the

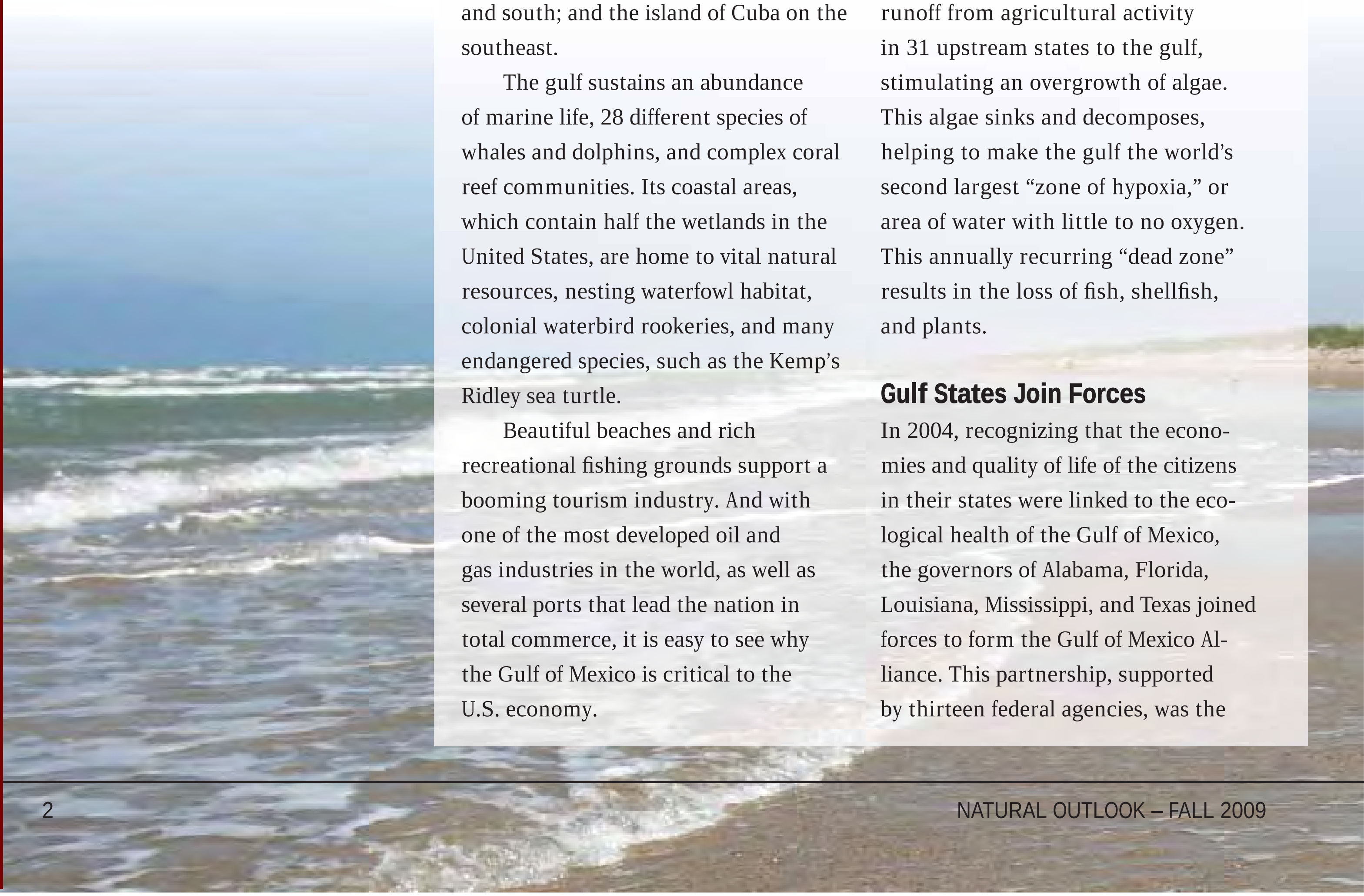


Photo courtesy of Kevin Stillman/TxDOT

beginning of a regional collaborative effort to improve the health of the Gulf of Mexico.

The governor of each state appointed one or more representatives to provide the vision for and make strategic decisions about alliance activities. TCEQ Commissioner Buddy Garcia was designated to represent Texas on the Alliance Management Team.

"The economic vitality of the Gulf Coast depends on the ecological health of the Gulf of Mexico," says Garcia. "Many of the challenges we face in the gulf region cross state lines. Through the Gulf of Mexico Alliance, the five gulf states are able to combine expertise and resources to resolve shared issues."

Taking Action for Coastal Health

The first project undertaken by the alliance was to develop the Governors' Action Plan for Healthy and Resilient Coasts. Released in 2006, this three-year plan identified specific actions needed to improve the health of coastal areas. The results exceeded initial expectations and included the following accomplishments:

- Coastal Ecosystem Learning Centers were established in each of the five gulf states and Veracruz, Mexico.
- A Regional Sediment Management Master Plan was drafted. This plan provides a framework for better management of gulf sediment resources, facilitating a reduction in coastal erosion and storm damages, as well as the restoration of coastal habitats.
- Binational workshops designed to standardize the identification of harmful algal blooms and methods of field sampling were conducted in Texas, Florida, and Mexico.
- An ecosystem data portal was established. The portal will be used by resource managers to evaluate habitat extent and changes over time.
- A regional Nutrient Criteria Research Framework was developed. This has led to a better understanding of nutrient impacts to gulf ecosystems, as well as a coordinated approach to managing them.

Photo courtesy of Chase Fountain/Texas Parks and Wildlife Department

Photo courtesy of Texas Parks and Wildlife Department

Facts about the Gulf of Mexico

The Gulf of Mexico is one of the world's most ecologically and economically productive bodies of water, according to TCEQ Commissioner Buddy Garcia, who was appointed by Gov. Rick Perry to serve as Texas representative on the Gulf of Mexico Alliance Management Team. "Yet many people don't realize just how vital the gulf is to our nation and to the economy," says Garcia.

Here are a few facts about the Gulf of Mexico:

- **The gulf yields 69 percent of the shrimp and 70 percent of the oysters caught in the U.S.**
- **In 2008, recreational anglers caught 190 million fish in the Gulf of Mexico and surrounding waters, for a total weight of 73.6 million pounds.**
- **Four of the nation's top seven fishing ports are located on the Gulf Coast.**
- **The gulf yields more finfish, shrimp, and shellfish annually than the south- and mid-Atlantic, Chesapeake, and New England areas combined.**
- **Seven of the nation's top ten ports in terms of tonnage or cargo value are located on the Gulf Coast.**
- **According to the Minerals Management Service, offshore operations in the gulf produce a quarter of the domestic natural gas in the U.S. and one-eighth of its oil.**
- **More than a third (38%) of the U.S. shipbuilding industry is located along the Gulf Coast.**
- **With a watershed stretching from the Rockies to the Appalachians, the gulf provides much of the atmospheric moisture for North America.**
- **The gulf provides critical habitats for 75 percent of the migratory waterfowl that traverse the United States.**

Photo courtesy of Chase Fountain/Texas Parks and Wildlife Department

The Alliance Releases New Action Plan

Building on the successes of the first action plan, in 2008 the gulf states and their partners started working to develop a second plan. Released in June of 2009, the Governors' Action Plan II is a farther-reaching, five-year regional plan that, according to the alliance, "sets a course for actions designed to improve the health of coastal ecosystems and economies of the gulf in ways that a single entity could not achieve."

As in the first plan, Action Plan II identifies six regionally significant issues that can be effectively addressed through increased collaboration at the local, state, and federal levels:

- Water quality for healthy beaches and seafood
- Habitat conservation and restoration
- Ecosystems integration and assessment
- Reducing the impacts of nutrients on coastal ecosystems
- Coastal community resilience
- Environmental education

Each of these six issues is supported by a Priority Issue Team (PIT), a stakeholder group composed of scientific and technical experts from various governmental agencies, academia, nonprofit organizations, and private businesses in the five gulf states.

"The meat of the work for the priority issues happens at the PIT level," says Becky Walker, who handles coastal policy matters for Garcia and also serves as the alternate Texas representative on the Alliance Management Team. "The members of each team work together on a regular basis to identify specific actions that they are going to address and implement."

"The Gulf of Mexico Alliance gives us a chance to focus on our commonalities and what we can do together to impact the region," she says.

Action Plan II Addresses Challenges

Actions identified in Action Plan II collectively address four major challenges: sustaining the gulf economy, improving the health of the gulf ecosystem, mitigating the impacts of and adapting to climate changes, and mitigating any harmful effects on coastal water quality.

"The alliance is committed to a healthy Gulf of Mexico region," says Garcia, "and Action Plan II provides the blueprint for success."

To learn more about the Gulf of Mexico Alliance or to read Action Plan II in its entirety, visit **www.gulfofmexicoalliance.org**. To find out about important issues facing the Gulf Coast, visit the alliance's Environmental Education Network Web site, at **www.gulfallianceeducation.org**.

Photo courtesy of Michael A. Murphy/TxDOT

New Laws Address Agency Priorities

Legislation lays groundwork for cleaner environment

The 81st Texas Legislature concluded its regular session in June after passing 235 bills that affect TCEQ programs and address agency priorities. Following are some of the laws passed during the session.

Air

House Bill 1796

HB 1796 includes legislation pertaining to offshore geologic storage of carbon dioxide, the Texas Emissions Reduction Plan, a New Technology Implementation Grant Program, and greenhouse gas reporting requirements.

- **Offshore Geologic Storage of Carbon Dioxide**

  HB 1796, which lays the groundwork for Texas to develop an offshore carbon dioxide storage repository in state-owned submerged land, affects several agencies, including the TCEQ, the General Land Office, the University of Texas Bureau of Economic Geology, and the School Land Board.

  As an important part of the overall effort, the TCEQ will develop and adopt standards for monitoring, measuring, and verifying the permanent storage status of an offshore repository, ensuring that any standards adopted by the agency comply with EPA regulations.

- **The Texas Emissions Reduction Plan**

  HB 1796 extends the Texas Emissions Reduction Plan (TERP) until 2019. TERP is a comprehensive set of incentive programs aimed at reducing emissions in areas of the state identified as in nonattainment or near-nonattainment of federal ozone standards. The legislation allocated TERP funds as follows:

Emissions Reduction Incentive Grants (ERIG) Program, which includes the Clean School Bus Program, the Texas Clean Fleet Program, and the New Technology Implementation Grant Program	87.5%
New Technology Research and Development (NTRD)	9.0%
TERP administration	2.0%
Energy Systems Lab at Texas Engineering Experiment Station (TEES)	1.5%

- **New Technology Implementation Grant Program**
  HB 1796 also establishes the New Technology Implementation Grant (NTIG) program for the implementation of new technologies that reduce emissions from facilities and other stationary sources. Projects that could be eligible for the NTIG program include advanced clean energy projects, new technology projects that reduce emissions of regulated pollutants from point sources involving capital expenditures in excess of $500 million, and electricity storage projects related to renewable energy.

- **Greenhouse Gas Reporting Requirements**
  The TCEQ will work with the Texas Railroad Commission and the Texas Public Utilities Commission to review the development of federal greenhouse gas reporting requirements. The TCEQ will also establish an inventory of voluntary actions taken by state agencies and by businesses in the state since Sept. 1, 2001, to reduce carbon dioxide emissions. The TCEQ will work with the EPA to receive credit for early action under any federal rules that may be adopted for the regulation of greenhouse gases.

Senate Bill 1759

Texas Clean Fleet Program

SB 1759 creates a program that provides grants to fleet owners who replace qualifying diesel-powered vehicles with alternative-fuel or hybrid vehicles. The Texas Clean Fleet Program will be funded through TERP Emissions Reduction Incentives Grant (ERIG) funds.

continued on page 17

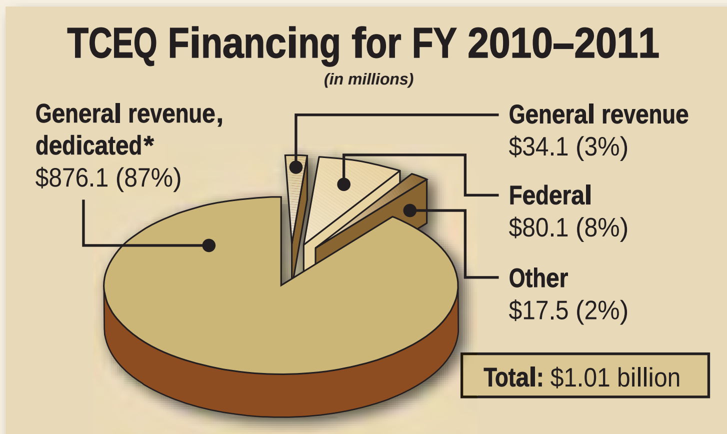
Agency Appropriations

The TCEQ will receive $1.01 billion for the 2010–2011 biennium, which began Sept. 1, 2009. Of this, $964.2 million is appropriated under the Appropriations Act (SB 1) and $43.6 million is appropriated through a supplemental appropriations bill to fund the Texas Emissions Reduction Plan (TERP), the state Superfund program, and response to natural disasters.

Included in the $964.2 million appropriation is $33.2 million for exceptional items such as the implementation of the new federal ozone standard, enhancements to the agency's Dam Safety Program, increased cleanup activities in the state Superfund program, an increase in grant funds for air quality planning, and information resource needs.

The Legislature also authorized an additional 66 full-time equivalent (FTE) positions for exceptional items and contingency riders, which include:

- 24 additional FTEs for enhancements to the Dam Safety Program
- 30 additional FTEs for implementation of the new ozone standard
- 2 additional FTEs to inspect a new low-level radioactive site in Andrews County
- 10 additional FTEs for contingency riders



*Fees assessed by the TCEQ and deposited to TCEQ accounts

Appropriations for the 2010–2011 biennium include the following program changes:

TCEQ Program	Increase or Decrease from 2008–2009 Biennium	Total for 2010–2011 Biennium
State Superfund Program	+ $8 million	$64.0 million
Air Quality Planning Grants	+ $2 million	$7.1 million
Petroleum Storage Tank Program	– $20 million	$52.3 million
Texas Emissions Reduction Plan	– $68 million	$233.0 million
Dam Safety Program (new funding)	N/A	$2.5 million

Enhancing Dam

Dam safety program expands

By Liz Carmack, contributing writer

Dams are a vital part of the national infrastructure and provide an infinite number of benefits to society. Dams provide drinking water, flood protection, renewable hydroelectric power, navigation, irrigation, and recreation. However, dams can also represent a public safety issue. A dam failure can result in loss of life, economic disaster, and extensive environmental damage.

The TCEQ Dam Safety Program is tasked with mitigating the risk of dam failures in Texas. With an infusion of $2.5 million in funding over the 2010–2011 biennium from the 81st Texas Legislature, and with plans to increase the number of inspectors in fiscal year 2011, the program is expanding.

Emphasis on Inspections

The program expansion was needed. Texas has the largest number of state-regulated dams in the country—7,139. (An additional 86 dams are federally operated and not under the TCEQ's purview.)

State-regulated dams are generally earthen and can range from 6 feet to 200 feet in height. Roughly 60 percent are privately owned. Another 24 percent are owned by soil and water conservation districts. The rest are the property of state and local governments, water districts, river authorities, and public utilities.

Dam Safety Program staff are responsible for ensuring that these structures, scattered across the state, are properly constructed and maintained. Their many duties include reviewing and approving plans and specifications for new dams or dam modifications, performing hydrologic and hydraulic analyses of dams, and inspecting existing dams and dams that are under construction.

"Our primary emphasis now is on dam inspection," says Warren Samuelson, manager of the TCEQ's Dam Safety Program. "Our goal is to inspect all dams that have a high-hazard or a significant-hazard rating within a five-year period ending August 2011."

Dams classified as high hazard or significant hazard have the potential to harm life or property and the environment should they fail. In Texas, 1,729 dams fall into these two classifications—963 are high-hazard dams and 766 are significant-hazard dams. According to the Texas Section of the American Society of Civil Engineers, 75 percent of the high-hazard dams were built before 1975. The age of this critical infrastructure heightens the importance of the agency's stepped-up inspection program.

The Dam Safety Program is two-thirds of the way toward meeting

Photo by Esperanza White, courtesy of the Upper Brushy Creek WCID

Upper Brushy Creek WCID's Dam No. 6 in Cedar Park.

Safety in Texas

its inspection goal. Staff and TCEQ contractors inspected 292 high- and significant-hazard dams in 2007, 316 in 2008, and 550 as of June of this year.

The most frequent problems inspectors find include excessive vegetative growth, damage caused by animals burrowing into the dam, blockage of the spillway with trees or debris, erosion and undercutting of concrete structures, erosion of the spillway, damage to spillway pipes, and water seepage below the dam.

"Sometimes we'll see cracking on the dam, especially with the weather as dry as it is, and sometimes we'll see earthen slides," Samuelson says. "Sometimes there is such excessive vegetative growth we can't even inspect the dam. In that case, we require them to remove the vegetation."

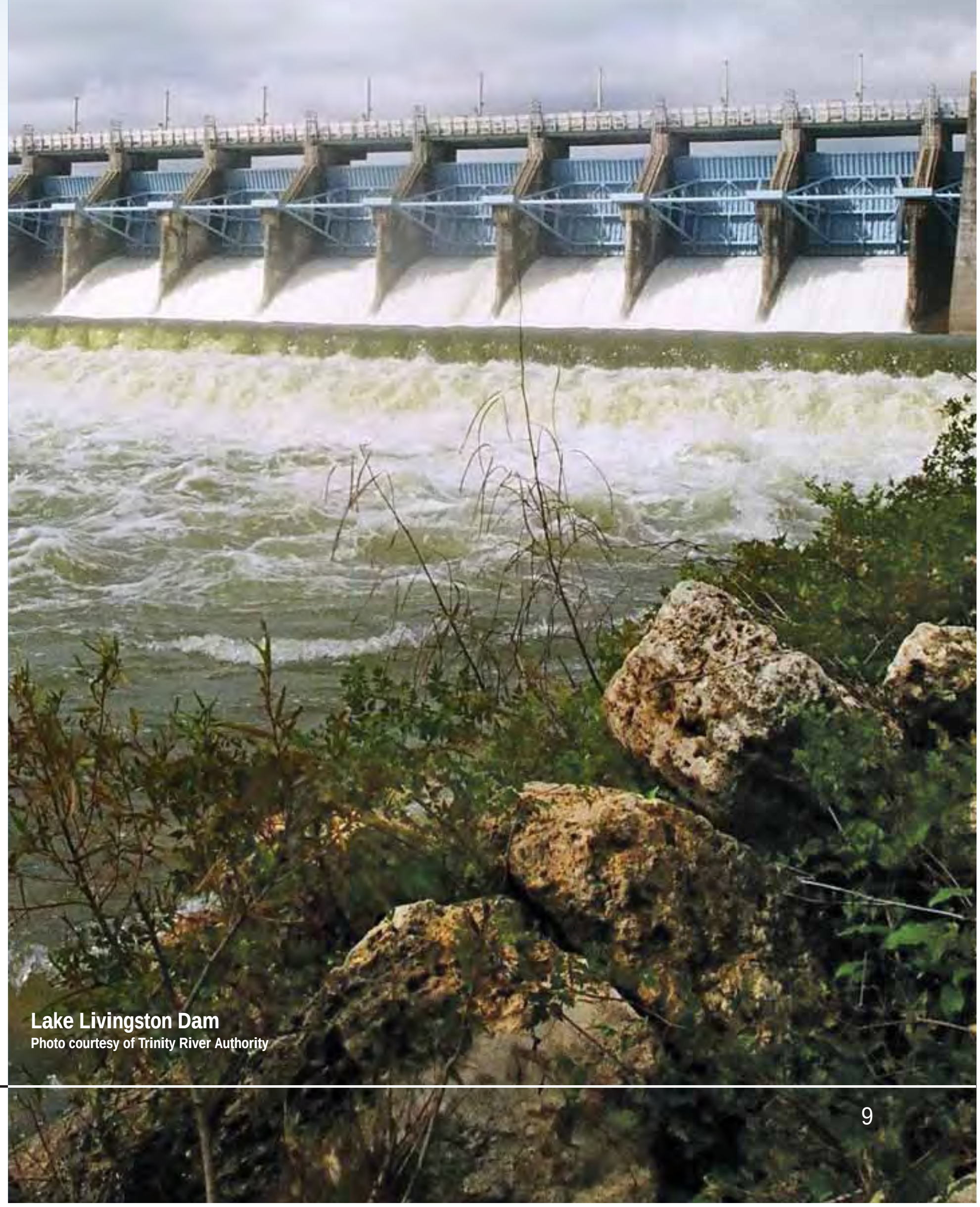
Following an inspection, the TCEQ provides a report to the dam's owner. If any problems are found, the agency outlines them and the required actions needed to improve safety. Within 45 days, the owner is required to produce a plan and schedule for addressing the agency's findings.

The agency depends on the owner to set the deadline for dam repairs. Cost and the owner's available funds are often key factors in how quickly repairs are scheduled.

There is no state funding to help dam owners make required repairs of their dams. "It's difficult sometimes for owners to get problems corrected because of lack of funds," Samuelson says.

After accomplishing its goal in August 2011, the program will use a risk-based method—considering each dam's classification, condition, and age—to schedule routine dam inspections.

As dams continue to age and areas develop, there is a constant need to re-evaluate some dam classifications to ensure they are still appropriate. Dam



Lake Livingston Dam
Photo courtesy of Trinity River Authority

Safety personnel use aerial photography, GIS maps from the Texas Natural Resources Information System, and Google Maps to check downstream land use. Increased development since a dam's previous classification could warrant a bump-up to a higher hazard rating.

The hiking trail at the top of the Upper Brushy Creek WCID's Dam No. 7 at Brushy Creek Lake Park in Cedar Park is popular with outdoor enthusiasts.

New Rules Support Enforcement

New state rules that went into effect at the beginning of 2009 (30 TAC, Chapter 299: "Dams and Reservoirs") improved the effectiveness of the Dam Safety Program. The rules provide the agency with more enforcement options through the courts.

"We can get an emergency order or go through the Texas Attorney General's office or district court to have a dam owner take required actions to repair the dam," Samuelson says.

The rules also changed the definition of "dam" to match the federal definition, which is:

- any artificial barrier 25 feet or higher that has a maximum impounding capacity of 15 acre-feet, or
- any artificial barrier 6 feet or higher that has a maximum impounding capacity of 50 acre-feet.

This automatically took about 400 smaller dams off the regulatory books, allowing agency staff to focus on larger dams that could have a greater impact should they fail.

"Before, our rules said a dam was anything over six feet tall," says Samuelson. "That was regardless of capacity, and included farm ponds, stock tanks, and detention ponds in neighborhoods."

Emergency Action Plans Required

In order to help prevent loss of life and property, the new state rules require owners of high- and significant-hazard dams to submit emergency action plans to the TCEQ by Jan. 1, 2011. These plans must include emergency response procedures, a list of responsible parties, a notification flow chart to clarify communications, and complete contact information for all responsible parties.

"I know there are a lot of folks working on them now," Samuelson says. "After submission to the agency, they'll need to review the plan annually to update phone numbers and they'll need to update the entire plan on a five-year frequency."

During Hurricane Rita, in 2005, the emergency action plan initiated by the Trinity River Authority for the Lake Livingston Dam called for a release of waters from the lake to help alleviate a serious problem with the stability of the dam. The lake, which is east of Huntsville in East Texas, is the second-largest reservoir in the state. During the hurricane, the dam was severely damaged by high winds and waves.

Dam Hazard Classifications

The classification system of the federal Interagency Committee on Dam Safety categorizes dams according to the amount and type of damage that could occur should the dam fail, not according to the condition of the dam.

- **High-hazard dam – loss of life is probable**
- **Significant-hazard dam – no probable loss of life, but a failure could result in economic loss, environmental damage, disruption of lifeline facilities, etc.**
- **Low-hazard dam – no probable loss of life and few economic or environmental losses other than those suffered by the dam owner**

Reclassification could occur at any time based on:

- **Inspection and downstream evaluation by the TCEQ or the dam owner's engineer**
- **Breach analysis**
- **Review of aerial photography or maps along with fieldwork**

"The authority saw the damage and initiated the emergency action plan," says Samuelson. "They notified the correct emergency management folks downstream and took action to close roads. They made major releases from the lake to get the water level down."

Program Increases Educational Efforts

The new rules cover the day-to-day operation and maintenance of dams. Each state-regulated dam must have an operation and maintenance plan, regardless of its classification. The plan must include scheduled engineering and maintenance inspections and a list of regular maintenance activities. Although owners have no set deadline to complete these plans, they must produce them if requested by the TCEQ.

The Dam Safety Program has increased its educational efforts to explain these new rules, to promote proper dam maintenance, and to emphasize the responsibilities of dam owners. Samuelson says response from dam owners has been encouraging.

"We've been able to get a lot of good information to the owners and they keep telling us to come back."

Since 2007, Samuelson has presented to more than 800 people at more than a dozen workshops around the state. The Dam Safety Program also provides guidance documents and forms on its Web site, at **www.tceq.state.tx.us/goto/dams**.

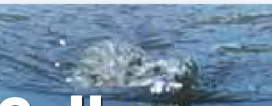
Challenges Met with Increased Awareness

Awareness about the deterioration of America's aging infrastructure—including its roads, bridges, drinking water systems, and dams—has grown, in part because of the *Report Card for America's Infrastructure*, which is issued annually by the American Society of Civil Engineers. This year, the group assigned U.S. dams a grade of D.

The Dam Safety Program's increased inspections and concentrated educational efforts are making a difference. "We have become more visible and folks know more about the program," Samuelson says. "We have people calling in and reporting situations to us. Sometimes owners who have been to a workshop and have seen something request an inspection."

Dam owners around the state are also becoming more interested in maintaining their dams and in understanding the state regulations more than ever before, says Samuelson, who has worked in the Dam Safety Program for more than 30 of his 37 years with the agency.

"We're getting a lot of response back from owners. They are trying to fix their dams. They realize their liability and responsibilities," he says. "A lot of people are paying attention to what we're saying."



Burrowing Beaver Contributes to Dam Collapse

The northeast Texas community of Edgewood received rain for a few days leading up to Thursday, March 12, 2009. That morning, rain fell again on the already damp town, and by 12:45 p.m. an earthen dam on the 25-acre private lake south of town had failed. A beaver had tunneled into the 14-foot-high earthen dam, contributing to the dam's collapse.

Water rushed through the southern parts of Edgewood, rising in lawns. The Edgewood Volunteer Fire Department reacted quickly, closing flooded FM 859. School buses were re-routed. Later, as the floodwaters receded, people were relieved to discover that no one was hurt and there was no significant property damage. The community was fortunate despite the dam's failure.

"We were scheduled to do an inspection there the following week," says Warren Samuelson, manager of the TCEQ's Dam Safety Program. "The dam's owner had seen water flowing through the dam but didn't completely understand the nature of the problem."

Texas has experienced dam failures in the past 20 years, according to Samuelson. In 2008, one dam failed, one dam's spillway failed, and one dam was overtopped. As of June of this year, in addition to the dam failure in Edgewood, the spillways of four other dams had failed. No dams had been overtopped. (Reporting is voluntary, so the actual numbers could be higher.)

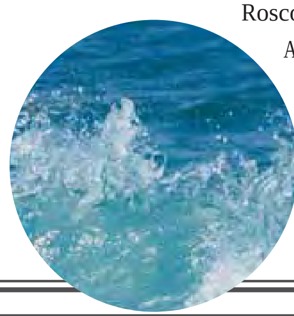
While most recent Texas dam failures have occurred in remote areas and have had relatively little impact downstream, failing dams located upstream of developed, populated areas could cause loss of life and millions of dollars in damage to property and the environment.

Environmental Excellence Takes Center Stage

Environmental awards recognize notable achievements

The Texas Environmental Excellence Awards program was created by the Texas Legislature in 1993 to recognize Texas citizens, communities, businesses, and organizations for their environmental efforts. The annual awards spotlight outstanding achievements in environmental preservation and protection in a variety of categories.

The winners of the 2009 Texas Environmental Excellence Awards were announced at the agency's Environmental Trade Fair and Conference in May.



Individual

Cliff Etheredge, Roscoe

In the small West Texas agricultural town of Roscoe, 45 miles west of Abilene, farmers have long considered the wind a nuisance because it dries out the land and kills the crops. Cliff Etheredge, however, had a vision of how to turn that nuisance into an asset.

Several years ago, Etheredge, a cotton farmer, noticed that wind turbines were springing up around Texas and wondered whether Roscoe could benefit from the burgeoning new industry of wind energy. After learning everything he could about wind energy, he was instrumental in convincing more than 350 landowners—representing nearly 100,000 acres—to get on board. He then found a developer to build a wind farm and formed the Roscoe Landowners Association to negotiate contracts and wind leases with the developer.

When completed later this year, the Roscoe Wind Farm will be the largest wind farm in the world, with 627 turbines and a total capacity of 781.5 megawatts—enough power to supply 265,000 homes.

Agriculture

Texas AgriLife Extension Service, College Station

Agricultural runoff containing nitrogen and phosphorus is one of several sources of pollution in the Arroyo Colorado, a 90-mile-long body of water that runs the length of the Rio Grande Valley. A soil testing program initiated by the Texas AgriLife Extension Service is helping to protect this important channel by reducing the amount of fertilizer that ends up in the Arroyo.

The Nutrient Management Education Program teaches growers in Cameron, Hidalgo, Starr, and Willacy counties how to collect samples for soil tests to determine how much fertilizer their soil really needs. The program also teaches proper fertilizer application and other conservation measures. To date, nitrogen fertilizer applications have been reduced by 3.3 million pounds and phosphorus fertilizer applications by 3.8 million pounds.

The growers who are putting these conservation principles into action are not only helping the environment, they are also benefiting financially, having reduced their fertilizer costs by anywhere from $9.47 an acre to more than $27 an acre.

Civic/Nonprofit

Build San Antonio Green, San Antonio

Build San Antonio Green is helping to move the practice of building green into the mainstream of San Antonio. The program certifies water- and energy-efficient homes through a quality review process. It also educates builders, remodelers, and homeowners about the benefits of green homes.

By May of this year, Build San Antonio Green had certified almost 247 new homes, representing an annual energy savings of 1.51 gigawatt-hours, which reduces nitrogen oxides by 2,492 pounds. This is the equivalent of taking 125 light-duty vehicles off the road for one year.

Build San Antonio Green was also honored on a national level this year when it received the Green Building Program of the Year award from the National Association of Home Builders.

Education

The Institute of Environmental and Human Health, Texas Tech University, Lubbock

The Institute of Environmental and Human Health (TIEHH) at Texas Tech University is ranked as one of the country's top environmental toxicology graduate programs. State-of-the-art laboratories are housed in six buildings covering more than 150,000 square feet. Researchers have partnered with almost 20 federal agencies and some of America's leading manufacturers.

An important study of Caddo Lake conducted by TIEHH aided in the cleanup of the Naval Weapons Industrial Reserve Plant, the transfer of Department of Defense property to the U.S. Fish and Wildlife Service, and the establishment of the Caddo Lake National Wildlife Refuge.

In April, TIEHH opened the Nonwovens and Advanced Materials Laboratory, where scientists are working to develop new textile materials, such as the recently patented Fibertect chemical decontamination wipe. Made from a unique nonwoven fabric, the product can absorb liquid and vapor toxicants and can be used on both people and equipment.

Government

Texas Department of Transportation

The Texas Department of Transportation has created a wide range of programs to address the state's environmental needs. Initiatives such as Bats 'N' Bridges and Don't Mess with Texas—as well as the agency's wildflower, wetlands preservation, alternative fuels, compost, and recycling programs—contribute to Texas communities with innovative approaches to conservation and beautification.

Roads are a major focus area for TxDOT. Over the past three years, the agency has reused more than 11 million tons of roadway materials. This saves landfill space and reduces emissions generated by producing and transporting new materials. To further cut emissions, the agency replaced fossil-fuel-powered engines with solar-powered ones on 250 roadway signs.

Underscoring its commitment to help drive Texas toward a cleaner future, TxDOT leads by example. More than 4,400 employees have signed up for the Clean Air Plan, the agency's internal air quality program, which includes a list of 22 actions employees can take to reduce ozone emissions. In addition, TxDOT's own fleet has more than 3,300 vehicles that use either compressed natural gas or propane.

Innovative Technology

Energy Transfer Technologies, Dallas

Moving natural gas across the state through pipelines requires significant amounts of energy, which has historically been provided by gas-fired engines. With the development of the ESelect Dual Drive, Energy Transfer Technologies is changing the way gas is delivered to market. The "dual drive" compression technology uses a combination of gas engines and electric motors to move the gas through the pipelines, drastically reducing both emissions and operating costs.

The ESelect Dual Drive allows compressors to switch between gas and electricity in response to changes in the demand for electricity. The compressors run mainly on electricity but switch to gas engines during peak demand times to help avoid the need to add generating capacity. Each 1,500 horsepower dual drive running on electricity can represent as much as a 95 percent reduction in exhaust emissions, along with reductions in noise, waste oil, and coolant usage.

Don't Miss Deadline for 2010 Awards

Deadline is October 16, 2009, for 2010 Environmental Excellence Awards

If you have been working to conserve, protect, or preserve the Texas environment, apply for the 2010 Texas Environmental Excellence Awards. The application deadline is Oct. 16, 2009.

Presented annually by the Governor of Texas and the TCEQ, the awards recognize outstanding and innovative environmental programs in 11 diverse categories:

- Agriculture
- Civic/Nonprofit
- Education
- Government
- Individual
- Innovative Technology
- Large Business, Nontechnical
- Large Business, Technical
- Small Business
- Water Conservation
- Youth

The Texas Environmental Excellence Awards are the highest distinction of environmental honor in the Lone Star State. They celebrate businesses, organizations, and individuals of all ages who are making a difference toward protecting Texas. The TCEQ will hold a banquet in Austin on May 5, 2010, to honor the award winners. Part of the Environmental Trade Fair and Conference, this celebration of environmental achievements is hosted by the TCEQ commissioners, with the special participation of Governor Rick Perry.

To download an application form or to apply online, go to www.teea.org.

Large Business, Nontechnical

Kimberly-Clark Corp., Paris

Kimberly-Clark, home to some of the world's most recognizable products for the home and personal care, takes a serious stance on environmental responsibility.

With sustainability as a core value, the K-C plant in Paris, Texas, has been working to improve the environment through energy conservation, waste reduction, and a sustainable use of natural resources. K-C recycles 99 percent of its manufacturing waste, which amounts to 23,000 tons per year. Recycled items include off-spec diapers, training pants, cardboard, metal (including soda cans), pallets, drums, trim, stretch wrap, and poly dust. For the last seven years, process water has been treated and used for landscape irrigation or has been recycled back into the process-water stream, conserving roughly 24 million gallons.

Large Business, Technical

Mars Snackfood US LLC, Waco

As a leading manufacturer of snack foods, Mars has billions of customers worldwide. Its Waco plant makes three of its major products: Snickers, Starburst, and Skittles.

Through an innovative production process, the company has found a way to lower fuel costs by using methane instead of natural gas. Two years ago, the Waco plant invested in new boiler

controls and instrumentation that would enable it to burn methane, which travels through a five-mile pipeline from the Waco Regional Landfill.

Landfill gas currently supplies nearly 50 percent of the plant's boiler fuel needs, saving the company $600,000 per year in energy costs.

Water Conservation

Boerne Independent School District, Boerne

Water is a cherished commodity to the Boerne Independent School District. An innovative rainwater harvesting system at the district's eco-friendly Champion High School is the first of its kind in the Texas public schools. Water captured from air-conditioning condensation, surface runoff, and roof runoff is stored in two elevated storage tanks and an underground stormwater pipe that is five feet in diameter and 800 feet in length.

This unique system, designed so that BISD can predict the amount of water it will need for athletic fields and landscape areas, can hold more than 224,000 gallons of water. The project has the potential of saving the school district an estimated $48,000 per year, with officials predicting that it will pay for itself in less than five years.

Champion High School also uses the collection system as part of its science curriculum, giving students valuable hands-on training in environmental stewardship.

> ***The Texas Environmental Excellence Awards program was created by the Texas Legislature in 1993 to recognize Texas citizens, communities, businesses, and organizations for their environmental efforts.***

Youth

Science Rocks U Wetlands Youth Brigade, Whiteface

In the small town of Whiteface, 45 miles west of Lubbock, an inventive group of teens is teaching the community valuable lessons about water conservation. Three years ago, as members of the Science Rocks U Wetlands Youth Brigade, the students began raising awareness about the Ogallala Aquifer and the unique wetlands that replenish it.

The Wetlands Youth Brigade calls their outreach project SPLASH, which stands for "Studying Playa Lakes and Saving Habitat." The students promote the importance of the aquifer through public seminars, school programs, festivals, brochures, and a music video.

The efforts of the group are starting to attract national attention. The students were invited to present at the U.S. Fish and Wildlife Service's first Youth Forum for the Environment. They are also currently organizing a National Wetlands Youth Brigade, and student groups from New Jersey and New Mexico have already joined.

Gregg A. Cooke Memorial Award

Richard E. Greene, Arlington

Richard E. Greene, former five-term Arlington mayor and Environmental Protection Agency Region 6 administrator, is the recipient of the 2009 Gregg A. Cooke Memorial Award for Exceptional Environmental Excellence.

As EPA regional administrator from 2003 until 2009, Greene was responsible for overseeing federal environmental programs in Arkansas, Louisiana, New Mexico, Oklahoma, and Texas. His time at the EPA was marked by tremendous challenges, which he met with strong leadership. His experience working with the different communities of the region was a valuable asset when leading the agency's response to hurricanes Katrina and Ike.

Greene is currently an adjunct professor at the School of Urban Affairs at the University of Texas at Arlington.

Gregg A. Cooke, who passed away in 2006, served as EPA Region 6 administrator from 1998 to 2003. The TCEQ created a permanent award in his name to honor his tireless efforts on behalf of the environment.

TCEQ Water Program Fees Increase

Fees secure funds for state water programs

A package of revised TCEQ rules, designed to ensure that sufficient funds are available to cover the cost of TCEQ water-program activities in the state for the 2010–2011 biennium, went into effect on July 30, 2009.

The fees affected by the rule package are the Consolidated Water Quality Fee, paid by holders of wastewater discharge permits; the Public Health Service Fee, paid by public water systems; and the Water Use Assessment Fee, paid by holders of water rights.

Why an Increase Was Necessary

General revenue appropriations to the TCEQ have declined from the $51 million received in the 2004–2005 biennium. For the 2010–2011 biennium, the 81st Legislature appropriated $9.4 million per year in general revenue to support the TCEQ's existing water programs, which is equivalent to what was appropriated for the previous biennium. This leaves the agency with an $18 million per year shortfall to fully fund its water-program activities at the appropriated amounts for the 2010–2011 biennium.

To address this shortfall, it was necessary to increase the revenues collected from water fees deposited to Water Resource Management Account 153. This account is the primary source of state funding for all of the agency's water programs. While revenue from existing fees deposited to Account 153 has remained stable, the demand for funding from the account has increased. As a result, the fund balance is almost depleted.

Account 153 supports a wide range of activities and programs, including those related to water rights, storm water, public drinking water, Total Maximum Daily Load development, water utilities, wastewater, river compacts, water-availability modeling, water assessment, concentrated animal feeding operations, sludge, the Clean Rivers Program, and groundwater protection.

The fee increases will allow the agency to maintain these activities at basically the current level.

Selection of Fees

The agency considered all of its water fees when determining how to best ensure that it could continue to carry out its water related programs beginning in fiscal year 2010.

The Consolidated Water Quality Fee, Public Health Service Fee, and Water Use Assessment Fee were selected because they are within the agency's direct authority to adjust without statutory changes; they generate a significant percentage of the revenue deposited to Account 153; their revenue stream is generally constant; and their payers constitute a broad segment of the state's population, including industry, large and small municipalities, public and private utilities, and the public, indirectly, through monthly utility bills.

The increase in the Water Use Assessment Fee will generate approximately

Payment Cycle

The payment cycle will not change under the new rule package, with payment of fees due thirty days from the billing date.

The bills will be mailed as follows:	
Public Health Service Fee:	Oct. 2009
Consolidated Water Quality Fee:	Nov. 2009
Water Use Assessment Fee:	Jan. 2010

For more information, visit www.tceq.state.tx.us/goto/waterfees.

US EPA ARCHIVE DOCUMENT

$554,000 of the amount the agency needs to address the shortfall for the 2010–2011 biennium. The increase in the Consolidated Water Quality Fee will generate an additional $3 million per year, and the increase in the Public Health Service Fee an additional $15 million per year. To generate that $15 million, the Public Health Service Fee will be assessed at $2.15 per connection per year. For the average Texan, this amounts to 18 cents per month per household.

Previous Fee Increases

The Consolidated Water Quality Fee has not been increased since it first became effective on Oct. 6, 2002.

The Public Health Service Fee was last amended in 2001 to the current flat fee or per-connection calculation. Systems paying a flat fee have not seen an increase since 2001. The formula for calculating the per-connection rate also has not changed since 2001. Fees for the public water systems that pay per connection have increased due only to system growth.

In 1992, the TCEQ began assessing a fee on holders of water rights. In 2001, this fee became known as the Water Use Assessment Fee. The last changes to the fee were implemented in 1994.

New Laws Address Agency Priorities *cont. from page 7*

Water

Senate Bill 1757

Medical Waste Disposal

To help ensure that unused pharmaceuticals do not enter a wastewater system, the TCEQ will conduct a study and submit recommendations to the Legislature regarding the methods currently used in Texas to safely handle and dispose of pharmaceuticals, medical sharps, and other potentially dangerous waste; alternative methods used for that purpose, including the methods used in other states; and the effects of the various methods on public health and the environment.

Fees

House Bill 1433

Texas Water Code Statutory Cap

The statutory cap set in the Texas Water Code for the water use assessment fee and the consolidated water quality fee has been raised from $75,000 to $100,000. The cap can be raised annually, up to a maximum of $150,000, to reflect the percentage change during the preceding year in the Consumer Price Index for All Urban Consumers.

Utilities, Districts, and Authorities

Senate Bill 361

Emergency Preparedness

In the aftermath of a natural disaster such as Hurricane Ike, the availability of drinking water and effective wastewater treatment is a concern.

SB 361 addresses that concern by requiring an affected utility to ensure the emergency operation of its water system during an extended power outage as soon as safe and practicable following the occurrence of a natural disaster. In addition, an affected utility must adopt and submit to the TCEQ for review and approval an emergency preparedness plan that demonstrates the utility's ability to provide emergency operations.

An affected utility is defined as a retail public utility, exempt utility, or provider or conveyor of potable or raw water service that furnishes water service to more than one customer in a county with a population of 3.3 million or more or in a county with a population of 400,000 or more adjacent to a county with a population of 3.3 million or more.

Agency Administration

House Bill 3544

Electronic Means of Information Transmission

The TCEQ is authorized to use electronic means of transmission for information issued or sent by the agency. The law also provides exemption from non-disclosure of e-mail addresses submitted for the purpose of providing public comment or receiving notices, orders, or decisions. If public information exists in electronic or magnetic medium, then a copy may be requested in either medium. If the information cannot be provided in the requested medium, the TCEQ will provide a copy in another medium that is acceptable to the requester.

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TCEQ Strike Team

Ready to communicate in a crisis


TCEQ photo by Cameron Lopez

By Diana Barkley,
TCEQ Agency Communications

When Hurricane Ike tore through Galveston and other Gulf Coast communities last year, the TCEQ Emergency Response Strike Team was ready for storm duty. This year, the team is again prepared to play a key role in coordinating and supporting communication systems during disasters and other emergencies.

In June, Strike Team members participated in a Department of Defense exercise at Camp Mabry in Austin. The exercise featured a mock hurricane five days before landfall. The goal: test radio interoperability and satellite communication systems among partners from local, state, and federal agencies, including the military—in the immediate local area, within Texas, and out of state.

The TCEQ team was able to connect and share radio and satellite communications with partners at three Texas sites—Austin, Midland, and the Rio Grande Valley—as well as 17 out-of-state sites. Testing the reach of the system, the team was also able to communicate with the International Space Station.

As a result of the exercise, the DoD certified the TCEQ's system, giving the agency access to the National Guard's satellite communications system.

"This provides us with a secure communications and support system with a high satellite bandwidth, which enables us to use video streaming, wireless video, and high-quality VoIP [Voice over Internet Protocol] to make phone calls through computer networks," says Kelly Crunk of the TCEQ Strike Team. "This also helps us support other agencies during an emergency situation."

§98.37 Records That Must be Retained.

In addition to the requirements of §98.3(g), you must retain the applicable records specified in §§98.34(f) and (g), 98.35(b), and 98.36(e).

§98.38 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table C-1 of Subpart C—Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Coal and Coke	**mmBtu/short ton**	**kg CO_2 /mmBtu**
Anthracite	25.09	103.54
Bituminous	24.93	93.40
Subbituminous	17.25	97.02
Lignite	14.21	96.36
Coke	24.80	102.04
Mixed (Commercial sector)	21.39	95.26
Mixed (Industrial coking)	26.28	93.65
Mixed (Industrial sector)	22.35	93.91
Mixed (Electric Power sector)	19.73	94.38
Natural Gas	**mmBtu/scf**	**kg CO_2 /mmBtu**
Pipeline (Weighted U.S. Average)	1.028×10^{-3}	53.02
Petroleum Products	**mmBtu/gallon**	**kg CO_2 /mmBtu**
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Still Gas	0.143	66.72
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73

Table C-1 of Subpart C—Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.83
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.129	70.97
Petroleum Coke	0.143	102.41
Special Naphtha	0.125	72.34
Unfinished Oils	0.139	74.49
Heavy Gas Oils	0.148	74.92
Lubricants	0.144	74.27
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22
Asphalt and Road Oil	0.158	75.36
Crude Oil	0.138	74.49
Fossil Fuel-derived Fuels (Solid)	**mmBtu/short ton**	**kg CO_2 /mmBtu**
Municipal Solid Waste[1]	9.95	90.7
Tires	26.87	85.97
Fossil Fuel-derived Fuels (Gaseous)	**mmBtu/scf**	**kg CO_2 /mmBtu**
Blast Furnace Gas	0.092×10^{-3}	274.32
Coke Oven Gas	0.599×10^{-3}	46.85
Biomass Fuels - Solid	**mmBtu/short Ton**	**kg CO_2 /mmBtu**
Wood and Wood Residuals	15.38	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	25.83	105.51
Biomass Fuels - Gaseous	**mmBtu/scf**	**kg CO_2 /mmBtu**
Biogas (Captured methane)	0.841×10^{-3}	52.07
Biomass Fuels - Liquid	**mmBtu/gallon**	**kg CO_2 /mmBtu**
Ethanol (100%)	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

[1]Allowed only for units that do not generate steam and use Tier 1.

Table C-2 of Subpart C—Default CH_4 and N_2O Emission Factors for Various Types of Fuel.

Fuel Type	Default CH_4 Emission Factor (kg CH_4 /mmBtu)	Default N_2O Emission Factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.1×10^{-2}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}

Fuel Type	Default CH_4 Emission Factor (kg CH_4 /mmBtu)	Default N_2O Emission Factor (kg N_2O/mmBtu)
Petroleum (All fuel types in Table C-1)	3.0 x 10^{-03}	6.0 x 10^{-04}
Municipal Solid Waste	3.2 x 10^{-02}	4.2 x 10^{-03}
Tires	3.2 x 10^{-02}	4.2 x 10^{-03}
Blast Furnace Gas	2.2 x 10-05	1.0 x 10^{-04}
Coke Oven Gas	4.8 x 10-04	1.0 x 10^{-04}
Biomass Fuels - Solid (All fuel types in Table C-1)	3.2 x 10^{-02}	4.2 x 10^{-03}
Biogas	3.2 x 10^{-03}	6.3 x 10^{-04}
Biomass Fuels – Liquid (All fuel types in Table C-1)	1.1 x 10^{-03}	1.1 x 10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH_4/MMBtu.

[1]Allowed only for units that do not generate steam and use Tier 1.

Table C-2 of Subpart C—Default CH_4 and N_2O Emission Factors for Various Types of Fuel.

Fuel Type	Default CH_4 Emission Factor (kg CH_4 /mmBtu)	Default N_2O Emission Factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.1 x 10^{-2}	1.6 x 10^{-03}
Natural Gas	1.0 x 10^{-03}	1.0 x 10^{-04}
Petroleum (All fuel types in Table C-1)	3.0 x 10^{-03}	6.0 x 10^{-04}
Municipal Solid Waste	3.2 x 10^{-02}	4.2 x 10^{-03}
Tires	3.2 x 10^{-02}	4.2 x 10^{-03}
Blast Furnace Gas	2.2 x 10^{-05}	1.0 x 10^{-04}
Coke Oven Gas	4.8 x 10^{-04}	1.0 x 10^{-04}
Biomass Fuels - Solid (All fuel types in Table C-1)	3.2 x 10^{-02}	4.2 x 10^{-03}
Biogas	3.2 x 10^{-03}	6.3 x 10^{-04}
Biomass Fuels – Liquid (All fuel types in Table C-1)	1.1 x 10^{-03}	1.1 x 10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH_4/MMBtu.

Subpart D—Electricity Generation

§98.40 Definition of the source category.

Facility/Compound Specific Fugitive Emission Factors

Equipment/ Service	Ethylene Oxide [1]	Phosgene [2]	Butadiene [3]	Petroleum Marketing Terminal [4]	Oil and Gas Production Operations [5]				Refinery [6]
					Gas	Heavy Oil <20° API	Light Oil >20°	Water/Light Oil	
Valves					0.00992	0.0000185	0.0055	0.000216	
Gas/Vapor	0.000444	0.00000216	0.001105	0.0000287					0.059
Light Liquid	0.00055	0.00000199	0.00314	0.0000948					0.024
Heavy Liquid				0.0000948					0.00051
Pumps	0.042651	0.0000201	0.05634		0.00529	0.00113 [10]	0.02866	0.000052	
Light Liquid				0.00119					0.251
Heavy Liquid				0.00119					0.046
Flanges/Connectors	0.000555	0.00000011	0.000307		0.00086	0.00000086	0.000243	0.000006	0.00055
Gas/Vapor				0.000092604					
Light Liquid				0.00001762					
Heavy Liquid				0.0000176					
Compressors	0.000767		0.000004		0.0194	0.0000683	0.0165	0.0309	1.399
Relief Valve	0.000165	0.0000162	0.02996		0.0194	0.0000683	0.0165	0.0309	0.35
Open-ended Lines [7]	0.001078	0.00000007	0.00012		0.00441	0.000309	0.00309	0.00055	0.0051
Sampling	0.000088		0.00012						0.033
Connectors					0.00044	0.0000165	0.000463	0.000243	
Other [9]					0.0194	0.0000683	0.0165	0.0309	
Gas/Vapor				0.000265					
Light/Heavy Liquid				0.000287					
Process Drains					0.0194	0.0000683	0.0165	0.0309	0.07

Table Notes: All factors are in units of (lb/hr)/component.

1. Monitoring must occur at a leak definition of 500 ppmv. No additional control credit can be applied to these factors. Emission factors are from EOIC Fugitive Emission Study, Summer 1988.

2. Monitoring must occur at a leak definition of 50 ppmv. No additional control credit can be applied to these factors. Emission factors are from Phosgene Panel Study, Summer 1988.

3. Monitoring must occur at a leak definition of 100 ppmv. No additional control credit can be applied to these factors. Emission factors are from Randall, J. L., et al., Radian Corporation. Fugitive Emissions from the 1,3-butadiene Production Industry: A Field Study. Final Report. Prepared for the 1,3-Butadiene Panel of the Chemical Manufacturers Association. April 1989.

4. Control credit is included in the factor; no additional control credit can be applied to these factors. Monthly AVO inspection required.

5. Factors give the total organic compound emission rate. Multiply by the weight percent of non-methane, non-ethane organics to get the VOC emission rate.

6. Factors are taken from EPA Document EPA-453/R-95-017, November 1995, Page 2-13.

7. The 28 Series quarterly LDAR programs require open-ended lines to equipped with a cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.

8. Emission factor for Sampling Connections is in terms of pounds per hour per sample taken.

9. For Petroleum Marketing Terminals"Other" includes any component excluding fittings, pumps, and valves. For Oil and Gas Production Operations, "Other" includes diaphragms, dump arms, hatches, instruments, meters, polished rods, and vents.

10. No Heavy Oil - Pump factor was derived during the API study. The factor is the SOCMI without C_2 Heavy Liquid - Pump factor with a 93% reduction credit for the physical inspection.

Control Efficiencies for TNRCC Leak Detection and Repair Programs

Equipment/Service	28M	28RCT	28VHP	28MID	28LAER	Audio/Visual/Olfactory Olfactory [1]
Valves						
Gas/Vapor	75%	97%	97%	97%	97%	97%
Light Liquid	75%	97%	97%	97%	97%	97%
Heavy Liquid [2]	0% [3]	0% [4]	0% [4]	0% [4]	0% [4]	97%
Pumps						
Light Liquid	75%	75%	85%	93%	93%	93%
Heavy Liquid [2]	0% [3]	0% [3]	0% [5]	0% [6]	0% [6]	93%
Flanges/Connectors						
Gas/Vapor [7]	30%	30%	30%	30%	75%	97%
Light Liquid [7]	30%	30%	30%	30%	75%	97%
Heavy Liquid	30%	30%	30%	30%	30%	97%
Compressors	75%	75%	85%	95%	95%	95%
Relief Valve (Gas/Vapor)	75%	97%	97%	97%	97%	97%
Open-ended Lines [8]	75%	97%	97%	97%	97%	97%
Sampling Connections	75%	97%	97%	97%	97%	97%

Notes:

1. Audio, visual, and olfactory walk-through inspections are applicable for inorganic/odorous and low vapor pressure compounds referenced in Section II.

2. Monitoring components in heavy liquid service is not required by any of the 28 Series LDAR programs. If monitored with an instrument, the applicant must demonstrate that the VOC being monitored has sufficient vapor pressure to allow the reduction.

3. No credit may be taken if the concentration at saturation is below the leak definition of the monitoring program (i.e. (0.044 psia/14.7 psia) x 10^6 = 2,993 ppmv versus leak definition = 10,000 ppmv)

4. Valves in heavy liquid service may be given a 97% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.

5. Pumps in heavy liquid service may be given an 85% reduction credit if monitored at 2,000 ppmv by permit condition provided that the concentration at saturation is greater than 2,000 ppmv.

6. Pumps in heavy liquid service may be given a 93% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.

7. If an applicant decides to monitor their connectors using an organic vapor analyzer (OVA) at the same leak definition as valves, then the applicable valve credit may be used instead of the 30%. If this option is chosen, the company shall continue to perform the weekly physical inspections in addition to the quarterly OVA monitoring.

8. The 28 Series quarterly LDAR programs require open-ended lines to equipped with a cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.

industry segment only if emission sources specified in paragraph § 98.232(c) emit 25,000 metric tons of CO_2 equivalent or more per year. Facilities must report emissions from the natural gas distribution industry segment only if emission sources specified in paragraph § 98.232(i) emit 25,000 metric tons of CO_2 equivalent or more per year.

(b) For applying the threshold defined in § 98.2(a)(2), natural gas processing facilities must also include owned or operated residue gas compression equipment.

§ 98.232 GHGs to report.

(a) You must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraph (b) through (i) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraph (j) of this section, and stationary and portable combustion emissions as applicable as specified in paragraph (k) of this section.

(b) For offshore petroleum and natural gas production, report CO_2, CH_4, and N_2O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304. Offshore platforms do not need to report portable emissions.

(c) For an onshore petroleum and natural gas production facility, report CO_2, CH_4, and N_2O emissions from only the following source types on a well pad or associated with a well pad:

(1) Natural gas pneumatic device venting.

(2) [Reserved]

(3) Natural gas driven pneumatic pump venting.

(4) Well venting for liquids unloading.

(5) Gas well venting during well completions without hydraulic fracturing.

(6) Gas well venting during well completions with hydraulic fracturing.

(7) Gas well venting during well workovers without hydraulic fracturing.

(8) Gas well venting during well workovers with hydraulic fracturing.

(9) Flare stack emissions.

(10) Storage tanks vented emissions from produced hydrocarbons.

(11) Reciprocating compressor rod packing venting.

(12) Well testing venting and flaring.

(13) Associated gas venting and flaring from produced hydrocarbons.

(14) Dehydrator vents.

(15) [Reserved]

(16) EOR injection pump blowdown.

(17) Acid gas removal vents.

(18) EOR hydrocarbon liquids dissolved CO_2.

(19) Centrifugal compressor venting.

(20) [Reserved]

(21) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps).

(22) You must use the methods in § 98.233(z) and report under this subpart the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that are located at an onshore production well pad. Stationary or portable equipment are the following equipment which are integral to the extraction, processing or movement of oil or natural gas: Well drilling and completion equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(d) For onshore natural gas processing, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Dehydrator vents.

(5) Acid gas removal vents.

(6) Flare stack emissions.

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(e) For onshore natural gas transmission compression, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Transmission storage tanks.

(4) Blowdown vent stacks.

(5) Natural gas pneumatic device venting.

(6) [Reserved]

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(f) For underground natural gas storage, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Natural gas pneumatic device venting.

(4) [Reserved]

(5) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(g) For LNG storage, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Equipment leaks from valves; pump seals; connectors; vapor recovery compressors, and other equipment leak sources.

(h) LNG import and export equipment, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Equipment leaks from valves, pump seals, connectors, vapor recovery compressors, and other equipment leak sources.

(i) For natural gas distribution, report emissions from the following sources:

(1) Above ground meters and regulators at custody transfer city gate stations, including equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. Customer meters are excluded.

(2) Above ground meters and regulators at non-custody transfer city gate stations, including station equipment leaks. Customer meters are excluded.

(3) Below ground meters and regulators and vault equipment leaks. Customer meters are excluded.

(4) Pipeline main equipment leaks.

(5) Service line equipment leaks.

(6) Report under subpart W of this part the emissions of CO_2, CH_4, and N_2O emissions from stationary fuel combustion sources following the methods in § 98.233(z).

(j) All applicable industry segments must report the CO_2, CH_4, and N_2O emissions from each flare.

(k) Report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of subpart C. Onshore petroleum and natural gas production facilities must report stationary and portable combustion emissions as specified in paragraph (c) of this section. Natural gas distribution facilities must report stationary combustion emissions as specified in paragraph (i) of this section.

(l) You must report under subpart PP of this part (Suppliers of Carbon Dioxide), CO_2 emissions captured and transferred off site by following the requirements of subpart PP.

§ 98.233 Calculating GHG emissions.

You must calculate and report the annual GHG emissions as prescribed in this section. For actual conditions, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section.

(a) *Natural gas pneumatic device venting.* Calculate CH_4 and CO_2 emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices using Equation W–1 of this section.

$$Mass_{s,i} = Count * EF * GHG_i * Conv_i * 24 * 365 \quad \text{(Eq. W-1)}$$

Where:

$Mass_{s,i}$ = Annual total mass GHG emissions in metric tons CO_2e per year at standard conditions from a natural gas pneumatic device vent, for GHG i.

Count = Total number of continuous high bleed, continuous low bleed, or intermittent bleed natural gas pneumatic devices of each type as determined in paragraph (a)(1) of this section.

EF = Population emission factors for natural gas pneumatic device venting listed in Tables W–1A, W–3, and W–4 of this subpart for onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively.

GHG_i = For onshore petroleum and natural gas production facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas; for facilities listed in § 98.230(a)(3) through (a)(8), GHG_i equals 1.

$Conv_i$ = Conversion from standard cubic feet to metric tons CO_2e; 0.000410 for CH_4, and 0.00005357 for CO_2.

24 * 365 = Conversion to yearly emissions estimate.

(1) For onshore petroleum and natural gas production, provide the total number of continuous high bleed, continuous low bleed, or intermittent bleed natural gas pneumatic devices of each type as follows:

(i) In the first calendar year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.

(ii) In the second consecutive year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.

(iii) In the third consecutive calendar year, complete the count of all pneumatic devices, including any changes to equipment counted in prior years.

(iv) For the calendar year immediately following the third consecutive calendar year, and for calendar years thereafter, facilities must update the total count of pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(2) For onshore natural gas transmission compression and underground natural gas storage, all natural gas pneumatic devices must be counted in the first year and updated every calendar year.

(b) [Reserved]

(c) *Natural gas driven pneumatic pump venting.* Calculate CH_4 and CO_2 emissions from natural gas driven pneumatic pump venting using Equation W–2 of this section. Natural gas driven pneumatic pumps covered in paragraph (e) of this section do not have to report emissions under paragraph (c) of this section.

$$Mass_{s,i} = Count * EF * GHG_i * Conv_i * 24 * 365 \quad \text{(Eq. W-2)}$$

Where:

$Mass_{s,i}$ = Annual total mass GHG emissions in metric tons CO_2e per year at standard conditions from all natural gas pneumatic pump venting, for GHG i.

Count = Total number of natural gas pneumatic pumps.

EF = Population emission factors for natural gas pneumatic pump venting listed in Tables W–1A of this subpart for onshore petroleum and natural gas production.

GHG_i = Concentration of GHG i, CH_4 or CO_2, in produced natural gas.

$Conv_i$ = Conversion from standard cubic feet to metric tons CO_2e; 0.000410 for CH_4, and 0.00005357 for CO_2.

24 * 365 = Conversion to yearly emissions estimate.

(d) *Acid gas removal (AGR) vents.* For AGR vent (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CO_2 only (not CH_4) vented directly to the atmosphere or through a flare, engine (*e.g.* permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant using any of the calculation methodologies described in paragraph (d) of this section.

(1) *Calculation Methodology 1.* If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part, you must calculate CO_2 emissions under this subpart by following the Tier 4 Calculation Methodology and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). If CEMS and/or volumetric flow rate monitor are not available, you may install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion).

(2) *Calculation Methodology 2.* If CEMS is not available, use the CO_2 composition and annual volume of vent gas to calculate emissions using Equation W–3 of this section.

$$E_{a,CO2} = V_S * Vol_{CO2} \quad \text{(Eq. W-3)}$$

Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.

V_S = Total annual volume of vent gas flowing out of the AGR unit in cubic feet per year at actual conditions as determined by flow meter using methods set forth in § 98.234(b).

Vol_{CO2} = Volume fraction of CO_2 content in vent gas out of the AGR unit as determined in (d)(6) of this section.

(3) *Calculation Methodology 3.* If using CEMS or vent meter is not an option, use the inlet or outlet gas flow rate of the acid gas removal unit to calculate emissions for CO_2 using Equation W–4 of this section.

$$E_{a,CO2} = (V + \alpha * (V * (Vol_I - Vol_O))) * (Vol_I - Vol_O) \quad \text{(Eq. W-4)}$$

Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual condition, in cubic feet per year.

V = Total annual volume of natural gas flow into or out of the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (d)(5) of this section.

α = Factor is 1 if the outlet stream flow is measured. Factor is 0 if the inlet stream flow is measured.

Vol_I = Volume fraction of CO_2 content in natural gas into the AGR unit as determined in paragraph (d)(7) of this section.

Vol_O = Volume fraction of CO_2 content in natural gas out of the AGR unit as determined in paragraph (d)(8) of this section.

(4) *Calculation Methodology 4.* Calculate emissions using any standard simulation software packages, such as AspenTech HYSYS® and API 4679 AMINECalc, that uses the Peng-Robinson equation of state, and speciates CO_2 emissions. A minimum of the following determined for typical operating conditions over the calendar year by engineering estimate and process knowledge based on best available data must be used to characterize emissions:

(i) Natural gas feed temperature, pressure, and flow rate.

(ii) Acid gas content of feed natural gas.

(iii) Acid gas content of outlet natural gas.

(iv) Unit operating hours, excluding downtime for maintenance or standby.

(v) Exit temperature of natural gas.

(vi) Solvent pressure, temperature, circulation rate, and weight.

(5) Record the gas flow rate of the inlet and outlet natural gas stream of an AGR unit using a meter according to methods set forth in § 98.234(b). If you do not have a continuous flow meter, either install a continuous flow meter or use an engineering calculation to determine the flow rate.

(6) If continuous gas analyzer is not available on the vent stack, either install a continuous gas analyzer or take quarterly gas samples from the vent gas stream to determine Vol_{CO2} according to methods set forth in § 98.234(b).

(7) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If continuous gas analyzer is not available, either install a continuous gas analyzer or take quarterly gas samples from the inlet gas stream to determine Vol_I according to methods set forth in § 98.234(b).

(8) Determine volume fraction of CO_2 content in natural gas out of the AGR unit using one of the methods specified in paragraph (d)(8) of this section.

(i) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, you may install a continuous gas analyzer.

(ii) If a continuous gas analyzer is not available or installed, quarterly gas samples may be taken from the outlet gas stream to determine Vol_O according to methods set forth in § 98.234(b).

(iii) Use sales line quality specification for CO_2 in natural gas.

(9) Calculate CO_2 volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(10) Mass CO_2 emissions shall be calculated from volumetric CO_2 emissions using calculations in paragraph (v) of this section.

(11) Determine if emissions from the AGR unit are recovered and transferred outside the facility. Adjust the emission estimated in paragraphs (d)(1) through (d)(10) of this section downward by the magnitude of emission recovered and transferred outside the facility.

(e) *Dehydrator vents.* For dehydrator vents, calculate annual CH_4, CO_2 and N_2O (when flared) emissions using calculation methodologies described in paragraphs (e)(1) or (e)(2) of this section.

(1) *Calculation Methodology 1.* Calculate annual mass emissions from dehydrator vents with throughput greater than or equal to 0.4 million standard cubic feet per day using a software program, such as AspenTech HYSYS® or GRI–GLYCalc, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. A minimum of the following parameters determined by engineering estimate based on best available data must be used to characterize emissions from dehydrators:

(i) Feed natural gas flow rate.

(ii) Feed natural gas water content.

(iii) Outlet natural gas water content.

(iv) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/electric).

(v) Absorbent circulation rate.

(vi) Absorbent type: including triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).

(vii) Use of stripping natural gas.

(viii) Use of flash tank separator (and disposition of recovered gas).

(ix) Hours operated.

(x) Wet natural gas temperature and pressure.

(xi) Wet natural gas composition. Determine this parameter by selecting one of the methods described under paragraph (e)(2)(xi) of this section.

(A) Use the wet natural gas composition as defined in paragraph (u)(2)(i) of this section.

(B) If wet natural gas composition cannot be determined using paragraph (u)(2)(i) of this section, select a representative analysis.

(C) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as specified in § 98.234(b)(1) to sample and analyze wet natural gas composition.

(D) If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) *Calculation Methodology 2.* Calculate annual CH_4 and CO_2 emissions from glycol dehydrators with throughput less than 0.4 million cubic feet per day using Equation W–5 of this section:

$$E_{s,i} = EF_i * Count * 1000 \quad \text{(Eq. W-5)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Population emission factors for glycol dehydrators in thousand standard cubic feet per dehydrator per year. Use 74.5 for CH_4 and 3.26 for CO_2 at 68°F and 14.7 psia or 73.4 for CH_4 and 3.21 for CO_2 at 60°F and 14.7 psia.

Count = Total number of glycol dehydrators with throughput less than 0.4 million cubic feet.

1000 = Conversion of EF_i in thousand standard cubic to cubic feet.

(3) Determine if dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (e)(1) or (e)(2) of this section downward by the magnitude of emissions captured.

(4) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:

(A) Use the dehydrator vent volume and gas composition as determined in paragraphs (e)(1) and (e)(2) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.

(5) Dehydrators that use desiccant shall calculate emissions from the amount of gas vented from the vessel every time it is depressurized for the desiccant refilling process using Equation W–6 of this section. Desiccant dehydrators covered in (e)(5) of this section do not have to report emissions under (i) of this section.

$$E_{s,n} = \frac{(H*D^2*P*P_2*\%G*365days/yr)}{(4*P_1*T*1,000cf/Mcf*100)} \quad \text{(Eq. W-6)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions in cubic feet.
H = Height of the dehydrator vessel (ft).
D = Inside diameter of the vessel (ft).
P_1 = Atmospheric pressure (psia).
P_2 = Pressure of the gas (psia).
P = pi (3.14).
%G = Percent of packed vessel volume that is gas.
T = Time between refilling (days).
100 = Conversion of %G to fraction.

(6) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(f) *Well venting for liquids unloadings.* Calculate CO_2 and CH_4 emissions from well venting for liquids unloading using one of the calculation methodologies described in paragraphs (f)(1), (f)(2) or (f)(3) of this section.

(1) *Calculation Methodology 1.* For one well of each unique well tubing diameter and producing horizon/formation combination in each gas producing field (see § 98.238 for the definition of Field) where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, a recording flow meter shall be installed on the vent line used to vent gas from the well (*e.g.* on the vent line off the wellhead separator or atmospheric storage tank) according to methods set forth in § 98.234(b). Calculate emissions from well venting for liquids unloading using Equation W–7 of this section.

$$E_{a,n} = \sum_h \sum_t T_{h,t} * FR_{h,t} \quad \text{(Eq. W-7)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions at actual conditions in cubic feet.
$T_{h,t}$ = Cumulative amount of time in hours of venting from all wells of the same tubing diameter (t) and producing horizon (h)/formation combination during the year.
$FR_{h,t}$ = Average flow rate in cubic feet per hour of the measured well venting for the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.

(i) Determine the well vent average flow rate as specified under paragraph (f)(1)(i) of this section.

(A) The average flow rate per hour of venting is calculated for each unique tubing diameter and producing horizon/formation combination in each producing field by averaging the recorded flow rates for the recorded time of one representative well venting to the atmosphere.

(B) This average flow rate is applied to all wells in the field that have the same tubing diameter and producing horizon/formation combination, for the number of hours of venting these wells.

(C) A new average flow rate is calculated every other calendar year for each reporting field and horizon starting the first calendar year of data collection.

(ii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2) *Calculation Methodology 2.* Calculate emissions from each well venting for liquids unloading using Equation W–8 of this section.

$$E_{a,n} = \{(0.37\times10^{-3})*CD^2*WD*SP*N_V\}+\{SFR*(HR-1.0)*Z\} \quad \text{(Eq. W-8)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions at actual conditions, in cubic feet/year.
0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).
CD = Casing diameter (inches).
WD = Well depth to first producing horizon (feet).
SP = Shut-in pressure (psia).
N_V = Number of vents per year.
SFR = Average sales flow rate of gas well in cubic feet per hour.
HR = Hours that the well was left open to the atmosphere during unloading.
1.0 = Hours for average well to blowdown casing volume at shut-in pressure.
Z = If HR is less than 1.0 then Z is equal to 0. If HR is greater than or equal to 1.0 then Z is equal to 1.

(i) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(3) *Calculation Methodology 3.* Calculate emissions from each well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W–9 of this section.

$$E_{a,n} = \{(0.37\times10^{-3})*TD^2*WD*SP*N_V\}+\{SFR*(HR-0.5)*Z\} \quad \text{(Eq. W-9)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions at actual conditions, in cubic feet/year.

0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

TD = Tubing diameter (inches).

WD = Tubing depth to plunger bumper (feet).

SP = Sales line pressure (psia).

N_V = Number of vents per year.

SFR = Average sales flow rate of gas well in cubic feet per hour.

HR = Hours that the well was left open to the atmosphere during unloading.

0.5 = Hours for average well to blowdown tubing volume at sales line pressure.

Z = If HR is less than 0.5 then Z is equal to 0. If HR is greater than or equal to 0.5 then Z is equal to 1.

(i) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(g) *Gas well venting during completions and workovers from hydraulic fracturing.* Calculate CH_4, CO_2 and N_2O (when flared) annual emissions from gas well venting during completions involving hydraulic fracturing in wells and well workovers using Equation W–10 of this section. Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric total gas emissions using calculations in paragraphs (u) and (v) of this section.

$$E_{a,n} = (T * FR) - EnF - SG \qquad \text{(Eq. W-10)}$$

Where:

$E_{a,n}$ = Annual volumetric total gas emissions in cubic feet at standard conditions from gas well venting during completions following hydraulic fracturing.

T = Cumulative amount of time in hours of all well completion venting in a field during the year reporting.

FR = Average flow rate in cubic feet per hour, under actual conditions, converted to standard conditions, as required in paragraph (g)(1) of this section.

EnF = Volume of CO_2 or N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job. If the fracture process did not inject gas into the reservoir, then EnF is 0. If injected gas is CO_2 then EnF is 0.

SG = Volume of natural gas in cubic feet at standard conditions that was recovered into a sales pipeline. If no gas was recovered for sales, SG is 0.

(1) The average flow rate for gas well venting to the atmosphere or to a flare during well completions and workovers from hydraulic fracturing shall be determined using either of the calculation methodologies described in this paragraph (g)(1) of this section.

(i) *Calculation Methodology 1.* For one well completion in each gas producing field and for one well workover in each gas producing field, a recording flow meter (digital or analog) shall be installed on the vent line, ahead of a flare if used, to measure the backflow venting event according to methods set forth in § 98.234(b).

(A) The average flow rate in cubic feet per hour of venting to the atmosphere or routed to a flare is determined from the flow recording over the period of backflow venting.

(B) The respective flow rates are applied to all well completions in the producing field and to all well workovers in the producing field for the total number of hours of venting of each of these wells.

(C) New flow rates for completions and workovers are measured every other calendar year for each reporting gas producing field and gas producing geologic horizon in each gas producing field starting in the first calendar year of data collection.

(D) Calculate total volumetric flow rate at standard conditions using calculations in paragraph (t) of this section.

(ii) *Calculation Methodology 2.* For one well completion in each gas producing field and for one well workover in each gas producing field, record the well flowing pressure upstream (and downstream in subsonic flow) of a well choke according to methods set forth in § 98.234(b) to calculate intermittent well flow rate of gas during venting to the atmosphere or a flare. Calculate emissions using Equation W–11 of this section for subsonic flow or Equation W–12 of this section for sonic flow:

$$FR = 1.27 * 10^5 * A * \sqrt{3430 * T_u * \left[\left(\frac{P_2}{P_1}\right)^{1.515} - \left(\frac{P_2}{P_1}\right)^{1.758}\right]} \qquad \text{(Eq. W-11)}$$

Where:

FR = Average flow rate in cubic feet per hour, under subsonic flow conditions.

A = Cross sectional area of orifice (m^2).

P_1 = Upstream pressure (psia).

T_u = Upstream temperature (degrees Kelvin).

P_2 = Downstream pressure (psia).

3430 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

$$FR = 1.27 * 10^5 * A * \sqrt{187.08 * T_u} \qquad \text{(Eq. W-12)}$$

Where:

FR = Average flow rate in cubic feet per hour, under sonic flow conditions.

A = Cross sectional area of orifice (m^2).

T_u = Upstream temperature (degrees Kelvin).

187.08 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

(A) The average flow rate in cubic feet per hour of venting across the choke is calculated for one well completion in each gas producing field and for one well workover in each gas producing field by averaging the gas flow rates during venting to the atmosphere or routing to a flare.

(B) The respective flow rates are applied to all well completions in the gas producing field and to all well workovers in the gas producing field for the total number of hours of venting of each of these wells.

(C) Flow rates for completions and workovers in each field shall be calculated once every two years for each reporting gas producing field and geologic horizon in each gas producing field starting in the first calendar year of data collection.

(D) Calculate total volumetric flow rate at standard conditions using calculations in paragraph (t) of this section.

(2) The volume of CO_2 or N_2 injected into the well reservoir during energized hydraulic fractures will be measured using an appropriate meter as described in 98.234(b) or using receipts of gas purchases that are used for the energized fracture job.

(i) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(3) The volume of recovered completion gas sent to a sales line will be measured using existing company records. If data does not exist on sales gas, then an appropriate meter as described in 98.234(b) may be used.

(i) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric total emissions using calculations in paragraphs (u) and (v) of this section.

(5) Determine if the well completion or workover from hydraulic fracturing recovered gas with purpose designed equipment that separates saleable gas from the backflow, and sent this gas to a sales line (*e.g.* reduced emissions completion).

(i) Use the factor SG in Equation W–10 of this section, to adjust the emissions estimated in paragraphs (g)(1) through (g)(4) of this section by the magnitude of emissions captured using reduced emission completions as determined by engineering estimate based on best available data.

(ii) [Reserved]

(6) Calculate annual emissions from gas well venting during well completions and workovers from hydraulic fracturing to flares as follows:

(i) Use the total gas well venting volume during well completions and workovers as determined in paragraph (g) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and workovers using hydraulic fracturing emissions from the flare. This adjustment to emissions from completions using flaring versus completions without flaring accounts for the conversion of CH_4 to CO_2 in the flare.

(h) *Gas well venting during completions and workovers without hydraulic fracturing.* Calculate CH_4, CO_2 and N_2O (when flared) emissions from each gas well venting during well completions and workovers not involving hydraulic fracturing and well workovers not involving hydraulic fracturing using Equation W–13 of this section:

$$E_{a,n} = N_{wo} * EF_{wo} + \sum_{f} V_f * T_f \qquad \text{(Eq. W-13)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions in cubic feet at actual conditions from gas well venting during well completions and workovers without hydraulic fracturing.

N_{wo} = Number of workovers per field not involving hydraulic fracturing in the reporting year.

EF_{wo} = Emission Factor for non-hydraulic fracture well workover venting in actual cubic feet per workover. EF_{wo} = 2,454 standard cubic feet per well workover without hydraulic fracturing.

f = Total number of well completions without hydraulic fracturing in a field.

V_f = Average daily gas production rate in cubic feet per hour of each well completion without hydraulic fracturing. This is the total annual gas production volume divided by total number of hours the wells produced to the sales line. For completed wells that have not established a production rate, you may use the average flow rate from the first 30 days of production. In the event that the well is completed less than 30 days from the end of the calendar year, the first 30 days of the production straddling the current and following calendar years shall be used.

T_f = Time each well completion without hydraulic fracturing was venting in hours during the year.

(1) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(3) Calculate annual emissions from gas well venting during well completions and workovers not involving hydraulic fracturing to flares as follows:

(i) Use the gas well venting volume during well completions and workovers as determined in paragraph (h) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and workovers emissions without hydraulic fracturing from the flare.

(i) *Blowdown vent stacks.* Calculate CO_2 and CH_4 blowdown vent stack emissions from depressurizing equipment to the atmosphere (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraph (e)(5) of this section) as follows:

(1) Calculate the total volume (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) between isolation valves determined by engineering estimate based on best available data.

(2) If the total volume between isolation valves is greater than or equal to 50 standard cubic feet, retain logs of the number of blowdowns for each equipment type (including but not limited to compressors, vessels, pipelines, headers, fractionators, and tanks). Blowdown volumes smaller than 50 standard cubic feet are exempt from reporting under paragraph (i) of this section.

(3) Calculate the total annual venting emissions for each equipment type using Equation W–14 of this section:

$$E_{s,n} = N * \left(V_v \left(\frac{(459.67 + T_s) P_a}{(459.67 + T_a) P_s} \right) - V_v * C \right) \qquad \text{(Eq. W-14)}$$

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.
N = Number of repetitive blowdowns for each equipment type of a unique volume in calendar year.
V_v = Total volume of blowdown equipment chambers (including pipelines, compressors and vessels) between isolation valves in cubic feet.
C = Purge factor that is 1 if the equipment is not purged or zero if the equipment is purged using non-GHG gases.
T_s = Temperature at standard conditions (°F).
T_a = Temperature at actual conditions in the blowdown equipment chamber (°F).
P_s = Absolute pressure at standard conditions (psia).
P_a = Absolute pressure at actual conditions in the blowdown equipment chamber (psia).

(4) Calculate both CH_4 and CO_2 mass emissions from volumetric natural gas emissions using calculations in paragraph (v) of this section.

(5) Calculate total annual venting emissions for all blowdown vent stacks by adding all standard volumetric and mass emissions determined in Equation W–14 and paragraph (i)(4) of this section.

(j) *Onshore production storage tanks.* Calculate CH_4, CO_2 and N_2O (when flared) emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage not owned or operated by the reporter), calculate annual CH_4 and CO_2 emissions using any of the calculation methodologies described in this paragraph (j).

(1) *Calculation Methodology 1.* For separators with oil throughput greater than or equal to 10 barrels per day. Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks using operating conditions in the last wellhead gas-liquid separator before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the oil from the separator enters an atmospheric pressure storage tank. A minimum of the following parameters determined for typical operating conditions over the year by engineering estimate and process knowledge based on best available data must be used to characterize emissions from liquid transferred to tanks.

(i) Separator temperature.

(ii) Separator pressure.

(iii) Sales oil or stabilized oil API gravity.

(iv) Sales oil or stabilized oil production rate.

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Separator oil composition and Reid vapor pressure. If this data is not available, determine these parameters by selecting one of the methods described under paragraph (j)(1)(viii) of this section.

(A) If separator oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your separator pressure first, and API gravity secondarily.

(B) If separator oil composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the field.

(C) Analyze a representative sample of separator oil in each field for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) *Calculation Methodology 2.* Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks for wellhead gas-liquid separators with oil throughput greater than or equal to 10 barrels per day by assuming that all of the CH_4 and CO_2 in solution at separator temperature and pressure is emitted from oil sent to storage tanks. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as described in § 98.234(b)(1) to sample and analyze separator oil composition at separator pressure and temperature.

(3) *Calculation Methodology 3.* For wells with oil production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks without passing through a wellhead separator, calculate CH_4 and CO_2 emissions by either of the methods in paragraph (j)(3) of this section:

(i) If well production oil and gas compositions are available through your previous analysis, select the latest available analysis that is representative of produced oil and gas from the field and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(ii) If well production oil and gas compositions are not available, use default oil and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match your well production gas/oil ratio and API gravity and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(4) *Calculation Methodology 4.* For wells with oil production greater than or equal to 10 barrels per day that flow to a separator not at the well pad, calculate CH_4 and CO_2 emissions by either of the methods in paragraph (j)(4) of this section:

(i) If well production oil and gas compositions are available through your previous analysis, select the latest available analysis that is representative of oil at separator pressure determined by best available data and assume all of the CH_4 and CO_2 in the oil is emitted from the tank.

(ii) If well production oil composition is not available, use default oil composition in software programs, such as API 4697 E&P Tank, that most closely match your well production API gravity and pressure in the off-well pad separator determined by best available data. Assume all of the CH_4 and CO_2 in the oil phase is emitted from the tank.

(5) *Calculation Methodology 5.* For well pad gas-liquid separators and for wells flowing off a well pad without passing through a gas-liquid separator with throughput less than 10 barrels per day use Equation W–15 of this section:

$$E_{s,i} = EF_i * Count \quad \text{(Eq. W-15)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.
EF_i = Populations emission factor for separators and wells in thousand standard cubic feet per separator or well per year, for crude oil use 4.3 for CH_4 and 2.9 for CO_2 at 68 °F and 14.7 psia, and for gas condensate use 17.8 for CH_4 and 2.9 for CO_2 at 68 °F and 14.7 psia.
Count = Total number of separators and wells with throughput less than 10 barrels per day.

(6) Determine if the storage tank receiving your separator oil has a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (j)(1) through (j)(5) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) [Reserved]

(7) Determine if the storage tank receiving your separator oil is sent to flare(s).

(i) Use your separator flash gas volume and gas composition as determined in this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine your contribution to storage tank emissions from the flare.

(8) Calculate emissions from occurrences of well pad gas-liquid separator liquid dump valves not closing during the calendar year by using Equation W–16 of this section.

$$E_{s,i} = (CF_n * E_n * T_n) + (E_t * (8760 - T_n)) \quad \text{(Eq. W-16)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each storage tank in cubic feet.

E_n = Storage tank emissions as determined in Calculation Methodologies 1, 2, or 5 in paragraphs (j)(1) through (j)(5) of this section (with wellhead separators) during time T_n in cubic feet per hour.

T_n = Total time the dump valve is not closing properly in the calendar year in hours. T_n is estimated by maintenance or operations records (records) such that when a record shows the valve to be open improperly, it is assumed the valve was open for the entire time period preceding the record starting at either the beginning of the calendar year or the previous record showing it closed properly within the calendar year. If a subsequent record shows it is closing properly, then assume from that time forward the valve closed properly until either the next record of it not closing properly or, if there is no subsequent record, the end of the calendar year.

CF_n = Correction factor for tank emissions for time period T_n is 3.87 for crude oil production. Correction factor for tank emissions for time period T_n is 5.37 for gas condensate production. Correction factor for tank emissions for time period T_n is 1.0 for periods when the dump valve is closed.

E_t = Storage tank emissions as determined in Calculation Methodologies 1, 2, or 3 in paragraphs (j)(1) through (j)(5) of this section at maintenance or operations during the time the dump valve is closing properly (ie. $8760-T_n$) in cubic feet per hour.

(9) Calculate both CH_4 and CO_2 mass emissions from volumetric natural gas emissions using calculations in paragraph (v) of this section.

(k) *Transmission storage tanks.* For condensate storage tanks, either water or hydrocarbon, without vapor recovery or thermal control devices in onshore natural gas transmission compression facilities calculate CH_4, CO_2 and N_2O (when flared) annual emissions from compressor scrubber dump valve leakage as follows:

(1) Monitor the tank vapor vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in § 98.234(a)(1) for a duration of 5 minutes. Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(2) If the tank vapors are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (k)(2) of this section to quantify emissions:

(i) Use a meter, such as a turbine meter, to estimate tank vapor volumes according to methods set forth in § 98.234(b). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapor vent stack.

(ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in § 98.234(a)(5).

(iii) Use the appropriate gas composition in paragraph (u)(2)(iii) of this section.

(3) If the leaking dump valve(s) is fixed following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired.

(4) Calculate emissions from storage tanks to flares as follows:

(i) Use the storage tank emissions volume and gas composition as determined in either paragraph (j)(1)of this section or with an acoustic leak detection device in paragraphs (k)(1) through (k)(3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine storage tank emissions from the flare.

(l) *Well testing venting and flaring.* Calculate CH_4, CO_2 and N_2O (when flared) well testing venting and flaring emissions as follows:

(1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from each well tested.

(2) If GOR cannot be determined from your available data, then you must measure quantities reported in this section according to one of the two procedures in paragraph (l)(2) of this section to determine GOR:

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) Or you may use an industry standard practice as described in § 98.234(b).

(3) Estimate venting emissions using Equation W–17 of this section.

$$E_{a,n} = GOR * FR * D \quad \text{(Eq. W-17)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from well testing in cubic feet under actual conditions.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

FR = Flow rate in barrels of oil per day for the well being tested.

D = Number of days during the year, the well is tested.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from well testing to flares as follows:

(i) Use the well testing emissions volume and gas composition as determined in paragraphs (l)(1) through (3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine well testing emissions from the flare.

(m) *Associated gas venting and flaring.* Calculate CH_4, CO_2 and N_2O (when flared) associated gas venting and flaring emissions not in conjunction with well testing (refer to paragraph (l): Well testing venting and flaring of this section) as follows:

(1) Determine the GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, the GOR from a cluster of wells in the same field shall be used.

(2) If GOR cannot be determined from your available data, then use one of the two procedures in paragraph (m)(2) of this section to determine GOR:

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) Or you may use an industry standard practice as described in § 98.234(b).

(3) Estimate venting emissions using Equation W–18 of this section.

$$E_{a,n} = GOR * V \quad \text{(Eq. W-18)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from associated gas venting under actual conditions, in cubic feet.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

V = Volume of oil produced in barrels in the calendar year during which associated gas was vented or flared.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from associated natural gas to flares as follows:

(i) Use the associated natural gas volume and gas composition as determined in paragraph (m)(1) through (4) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine associated gas emissions from the flare.

(n) *Flare stack emissions.* Calculate CO_2, CH_4, and N_2O emissions from a flare stack as follows:

(1) If you have a continuous flow measurement device on the flare, you must use the measured flow volumes to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can install a flow measuring device on the flare or use engineering calculations based on process knowledge, company records, and best available data.

(2) If you have a continuous gas composition analyzer on gas to the flare, you must use these compositions in calculating emissions. If you do not have a continuous gas composition analyzer on gas to the flare, you must use the appropriate gas compositions for each stream of hydrocarbons going to the flare as follows:

(i) For onshore natural gas production, determine natural gas composition using (u)(2)(i) of this section.

(ii) For onshore natural gas processing, when the stream going to flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer or dew point control, and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities.

(iii) When the stream going to the flare is a hydrocarbon product stream, such as ethane, propane, butane, pentane-plus and mixed light hydrocarbons, then use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(4) Calculate GHG volumetric emissions at actual conditions using Equations W–19, W–20, and W–21 of this section.

$$E_{a,CH4}(un-combusted) = V_a * (1-\eta) * X_{CH4} \quad \text{(Eq. W-19)}$$

$$E_{a,CO2}(un-combusted) = V_a * X_{CO2} \quad \text{(Eq. W-20)}$$

$$E_{a,CO2}(combusted) = \sum_j \eta * V_a * Y_j * R_j \quad \text{(Eq. W-21)}$$

Where:

E_{a,CH_4}(un-combusted) = Contribution of annual un-combusted CH_4 emissions from flare stack in cubic feet, under actual conditions.

E_{a,CO_2}(un-combusted) = Contribution of annual un-combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.

E_{a,CO_2}(combusted) = Contribution of annual combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.

V_a = Volume of gas sent to flare in cubic feet, during the year.

η = Fraction of gas combusted by a burning flare (default is 0.98). For gas sent to an unlit flare, η is zero.

X_{CH_4} = Mole fraction of CH_4 in gas to the flare.

X_{CO_2} = Mole fraction of CO_2 in gas to the flare.

Y_j = Mole fraction of gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus).

R_j = Number of carbon atoms in the gas hydrocarbon constituent j: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus).

(5) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(6) Calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(7) Calculate total annual emission from flare stacks by summing Equation W–40, Equation W–19, Equation W–20 and Equation W–21 of this section.

(8) Calculate N_2O emissions from flare stacks using Equation W–40 in paragraph (z) of this section.

(9) The flare emissions determined under paragraph (n) of this section must be corrected for flare emissions calculated and reported under other paragraphs of this section to avoid double counting of these emissions.

(o) *Centrifugal compressor venting.* Calculate CH_4, CO_2 and N_2O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents as follows:

(1) For each centrifugal compressor covered by § 98.232 (d)(2), (e)(2), (f)(2), (g)(2), and (h)(2) you must conduct an annual measurement in the operating mode in which it is found. Measure emissions from all vents (including emissions manifolded to common vents)

including wet seal oil degassing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement.

(i) Operating mode, blowdown valve leakage through the blowdown vent, wet seal and dry seal compressors.

(ii) Operating mode, wet seal oil degassing vents.

(iii) Not operating, depressurized mode, unit isolation valve leakage through open blowdown vent, without blind flanges, wet seal and dry seal compressors.

(A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(2) For wet seal oil degassing vents, determine vapor volumes sent to an atmospheric vent or flare, using a temporary meter such as a vane anemometer or permanent flow meter according to 98.234(b) of this section. If you do not have a permanent flow meter, you may install a permanent flow meter on the wet seal oil degassing tank vent.

(3) For blowdown valve leakage and unit isolation valve leakage to open ended vents, you can use one of the following methods: Calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and § 98.234(d), respectively. For through valve leakage, such as isolation valves, you may use an acoustic leak detection device according to methods set forth in § 98.234(a). If you do not have a flow meter, you may install a port for insertion of a temporary meter, or a permanent flow meter, on the vents.

(4) Estimate annual emissions using the flow measurement and Equation W–22 of this section.

$$E_{s,i,m} = MT_m * T_m * M_{i,m} * (1 - B_m) \quad \text{(Eq. W-22)}$$

Where:

$E_{s,i,m}$ = Annual GHG_i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet per hour.

T_m = Total time the compressor is in the mode for which $E_{s,i}$ is being calculated, in the calendar year in hours.

$M_{i,m}$ = Mole fraction of GHG_i in the vent gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

B_m = Fraction of operating time that the vent gas is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the time that vent gas is directed to the fuel gas system or sales.

(5) Calculate annual emissions from each centrifugal compressor using Equation W–23 of this section.

$$E_{s,i} = \sum_m EF_m * T_m * GHG_i \quad \text{(Eq. W-23)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each centrifugal compressor in cubic feet.

EF_m = Reporter emission factor for each mode m, in cubic feet per hour, from Equation W–24 of this section as calculated in paragraph 6.

T_m = Total time in hours per year the compressor was in each mode, as listed in paragraph (o)(1)(i) through (o)(1)(iii).

GHG_i = For onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG_i equals 1.

(6) You shall use the flow measurements of operating mode wet seal oil degassing vent, operating mode blowdown valve vent and not operating depressurized mode isolation valve vent for all the reporter's compressor modes not measured in the calendar year to develop the following emission factors using Equation W–24 of this section for each emission source and mode as listed in paragraph (o)(1)(i) through (o)(1)(iii).

$$EF_m = \sum \frac{MT_m}{Count_m} \quad \text{(Eq. W-24)}$$

Where:

EF_m = Reporter emission factors for compressor in the three modes m (as listed in paragraph (o)(1)(i) through (o)(1)(iii)) in cubic feet per hour.

MT_m = Flow Measurements from all centrifugal compressor vents in each mode in (o)(1)(i) through (o)(1)(iii) of this section in cubic feet per hour.

$Count_m$ = Total number of compressors measured.

m = Compressor mode as listed in paragraph (o)(1)(i) through (o)(1)(iii).

(i) The emission factors must be calculated annually. You must use all measurements from the current calendar year and the preceding two calendar years, totaling three consecutive calendar years of measurements in paragraph (o)(6) of this section.

(ii) [Reserved]

(7) Onshore petroleum and natural gas production shall calculate emissions from centrifugal compressor wet seal oil degassing vents as follows:

$$E_{s,i} = Count * EF_i \quad \text{(Eq. W-25)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from centrifugal compressor wet seals in cubic feet.

Count = Total number of centrifugal compressors for the reporter.

EF_i = Emission factor for GHG $_i$. Use 12.2 million standard cubic feet per year per compressor for CH_4 and 538 thousand standard cubic feet per year per compressor for CO_2 at 68°F and 14.7 psia or 12 million standard cubic feet per year per compressor for CH_4 and 530 thousand standard cubic feet per year per compressor for CO_2 at 60°F and 14.7 psia.

(8) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(9) Calculate emissions from seal oil degassing vent vapors to flares as follows:

(i) Use the seal oil degassing vent vapor volume and gas composition as determined in paragraphs (o)(5) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine degassing vent vapor emissions from the flare.

(p) *Reciprocating compressor venting.* Calculate CH_4 and CO_2 emissions from all reciprocating compressor vents as follows. For each reciprocating compressor covered in § 98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1) you must conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement, except as specified in paragraph (p)(9) of this section. Measure emissions from (including emissions manifolded to common vents) reciprocating rod packing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement as follows:

(1) Operating or standby pressurized mode, blowdown vent leakage through the blowdown vent stack.

(2) Operating mode, reciprocating rod packing emissions.

(3) Not operating, depressurized mode, unit isolation valve leakage through the blowdown vent stack, without blind flanges.

(i) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(ii) [Reserved]

(4) If reciprocating rod packing and blowdown vent are connected to an open-ended vent line use one of the following two methods to calculate emissions:

(i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and § 98.234(d), respectively.

(ii) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents and unit isolation valve leakage through blowdown vents according to methods set forth in § 98.234(b). If you do not have a permanent flow meter, you may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open ended vents, such as unit isolation valves on not operating, depressurized compressors and blowdown valves on pressurized compressors, you may use an acoustic detection device according to methods set forth in § 98.234(a).

(5) If reciprocating rod packing is not equipped with a vent line use the following method to calculate emissions:

(i) You must use the methods described in § 98.234(a) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or other vent with a closed distance piece.

(ii) Measure emissions found in paragraph (p)(5)(i) of this section using an appropriate meter, or calibrated bag, or high volume sampler according to methods set forth in § 98.234(b), (c), and (d), respectively.

(6) Estimate annual emissions using the flow measurement and Equation W–26 of this section.

$$E_{s,i,m} = MT_m * T_m * M_{i,m} \quad \text{(Eq. W-26)}$$

Where:

$E_{s,i,m}$ = Annual GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet per hour.

T_m = Total time the compressor is in the mode for which $E_{s,i,m}$ is being calculated, in the calendar year in hours.

$M_{i,m}$ = Mole fraction of GHG i in gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

(7) Calculate annual emissions from each reciprocating compressor using Equation W–27 of this section.

$$E_{s,i} = \sum_m EF_m * T_m * GHG_i \quad \text{(Eq. W-27)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each reciprocating compressor in cubic feet.

EF_m = Reporter emission factor for each mode, m, in cubic feet per hour, from Equation W–28 of this section as calculated in paragraph (p)(7)(i) of this section.

T_m = Total time in hours per year the compressor was in each mode, m, as listed in paragraph (p)(1) through (p)(3).

GHG_i = For onshore natural gas processing facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG_i equals 1.

m = Compressor mode as listed in paragraph (p)(1) through (p)(3).

(i) You shall use the flow meter readings from measurements of operating and standby pressurized blowdown vent, operating mode vents, not operating depressurized isolation valve vent for all the reporter's compressor modes not measured in the calendar year to develop the following emission factors using Equation W–28 of this section for each mode as listed in paragraph (p)(1) through (p)(3).

$$EF_m = \sum \frac{MT_m}{Count_m} \quad \text{(Eq. W-28)}$$

Where:

EF_m = Reporter emission factors for compressor in the three modes, m, in cubic feet per hour.

MT_m = Meter readings from all reciprocating compressor vents in each and mode, m, in cubic feet per hour.

$Count_m$ = Total number of compressors measured in each mode, m.

m = Compressor mode as listed in paragraph (p)(1) through (p)(3).

(A) You must combine emissions for blowndown vents, measured in the operating and standby pressurized modes.

(B) The emission factors must be calculated annually. You must use all measurements from the current calendar year and the preceding two calendar years, totaling three consecutive calendar years of measurements.

(ii) [Reserved]

(8) Determine if the reciprocating compressor vent vapors are sent to a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (p)(7) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) [Reserved]

(9) Onshore petroleum and natural gas production shall calculate emissions from reciprocating compressors as follows:

$$E_{s,i} = Count * EF_i \quad \text{(Eq. W-29)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from reciprocating compressors in cubic feet.

Count = Total number of reciprocating compressors for the reporter.

EF_i = Emission factor for GHG i. Use 9.63 thousand standard cubic feet per year per compressor for CH_4 and 0.535 thousand standard cubic feet per year per compressor for CO_2 at 68°F and 14.7 psia or 9.48 thousand standard cubic feet per year per compressor for CH_4 and 0.527 thousand standard cubic feet per year per compressor for CO_2 at 60°F and 14.7 psia.

(10) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (u) and (v) of this section.

(q) *Leak detection and leaker emission factors.* You must use the methods described in § 98.234(a) to conduct leak detection(s) of equipment leaks from all sources listed in § 98.232(d)(7), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1). This paragraph (q) applies to emissions sources in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (q) and do not need to be reported. If equipment leaks are detected for sources listed in this paragraph (q), calculate emissions using Equation W–30 of this section for each source with equipment leaks.

$$E_{s,i} = GHG_i * \sum_x EF_s * T_x \quad \text{(Eq. W-30)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each equipment leak source in cubic feet.

x = Total number of this type of emissions source found to be leaking during T_x.

EF_s = Leaker emission factor for specific sources listed in Table W–2 through Table W–7 of this subpart.

GHG_i = For onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2.

T_x = The total time the component was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey or the beginning of the calendar year. For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year.

(1) You must select to conduct either one leak detection survey in a calendar year or multiple complete leak detection surveys in a calendar year. The number of leak detection surveys selected must be conducted during the calendar year.

(2) Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions using calculations in paragraph (v) of this section.

(3) Onshore natural gas processing facilities shall use the appropriate default leaker emission factors listed in Table W–2 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(4) Onshore natural gas transmission compression facilities shall use the appropriate default leaker emission factors listed in Table W–3 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(5) Underground natural gas storage facilities for storage stations shall use the appropriate default leaker emission factors listed in Table W–4 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(6) LNG storage facilities shall use the appropriate default leaker emission factors listed in Table W–5 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(7) LNG import and export facilities shall use the appropriate default leaker emission factors listed in Table W–6 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(8) Natural gas distribution facilities for above ground meters and regulators at city gate stations at custody transfer, shall use the appropriate default leaker emission factors listed in Table W–7 of this subpart for equipment leak detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines.

(r) *Population count and emission factors.* This paragraph applies to emissions sources listed in § 98.232 (c)(21), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3), (i)(4) and (i)(5), on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal or less than one half inch diameter are exempt from the requirements of paragraph (r) of this section and do not need to be reported. Calculate emissions from all sources listed in this paragraph using Equation W–31 of this section.

$$E_{s,i} = Count_s * EF_s * GHG_i * T_s \quad \text{(Eq. W-31)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG emissions at standard conditions from each equipment leak source in cubic feet.

$Count_s$ = Total number of this type of emission source at the facility. Average component counts are provided by major equipment piece in Tables W–1B and Table W–1C of this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W–1D of this subpart.

EF_s = Population emission factor for the specific source, s listed in Table W–1A and Tables W–3 through Table W–7 of this subpart. Use appropriate population emission factor for operations in Eastern and Western U.S., according to Table W–1D of this subpart. EF for non-custody transfer city gate stations is determined in Equation W–32.

GHG_i = For onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2.

T_s = Total time the specific source s associated with the equipment leak emission was operational in the calendar year, in hours.

(1) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(2) Onshore petroleum and natural gas production facilities shall use the appropriate default population emission factors listed in Table W–1A of this subpart for equipment leaks from valves, connectors, open ended lines, pressure relief valves, pump, flanges, and other. Major equipment and components associated with gas wells are considered gas service components in reference to Table 1–A of this subpart and major natural gas equipment in reference to Table W–1B of this subpart. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table 1–A of this subpart and major crude oil equipment in reference to Table W–1C of this subpart. Where facilities conduct EOR operations the emissions factor listed in Table W–1A of this subpart shall be used to estimate all streams of gases, including recycle CO_2 stream. The component count can be determined using either of the methodologies described in this paragraph (r)(2). The same methodology must be used for the entire calendar year.

(i) *Component Count Methodology 1.* For all onshore petroleum and natural gas production operations in the facility perform the following activities:

(A) Count all major equipment listed in Table W–1B and Table W–1C of this subpart.

(B) Multiply major equipment counts by the average component counts listed in Table W–1B and W–1C of this subpart for onshore natural gas production and onshore oil production, respectively. Use the appropriate factor in Table W–1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W–1D of this subpart.

(ii) *Component Count Methodology 2.* Count each component individually for the facility. Use the appropriate factor in Table W–1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W–1D of this subpart.

(3) Underground natural gas storage facilities for storage wellheads shall use the appropriate default population emission factors listed in Table W–4 of this subpart for equipment leak from connectors, valves, pressure relief valves, and open ended lines.

(4) LNG storage facilities shall use the appropriate default population emission factors listed in Table W–5 of this subpart for equipment leak from vapor recovery compressors.

(5) LNG import and export facilities shall use the appropriate default population emission factor listed in Table W–6 of this subpart for equipment leak from vapor recovery compressors.

(6) Natural gas distribution facilities shall use the appropriate emission factors as described in paragraph (r)(6) of this section.

(i) Below grade meters and regulators; mains; and services, shall use the appropriate default population emission factors listed in Table W–7 of this subpart.

(ii) Above grade meters and regulators at city gate stations not at custody transfer as listed in § 98.232(i)(2), shall use the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in paragraph (q)(8) of this section to develop facility emission factors using Equation W–32 of this section. The calculated facility emission factor from Equation W–32 of this section shall be used in Equation W–31 of this section.

$$EF = \sum \frac{E_{s,i}}{Count} \quad \text{(Eq. W-32)}$$

Where:

EF = Facility emission factor for a meter at above grade M&R at city gate stations not at custody transfer in cubic feet per meter per year.

$E_{s,i}$ = Annual volumetric GHG emissions at standard condition from all equipment leak sources at all above grade M&R city gate stations at custody transfer, from paragraph (q) of this section.

Count = Total number of meter runs at all above grade M&R city gate stations at custody transfer.

(s) *Offshore petroleum and natural gas production facilities.* Report CO_2, CH_4, and N_2O emissions for offshore petroleum and natural gas production from all equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304.

(1) Offshore production facilities under BOEMRE jurisdiction shall report the same annual emissions as calculated and reported by BOEMRE in data collection and emissions estimation study published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication year, report the most recent BOEMRE reported emissions data published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS). Adjust emissions based on the operating time for the facility relative to the operating time in the most recent BOEMRE published study.

(ii) [Reserved]

(2) Offshore production facilities that are not under BOEMRE jurisdiction shall use monitoring methods and calculation methodologies published by BOEMRE referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication, report the most recent reported emissions data with emissions adjusted based on the operating time for the facility relative to operating time in the previous reporting period.

(ii) [Reserved]

(3) If BOEMRE discontinues or delays their data collection effort by more than 4 years, then offshore reporters shall once in every 4 years use the most recent BOEMRE data collection and emissions estimation methods to report emission from the facility sources.

(4) For either first or subsequent year reporting, offshore facilities either within or outside of BOEMRE jurisdiction that were not covered in the previous BOEMRE data collection cycle shall use the most recent BOEMRE data collection and emissions estimation methods published by BOEMRE referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS) to report emissions.

(t) *Volumetric emissions.* Calculate volumetric emissions at standard conditions as specified in paragraphs (t)(1) or (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions by converting actual temperature and pressure of natural gas emissions to standard temperature and pressure of natural gas using Equation W–33 of this section.

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s} \quad \text{(Eq. W-33)}$$

Where:

$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet.

$E_{a,n}$ = Natural gas volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (psia).

P_a = Absolute pressure at actual conditions (psia).

(2) Calculate GHG volumetric emissions at standard conditions by converting actual temperature and pressure of GHG emissions to standard temperature and pressure using Equation W–34 of this section.

$$E_{s,i} = \frac{E_{a,i} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s} \quad \text{(Eq. W-34)}$$

Where:

$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet.

$E_{a,i}$ = GHG i volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (psia).

P_a = Absolute pressure at actual conditions (psia).

(u) *GHG volumetric emissions.* Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (u)(1) and (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation W–35 of this section.

$$E_{s,i} = E_{s,n} * M_i \quad \text{(Eq. W-35)}$$

Where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions in cubic feet.

$E_{s,n}$ = Natural gas volumetric emissions at standard conditions in cubic feet.

M_i = Mole fraction of GHG i in the natural gas.

(2) For Equation W–35 of this section, the mole fraction, M_i, shall be the annual average mole fraction for each facility, as specified in paragraphs (u)(2)(i) through (vii) of this section.

(i) GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you must use your most recent gas composition based on available sample analysis of the field.

(ii) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in § 98.234(b).

(iii) GHG mole fraction in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.

(iv) GHG mole fraction in natural gas stored in underground natural gas storage facilities.

(v) GHG mole fraction in natural gas stored in LNG storage facilities.

(vi) GHG mole fraction in natural gas stored in LNG import and export facilities.

(vii) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.

(v) *GHG mass emissions.* Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions by converting the GHG volumetric emissions into mass emissions using Equation W–36 of this section.

$$Mass_{s,i} = E_{s,i} * \rho_i * GWP * 10^{-3} \quad \text{(Eq. W-36)}$$

Where:

$Mass_{s,i}$ = GHG i (either CH_4 or CO_2) mass emissions at standard conditions in metric tons CO_2e.

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

ρ_i = Density of GHG i. Use 0.0538 kg/ft³ for CO_2 and N_2O, and 0.0196 kg/ft³ for CH_4 at 68°F and 14.7 psia or 0.0530 kg/ft³ for CO_2 and N_2O, and 0.0193 kg/ft³ for CH_4 at 60°F and 14.7 psia.

GWP = Global warming potential, 1 for CO_2, 21 for CH_4, and 310 for N_2O.

(w) *EOR injection pump blowdown.* Calculate CO_2 pump blowdown emissions as follows:

(1) Calculate the total volume in cubic feet (including pipelines, manifolds and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns per calendar year.

(3) Calculate the total annual venting emissions using Equation W–37 of this section:

$$Mass_{c,i} = N * V_v * R_c * GHG_i * 10^{-3} \quad \text{(Eq. W-37)}$$

Where:

$Mass_{c,i}$ = Annual EOR injection gas venting emissions in metric tons at critical conditions "c" from blowdowns.

N = Number of blowdowns for the equipment in the calendar year.

V_v = Total volume in cubic feet of blowdown equipment chambers (including pipelines, manifolds and vessels) between isolation valves.

R_c = Density of critical phase EOR injection gas in kg/ft³. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice to determine density of super critical EOR injection gas.

GHG_i = Mass fraction of GHG_i in critical phase injection gas.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(x) EOR hydrocarbon liquids dissolved CO_2. Calculate dissolved CO_2 in hydrocarbon liquids produced through EOR operations as follows:

(1) Determine the amount of CO_2 retained in hydrocarbon liquids after flashing in tankage at STP conditions. Annual samples must be taken according to methods set forth in § 98.234(b) to determine retention of CO_2 in hydrocarbon liquids immediately downstream of the storage tank. Use the annual analysis for the calendar year.

(2) Estimate emissions using Equation W–38 of this section.

$$Mass_{s,CO2} = S_{hl} * V_{hl} \quad \text{(Eq. W-38)}$$

Where:

$Mass_{s,CO2}$ = Annual CO_2 emissions from CO_2 retained in hydrocarbon liquids produced through EOR operations beyond tankage, in metric tons.

S_{hl} = Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.

V_{hl} = Total volume of hydrocarbon liquids produced at the EOR operations in barrels in the calendar year.

(y) [Reserved]

(z) *Onshore petroleum and natural gas production and natural gas distribution combustion emissions.* Calculate CO_2 CH_4 and N_2O combustion-related emissions from stationary or portable equipment as follows:

(1) If the fuel combusted in the stationary or portable equipment is listed in Table C–1 of subpart C of this part, or is a blend of fuels listed in Table C–1, use the Tier 1 methodology described in subpart C of this part (General Stationary Fuel Combustion Sources). If the fuel combusted is natural gas and is pipeline quality and has a minimum high heat value of 950 Btu per standard cubic foot, then the natural gas emission factor and high heat values listed in Tables C–1 and C–2 of this part may be used.

(2) For fuel combustion units that combust field gas or process vent gas, or any blend of field gas or process vent gas and fuels listed in Table C–1 of subpart C of this part, calculate combustion emissions as follows:

(i) If you have a continuous flow meter on the combustion unit, you must use the measured flow volumes to calculate the total flow of gas to the unit. If you do not have a permanent flow meter on the combustion unit, you may install a permanent flow meter on the combustion unit, or use company records or engineering calculations based on best available data on heat duty or horsepower to estimate volumetric unit gas flow.

(ii) If you have a continuous gas composition analyzer on fuel to the combustion unit, you must use these compositions for determining the concentration of gas hydrocarbon constituent in the flow of gas to the unit. If you do not have a continuous gas composition analyzer on gas to the combustion unit, you must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit as specified in paragraph (u)(2)(i) of this section.

(iii) Calculate GHG volumetric emissions at actual conditions using Equations W–39 of this section.

$$E_{a,CO2} = \sum_j V_a * Y_j * R_j \quad \text{(Eq. W-39)}$$

Where:

E_{a,CO_2} = Contribution of annual emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

V_a = Volume of gas sent to combustion unit in cubic feet, during the year.

Y_j = Concentration of gas hydrocarbon constituents *j* (such as methane, ethane, propane, butane, and pentanes plus).

R_j = Number of carbon atoms in the gas hydrocarbon constituent *j;* 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

(3) External fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr do not need to report combustion emissions. You must report the type and number of each external fuel combustion unit.

(4) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both combustion-related CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(6) Calculate N_2O mass emissions using Equation W–40 of this section.

$$N_2O = (1 \times 10^3) \times Fuel \times HHV \times EF \quad \text{(Eq. W-40)}$$

Where:

N_2O = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).

HHV = High heat value of the fuel from paragraphs (z)(8)(i), (z)(8)(ii) or (z)(8)(iii) of this section (units must be consistent with Fuel).

EF = Use 1.0×10^{-4} kg N_2O/mmBtu.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(i) For fuels listed in Table C–1 of subpart C of this part, use the provided default HHV in the table.

(ii) For field gas or process vent gas, use 1.235×10^{-3} mmBtu/scf for HHV.

(iii) For fuels not listed in Table C–1 of subpart C of this part and not field gas or process vent gas, you must use the methodology set forth in the Tier 2 methodology described in subpart C of this part to determine HHV.

§ 98.234 Monitoring and QA/QC requirements.

The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable as specified in this section. Offshore petroleum and natural gas production facilities shall adhere to the monitoring and QA/QC requirements as set forth in 30 CFR 250.

(a) You must use any of the methods described as follows in this paragraph to conduct leak detection(s) of equipment leaks and through-valve leakage from all source types listed in § 98.233(k), (o), (p) and (q) that occur during a calendar year, except as provided in paragraph (a)(4) of this section.

(1) *Optical gas imaging instrument.* Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR part 60, subpart A, § 60.18(i)(1) and (2) of the *Alternative work practice for monitoring equipment leaks.* Any emissions detected by the optical gas imaging instrument is a leak unless screened with Method 21 (40 CFR part 60, appendix A–7) monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the optical gas imaging instrument to image the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(2) *Method 21.* Use the equipment leak detection methods in 40 CFR part 60, appendix A–7, Method 21. If using Method 21 monitoring, if an instrument reading of 10,000 ppm or greater is measured, a leak is detected. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. Owners or operators must use alternative leak detection devices as described in paragraph(a)(1) of this section to monitor inaccessible equipment leaks or vented emissions.

(3) *Infrared laser beam illuminated instrument.* Use an infrared laser beam illuminated instrument for equipment leak detection. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with Method 21 monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the infrared laser beam illuminated instrument to detect the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(4) *Optical gas imaging instrument.* An optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(5) *Acoustic leak detection device.* Use the acoustic leak detection device to detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, you must use the instrument manufacturer's calculation methods to quantify the through-valve leak. When using the acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, you must operate the acoustic leak detection device to monitor the source valves required by this subpart in accordance with the instrument manufacturer's operating parameters.

(b) You must operate and calibrate all flow meters, composition analyzers and pressure gauges used to measure quantities reported in § 98.233 according to the procedures in § 98.3(i) and the procedures in paragraph (b) of this section. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures such that it is safe to handle and can capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed for measurement.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in § 98.233(t).

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(u) and (v).

(d) Use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following manufacturer instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a high volume sampler, including positioning the instrument for complete capture of the equipment leak without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(3) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(u) and (v).

Process Streams Report Stream: Inlet Bases Grouped by Columns			
Client Name:	ETC Texas Pipeline, Ltd	Job:	
Location:	Jackson County Gas Plant	Modified: 9:50 AM, 11/11/2011	
Flowsheet:	Inlet	Status: Solved 9:50 AM, 11/11/2011	

Connections	
From: --	To: SAT-1

Composition

Total

	Mole Fraction		Mass Flow	
	%		lb/h	
Nitrogen	6.60E-02	*	406.008	
Hydrogen Sulfide	0.00E+00	*	0.00E+00	
Carbon Dioxide	1.085	*	10485.8	
Methane	76.815	*	270609	
Ethane	13.278	*	87675.2	
Propane	5.258	*	50914.4	
i-Butane	1.067	*	13618.6	
n-Butane	1.383	*	17651.8	
i-Pentane	0.396	*	6274.06	
n-Pentane	0.277	*	4388.68	
n-Hexane	0.239	*	4522.78	
Heptane	0.06	*	1320.24	
Octane	0.042	*	1053.53	
Benzene	0.01	*	171.531	
Toluene	0.015	*	303.499	
Ethylbenzene	0.001	*	23.3134	
m-Xylene	0.004	*	93.2537	
o-Xylene	0.001	*	23.3134	
p-Xylene	0.003	*	69.9403	
Water	0	*	0	
DEA	0	*	0	
MDEA	0	*	0	
TEG	0	*	0	

Vapor

	Mole Fraction		Mass Flow	
	%		lb/h	
Nitrogen	6.64E-02		405.757	
Hydrogen Sulfide	0.00E+00		0.00E+00	
Carbon Dioxide	1.08795		10449.2	
Methane	77.1681		270172	
Ethane	13.2693		87075.9	
Propane	5.19604		50003.3	
i-Butane	1.03437		13120.5	
n-Butane	1.32384		16792.2	
i-Pentane	0.36182		5697.09	
n-Pentane	0.247309		3894.03	
n-Hexane	0.178427		3355.63	
Heptane	0.0338429		740.072	
Octane	0.0147524		367.763	
Benzene	0.00750244		127.894	
Toluene	0.00775474		155.933	
Ethylbenzene	0.000314172		7.27913	
m-Xylene	0.00114112		26.4389	
o-Xylene	0.000266759		6.1806	
p-Xylene	0.000878315		20.3499	
Water	0		0	
DEA	0		0	
MDEA	0		0	
TEG	0		0	

		Process Streams Report **Stream: Inlet** **Bases Grouped by Columns**		
Client Name:	ETC Texas Pipeline, Ltd		Job:	
Location:	Jackson County Gas Plant		Modified: 9:50 AM, 11/11/2011	
Flowsheet:	Inlet		Status: Solved 9:50 AM, 11/11/2011	

Light Liquid

	Mole Fraction		Mass Flow	
	%		lb/h	
Nitrogen	0.0066001		0.251066	
Carbon Dioxide	0.611624		36.5512	
Methane	20.0599		436.99	
Ethane	14.6784		599.336	
Propane	15.2155		911.071	
i-Butane	6.31062		498.063	
n-Butane	10.8918		859.63	
i-Pentane	5.88924		576.977	
n-Pentane	5.04884		494.642	
n-Hexane	9.97408		1167.15	
Heptane	4.26388		580.165	
Octane	4.42113		685.771	
Benzene	0.411399		43.6366	
Toluene	1.17943		147.565	
Ethylbenzene	0.111224		16.0343	
m-Xylene	0.463469		66.8148	
o-Xylene	0.118844		17.1328	
p-Xylene	0.343989		49.5904	
Water	0		0	
DEA	0		0	
MDEA	0		0	
TEG	0		0	

Properties

Property	Units	Total		Vapor	Light Liquid
Temperature	°F	70	*	70	70
Pressure	psig	690	*	690	690
Mole Fraction Vapor	%	99.3816		100	0
Mole Fraction Light Liquid	%	0.618367		0	100
Mole Fraction Heavy Liquid	%	0		0	0
Molecular Weight	lb/lbmol	21.3849		21.1886	52.9297
Mass Density	lb/ft^3	3.26151		3.21615	35.2208
Molar Flow	lbmol/h	21959.6		21823.8	135.791
Mass Flow	lb/h	469605		462417	7187.37
Std Vapor Volumetric Flow	MMSCFD	200	*	198.763	1.23673
Std Liquid Volumetric Flow	sgpm	2688.08		2662.08	26.0002
Compressibility		0.812871		0.81677	0.186308
Specific Gravity				0.731586	0.564716
API Gravity					115.902
Net Ideal Gas Heating Value	Btu/ft^3	1151.28		1141.5	2724.17
Net Liquid Heating Value	Btu/lb	20366.2		20381.5	19381.9
Gross Ideal Gas Heating Value	Btu/ft^3	1268.68		1258.21	2951.24
Gross Liquid Heating Value	Btu/lb	22449.4		22471.8	21009.9

	Process Streams Report **Stream: Waste Gas from Amine Gas Treater** **Bases Grouped by Columns**	
Client Name:	ETC Texas Pipeline, Ltd	
Location:	Jackson County Gas Plant	
Flowsheet:	Inlet Treater	Status: Solved 9:50 AM, 11/11/2011

Connections	
From: Condenser	To: --

Composition		
Total		
	Mole Fraction **%**	**Mass Flow** **lb/h**
Nitrogen	2.27E-05	0.00121515
Hydrogen Sulfide	0.000252559	0.0164737
Carbon Dioxide	92.2837	7772.99
Methane	0.367783	11.2922
Ethane	0.187668	10.8001
Propane	0.0455508	3.84422
i-Butane	0.00508564	0.565723
n-Butane	0.0132735	1.47653
i-Pentane	0.00123204	0.170125
n-Pentane	0.00128787	0.177835
n-Hexane	0.000840374	0.138603
Heptane	4.48E-05	0.00859133
Octane	2.25E-05	0.00491286
Benzene	0.0306478	4.58177
Toluene	0.0358188	6.31639
Ethylbenzene	0.00113974	0.231581
m-Xylene	0.00594175	1.20729
o-Xylene	0.00139144	0.282725
p-Xylene	0.0045724	0.929056
Water	7.01375	241.829
DEA	1.49E-17	2.99E-15
MDEA	2.22E-13	5.07E-11

Vapor		
	Mole Fraction %	Mass Flow lb/h
Nitrogen	2.27E-05	0.00121515
Hydrogen Sulfide	0.000252559	0.0164737
Carbon Dioxide	92.2837	7772.99
Methane	0.367783	11.2922
Ethane	0.187668	10.8001
Propane	0.0455508	3.84422
i-Butane	0.00508564	0.565723
n-Butane	0.0132735	1.47653
i-Pentane	0.00123204	0.170125
n-Pentane	0.00128787	0.177835
n-Hexane	0.000840374	0.138603
Heptane	4.48E-05	0.00859133
Octane	2.25E-05	0.00491286
Benzene	0.0306478	4.58177
Toluene	0.0358188	6.31639
Ethylbenzene	0.00113974	0.231581
m-Xylene	0.00594175	1.20729
o-Xylene	0.00139144	0.282725
p-Xylene	0.0045724	0.929056
Water	7.01375	241.829
DEA	1.49E-17	2.99E-15
MDEA	2.22E-13	5.07E-11

Properties			
Property	Units	Total	Vapor
Temperature	°F	120	120
Pressure	psig	9.77778	9.77778
Mole Fraction Vapor	%	100	100
Mole Fraction Light Liquid	%	0	0
Mole Fraction Heavy Liquid	%	0	0
Molecular Weight	lb/lbmol	42.0968	42.0968
Mass Density	lb/ft^3	0.166903	0.166903
Molar Flow	lbmol/h	191.389	191.389
Mass Flow	lb/h	8056.86	8056.86
Std Vapor Volumetric Flow	MMSCFD	1.7431	1.7431
Std Liquid Volumetric Flow	sgpm	19.6894	19.6894
Compressibility		0.992293	0.992293
Specific Gravity		1.45349	1.45349
Net Ideal Gas Heating Value	Btu/ft^3	11.4032	11.4032
Net Liquid Heating Value	Btu/lb	-1.81617	-1.81617
Gross Ideal Gas Heating Value	Btu/ft^3	15.8845	15.8845
Gross Liquid Heating Value	Btu/lb	38.5809	38.5809

	Process Streams Report **Stream: Waste Gas from Product Treater** Bases Grouped by Columns	
Client Name:	ETC Texas Pipeline, Ltd	
Location:	Jackson County Gas Plant	
Flowsheet:	Product Treater	Status: Solved 9:51 AM, 11/11/2011

Connections	
From: Condenser	To: --

Composition		
Total		
	Mole Fraction %	Mass Flow lb/h
Nitrogen	0	0
Hydrogen Sulfide	0.0274036	0.208812
Carbon Dioxide	91.3002	898.37
Methane	0.0197926	0.0709924
Ethane	1.43948	9.67749
Propane	0.154263	1.52088
i-Butane	0.00870981	0.113185
n-Butane	0.0183011	0.237824
n-Pentane	0.0010792	0.0174087
i-Pentane	0.00134396	0.0216797
n-Hexane	0.000347176	0.00668913
Heptane	1.60E-05	0.000358333
Octane	3.22E-06	8.23E-05
Benzene	0.0106992	0.186856
Toluene	0.00648307	0.133554
Ethylbenzene	0.000100379	0.00238266
m-Xylene	0.000489402	0.0116167
o-Xylene	9.86E-05	0.00234104
p-Xylene	0.000388944	0.00923221
DEA	1.12E-16	2.62E-15
MDEA	5.30E-14	1.41E-12
Water	7.01075	28.2386
TEG	0	0

Vapor		
	Mole Fraction %	Mass Flow lb/h
Nitrogen	0	0
Carbon Dioxide	91.3002	898.37
Methane	0.0197926	0.0709924
Ethane	1.43948	9.67749
Propane	0.154263	1.52088
i-Butane	0.00870981	0.113185
n-Butane	0.0183011	0.237824
n-Pentane	0.0010792	0.0174087
i-Pentane	0.00134396	0.0216797
n-Hexane	0.000347176	0.00668913
Heptane	1.60E-05	0.000358333
Octane	3.22E-06	8.23E-05
Benzene	0.0106992	0.186856
Toluene	0.00648307	0.133554
Ethylbenzene	0.000100379	0.00238266
m-Xylene	0.000489402	0.0116167
o-Xylene	9.86E-05	0.00234104
p-Xylene	0.000388944	0.00923221
DEA	1.12E-16	2.62E-15
MDEA	5.30E-14	1.41E-12
Water	7.01075	28.2386
TEG	0	0

Properties			
Property	**Units**	**Total**	**Vapor**
Temperature	°F	120	120
Pressure	psig	9.77778	9.77778
Mole Fraction Vapor	%	100	100
Mole Fraction Light Liquid	%	0	0
Mole Fraction Heavy Liquid	%	0	0
Molecular Weight	lb/lbmol	41.9904	41.9904
Mass Density	lb/ft^3	0.166346	0.166346
Molar Flow	lbmol/h	22.3582	22.3582
Mass Flow	lb/h	938.83	938.83
Std Vapor Volumetric Flow	MMSCFD	0.20363	0.20363
Std Liquid Volumetric Flow	sgpm	2.31761	2.31761
Compressibility		0.993099	0.993099
Specific Gravity		1.44981	1.44981
Net Ideal Gas Heating Value	Btu/ft^3	28.8502	28.8502
Net Liquid Heating Value	Btu/lb	155.293	155.293
Gross Ideal Gas Heating Value	Btu/ft^3	34.999	34.999
Gross Liquid Heating Value	Btu/lb	210.862	210.862

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	Process Streams Report **Stream: Dehy Still Vent** Bases Grouped by Columns	
Client Name:	ETC Texas Pipeline, Ltd	
Location:	Jackson County Gas Plant	
Flowsheet:	Inlet Dehy	Status: Solved 9:31 AM, 11/11/2011

Connections	
From: Condenser	To: --

Composition		
Total		
	Mole Fraction %	Mass Flow lb/h
Nitrogen	3.32E-05	0.000394996
Hydrogen Sulfide	3.53E-07	5.12E-06
Carbon Dioxide	0.112105	2.0971
Methane	0.512283	3.49324
Ethane	0.768925	9.82767
Propane	0.820877	15.3858
i-Butane	0.222076	5.48645
n-Butane	0.51107	12.6261
i-Pentane	0.256159	7.85571
n-Pentane	0.2268	6.95537
n-Hexane	0.295445	10.822
Heptane	0.103217	4.39617
Octane	0.0687018	3.33572
Benzene	0.351937	11.685
Toluene	0.531189	20.8035
Ethylbenzene	0.0265323	1.1973
m-Xylene	0.102757	4.63701
o-Xylene	0.0317095	1.43093
p-Xylene	0.0741129	3.34443
Water	94.984	727.342
TEG	8.36E-05	0.00533887
DEA	0	0
MDEA	0	0

Vapor		
	Mole Fraction %	Mass Flow lb/h
Nitrogen	3.32E-05	0.000394996
Carbon Dioxide	0.112105	2.0971
Methane	0.512283	3.49324
Ethane	0.768925	9.82767
Propane	0.820877	15.3858
i-Butane	0.222076	5.48645
n-Butane	0.51107	12.6261
i-Pentane	0.256159	7.85571
n-Pentane	0.2268	6.95537
n-Hexane	0.295445	10.822
Heptane	0.103217	4.39617
Octane	0.0687018	3.33572
Benzene	0.351937	11.685
Toluene	0.531189	20.8035
Ethylbenzene	0.0265323	1.1973
m-Xylene	0.102757	4.63701
o-Xylene	0.0317095	1.43093
p-Xylene	0.0741129	3.34443
Water	94.984	727.342
TEG	8.36E-05	0.00533887
DEA	0	0
MDEA	0	0

Properties			
Property	Units	Total	Vapor
Temperature	°F	209.58	209.58
Pressure	psig	0.00405122	0.00405122
Mole Fraction Vapor	%	100	100
Mole Fraction Light Liquid	%	0	0
Mole Fraction Heavy Liquid	%	0	0
Molecular Weight	lb/lbmol	20.0615	20.0615
Mass Density	lb/ft^3	0.0413969	0.0413969
Molar Flow	lbmol/h	42.5057	42.5057
Mass Flow	lb/h	852.727	852.727
Std Vapor Volumetric Flow	MMSCFD	0.387126	0.387126
Std Liquid Volumetric Flow	sgpm	1.86135	1.86135
Compressibility		0.991882	0.991882
Specific Gravity		0.692668	0.692668
Net Ideal Gas Heating Value	Btu/ft^3	145.302	145.302
Net Liquid Heating Value	Btu/lb	1821.03	1821.03
Gross Ideal Gas Heating Value	Btu/ft^3	203.673	203.673
Gross Liquid Heating Value	Btu/lb	2925.17	2925.17