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20 July 2012

Mr. Carl E. Eglund, P.E.
Director, Multimedia Planning and Permitting Division
U.S. Environmental Protection Agency, (6PD-R)
1445 Ross Ave
Dallas, TX 75202-2733

ATKINS Project No. 044167600

RE: Response to Request for Information – Application Completeness Determination
Application for Prevention of Significant Deterioration (PSD) Permit for Greenhouse Gas Emissions – Liquefaction Plant and Pretreatment Facility
Freeport LNG Development, L.P., Brazoria County, Texas

Dear Mr. Robinson:

On behalf of Freeport LNG Development, L.P., (Freeport LNG), I am submitting the enclosed response to the request for information received from the U.S. Environmental Protection Agency (EPA) relating to the referenced application for a Greenhouse Gas PSD permit for Freeport LNG's proposed Liquefaction Project. As shown in the attached document, each comment received is listed followed by a response.

I hope this information will allow you to continue your review of this application. I will contact your staff soon after submittal of this information to discuss the attached information.

Thank you for your consideration. Should you have any questions regarding this updated information, please contact Mr. Mark Mallett, P.E., Freeport LNG Development, L.P., at (713) 333-4271 or me at (512) 342-3395 or by email: Ruben.Velasquez@atkinsglobal.com.

Sincerely,

Ruben I. Velasquez

Ruben I. Velasquez, P.E.
Senior Engineer - Air Quality
Atkins North America, Inc.

STATE OF TEXAS
RUBEN I. VELASQUEZ
69126
REGISTERED
PROFESSIONAL ENGINEER
7-20-2012

ATKINS
TBPE REG. #F-474

Enclosures

cc: Mr. Mike Wilson, Director, Air Permits Division, TCEQ
Mr. Mark Mallett, P.E., Vice-President, Freeport LNG Development, L.P

Response to EPA Request for Additional Information
Application for Greenhouse Gas Prevention of Significant Deterioration Permit
Proposed Liquefaction Project
Freeport LNG Development, L.P., Brazoria County, Texas

1. ***The application includes potential BACT Limits for the liquefaction project in Table 10-1. Also, later in the BACT analysis, the applicant proposes to limit the frequency of start-up and shut-down events to twice a year. Do the proposed BACT limits include all operating scenarios? Please provide additional information to clarify.***

Response:

Emissions from routine and planned maintenance, shutdown, startup (MSS) activities are represented and included in the proposed BACT limits and emissions summary. The proposed BACT limits shown on Table 10-1 include emissions from the anticipated facility operations and MSS activities, as summarized below:

- **Liquefaction Plant Flare (EPN: LIQFLARE)** – The Liquefaction Plant Flare will have one GHG emission limit, which includes GHG emissions from the continuous combustion of natural gas in twenty-two flare pilots and emissions estimated for a planned maintenance, shutdown, startup (MSS) event on one Liquefaction Train on a yearly basis. The Liquefaction Plant Flare will be a non-assisted type ground flare designed to combust elevated quantities of gas from the Liquefaction Plant during an emergency (i.e. fire or emergency plant shutdown). Emissions from emergency events are not included in the proposed GHG BACT limits since they are non-routine emissions.

  The flare is also used to control the emissions resulting from planned MSS activities from the Liquefaction Plant. A startup of the Liquefaction Plant would occur after a typical shutdown for compressor maintenance. One start-up of each train per year is assumed for calculation purposes. For estimation of MSS emissions, it was assumed a Liquefaction Plant shut-down will occur when the refrigeration circuits are de-inventoried; a process typically associated with maintenance and repair of compressor or drive systems. One shut-down per year is assumed for calculation purposes. See Appendix A for details of the flare emission calculations.

- **Emergency Generator and Firewater Pump Engines (EPNs: LIQEG-1, LIQEG-2, LIQEG-3, and LIQEG-4; PTFEG-1, PTFEG-2, PTFEG-3, and PTFEG-4; LFWP-1 and LFWP-2; and PTFFWP)** – Each engine will have one GHG emission limit which is based on emissions estimated for a startup and shutdown for planned testing or maintenance. Each engine would be limited to 100 hours per year operation for purposes of testing and maintenance of the engine. GHG emissions from each engine are anticipated to be directly proportional to the amount of fuel fired so these emissions would increase or decrease dependent on fuel flow to the engine. The emissions estimate for the proposed engines is based on the maximum heat input capacity of each engine operating up to 100 hours per year for purposes of testing and maintenance. Thus, the GHG emissions during startup, normal operation, or shutdown would not exceed the maximum estimated emissions shown in Appendix A.

  Emissions from operation of an emergency engine during an emergency event are not included in the proposed GHG limits since these emissions events are not routine emissions, and are therefore will not be included in the permit. A more detailed description is provided in Section 5.3 of the GHG permit application.

- **NGL Flare (EPN: NGLFLARE)** - The NGL Flare will have one GHG emission limit, which includes GHG emissions from continuous combustion of natural gas in two flare pilots and GHG emissions from planned MSS events. The NGL Flare is an elevated flare used to destroy off-gas produced from the NGL recovery system during emergency conditions and during planned MSS activities. Emissions from emergency events are not included in the GHG BACT limitation since they are non-routine.

  The NGL removal unit will be a closed loop system; i.e., no routine vent gas emissions. Should it become necessary to conduct maintenance on the NGL removal unit, the section to be brought down for maintenance will be blocked off and liquids drained back into the system to the maximum extent possible. Any residual liquids will be routed through a knock-out pot to the NGL flare for emissions control. Should there be emissions during startup of the NGL removal unit; these emissions will be routed to the NGL flare for emissions control. These planned MSS events would typically be short term events not expected to occur more than eight hours/year. See Appendix A for details of the flare emission calculations.

- **Amine Unit/Thermal Oxidizers (EPNs: TO1, TO2, and TO3)** – The Amine Unit/Thermal Oxidizers will have a GHG emission limit for each unit which includes GHG emissions from a gas-fired burner and the CO_2 emissions released from the amine units. Each Regenerative Thermal Oxidizer (RTO) will be equipped with a low-NO_X gas-fired burner that typically will only be used for initial unit start-up (cold-start) and to maintain the proper combustion zone temperature.

  Due to the abundant oxygen content of the process gas, complete combustion readily occurs when the ignition point is reached in the oxidizer. Once the burner heats the RTO to operating temperature and if the waste gas from the amine regeneration units contains enough thermal energy to sustain temperature in the combustion zone, the burner will shut off. BOG or natural gas will be fired, as necessary, to supplement the combustion heat requirements of the RTO and maintain the proper combustion temperature.

  Before startup of the amine treatment unit, the RTOs will be started and brought to operating temperature. As the incoming natural gas stream is introduced to each train, the vent gas from the amine unit will flow to the RTOs for emissions control. Emissions from the shutdown of the amine unit will also be routed to the RTOs. GHG emissions from each RTO are anticipated to be directly proportional to the waste gas stream from the amine treatment units. The emissions estimate for the RTOs is based on the maximum anticipated waste stream rate to the RTOs, thus, the GHG emissions during startup, normal operation, or shutdown of the amine treatment units are included in and will not exceed the emissions summary for the RTOs as shown in Appendix A.

- **Combustion Turbine (EPN: CT1(A)/CT1(B))** – The Pretreatment Facility will include one General Electric (GE) Frame 7EA simple cycle, natural gas-fired, combustion turbine (CT) exhausting to a heat exchanger for waste heat recovery. The CT will have a nominal base-load gross electric power output of approximately 87 megawatts. The CT will normally operate at base load; transferring waste heat to hot oil in the waste heat recovery unit for use in the amine treatment units. The hot oil will be used in the amine sweetening units and dehydration system units in lieu of burning natural gas fuel in these units.

The Combustion Turbine will have a GHG emission limit which includes GHG emissions from continuous combustion of fuel gas during normal operation and during planned MSS events. GHG emissions from the turbine are anticipated to be directly proportional to the amount of fuel fired in the turbine combustor so these emissions would increase or decrease dependent on gas flow to the turbine. It is anticipated that there would be two planned startup and shutdown events for tuning and maintenance purposes during a calendar year. However, for purposes of estimating emissions to establish the BACT limit, it was conservatively assumed combustion turbine would fire fuel, at maximum input capacity, on continuous year round basis. Thus, the GHG emissions during startup, normal operation, or shutdown would not exceed the maximum estimated emissions for the combustion turbine as shown in Appendix A.

- **Heating Medium Heaters (EPNs: 65B-81A, 65B-81B, 65B-81C, 65B-81D, 65B-81E, 65B-81F, 65B-81G, 65B-81H, 65B-81I, 65B-81J)** – The amine treatment trains will be supported by ten (10) heating medium heaters. As previously discussed, recovery of energy from the CT exhaust gas will not be sufficient to meet all of the energy supply requirements for all three pretreatment trains. Additional energy will be provided to the system by the ten (10) stand-alone (gas-fired) heating medium heaters in order to fully meet heating demands. Only two (2) of these heaters will be required to meet system energy demands when the CT is operating. The remaining eight (8) heaters will be provided as backup to the CT when the turbine and waste heat recovery system is not in operation.

  It is anticipated that for the CT, there would be two planned startup and shutdown events for tuning and maintenance purposes during a calendar year. The duration of each planned tuning and maintenance event is 7 days; 14 days for the two annual events. During this time period, it is anticipated that the full complement of the ten (10) heating medium heaters would be used; each firing natural gas. The proposed GHG BACT limit is for all 10 units combined, inclusive of operation of the equivalent of two heaters on a continuous basis and all the heaters during the two week time period when the CT is down for tuning and maintenance.

GHG emissions from the heating medium heaters are anticipated to be directly proportional to the amount of fuel fired so these emissions would increase or decrease dependent on gas flow to the heaters. The emissions estimate for the proposed heating medium heaters is based on the maximum heat input capacity of each heater and thus, the GHG emissions during startup, normal operation, or shutdown would not exceed the maximum estimated amount.

2. ***Beginning on page 10-4 of the permit application, EPA notes the differences between the applicant's proposed project and the provided examples of existing and proposed projects that utilized CCS; it is important to be mindful that BACT is a case-by-case determination.***

The control alternatives evaluated should include not only existing controls for the source category in question, but also (though technology transfer) controls applied to similar source categories and gas streams. This requires more site specific facility information to thoroughly evaluate and eliminate CCS from consideration. This information should contain detailed information on the quantity and quality of % CO_2 content in the stream.

Please provide a detailed cost analysis of the equipment design.

Please include cost of construction, operation, and maintenance of the technologies evaluated.

Also, include the feasibility of storage or transportation and cost analysis for these options.

Would there be energy penalties associated with the site-specific CCS technology? If so, please include a detailed cost analysis.

Please discuss in detail any site specific safety or environmental impacts associated with such a removal system.

Response:

A discussion of the use of Carbon Capture and Sequestration for the control of primarily CO_2 emissions from the proposed Liquefaction Project begins in Section 10 of the PSD GHG permit application.

As shown in Table 7-3 of the GHG PSD permit application, the major sources of GHG emissions from the proposed Liquefaction Project are from the proposed heating medium heaters, the Amine Unit/Thermal Oxidizers, the Combustion Turbine, and the Liquefaction Ground Flare.

Heating Medium Heaters

For the proposed heating medium heaters, it is possible to design and engineer a system to capture, transfer, and sequester the CO_2 separated from the heater exhaust stream. However, the feasibility of CCS is highly dependent on a continuous CO_2 laden exhaust stream, and CCS has not been tested or demonstrated for such small combustion sources. As discussed in Section 5.2 of the GHG PSD permit application, it is anticipated that for most of a year when the combustion turbine and waste heat recovery system are in operation, only two of the heating medium heaters will be operated to meet the energy requirements of the amine treatment system. The full complement of ten (10) heating medium heaters will only be needed during those occasions when the combustion turbine is down for scheduled MSS events; estimated to be about 14 days each year. Due to the limited hours of operation of the heating medium heaters, CSS is not considered a technically feasible option for these heaters.

Flares

The proposed Liquefaction Ground Flare and NGL Flare will be used to control releases to the atmosphere during emergency events or during scheduled MSS activities. As discussed in Section 10.5 of the GHG PSD application, the control of vent gas to the flare results in the creation of additional CO_2 emissions via the combustion mechanism. However, with no ability to collect exhaust gas from a flare other than using an enclosure, post combustion capture is not a viable control option.

Emergency Generator and Firewater Pump Engines

GHG emissions from the emergency generator engines and firewater pumps, electric circuit breakers, and fugitive emission sources are relatively insignificant compared to the other emission sources and as such, these emission sources would not be viable candidates for CCS. As discussed in Section 10.6, each emergency generator and firewater pump engine will be limited to 100 hours per year of operation for purposes of maintenance and testing. CSS is not considered an available control option for emergency equipment since it operates on an intermittent basis and must be immediately available during plant emergencies without the constraint of starting up a CSS process.

Of the remaining GHG emission sources, the Amine Unit/Thermal Oxidizers and the Combustion Turbine, it is possible to design and engineer a system to capture, transfer, and sequester the CO_2 separated from the exhaust stream because these emission sources will operate on a relatively continuous basis and will be located at the same site, in close proximity to each other.

Amine Units/Thermal Oxidizers

As discussed in Section 10.4 of the GHG PSD permit application, the primary source of CO_2 emissions from the thermal oxidizers will be from routing of CO_2 emissions from the amine units. Processed-based CO_2 emission rates for the thermal oxidizers were estimated based on the estimated flow rate of CO_2, assuming a two percent concentration in the incoming natural gas stream is CO_2. The evaluation of CSS was based on the capture and transfer of the CO_2-laden stream upstream of the Thermal Oxidizers.

While the process exhaust stream from the thermal oxidizer is relatively high in CO_2 content, additional processing of the exhaust gas will be required to implement CCS. These include separation (removal of particulate matter and other pollutants from the combustion gases), capture and compression, transfer, and sequestration of the CO_2 stream. These processes require additional equipment to reduce the exhaust temperature, large compression units, and pipelines to transfer CO_2. These additional units would require additional electricity and generate additional air emissions.

Freeport LNG conducted research and analysis to determine the technical and economic feasibility of CCS. Since most of the CO_2 emissions from the proposed project are generated from the amine units, Freeport LNG conducted studies to evaluate potential options to capture and geologically sequester CO_2 from the amine units or transfer the CO_2 to an off-site facility for Enhanced Oil Recovery (EOR). Based on these studies, Freeport LNG identified the following options as technically feasible:

- **Capture and Geological Sequestration of CO_2 (without any post-processing):** Based on the geological and subsurface studies conducted by Freeport LNG, capture and sequestration of CO_2 from the amine treatment units is technically feasible.

- **Capture and Transfer of CO_2 (with post-processing) for EOR:** Based on the results of these studies, capture and transfer of CO_2 from the amine treatment units for use in EOR is technically feasible. A study was performed to evaluate the potential options for capture and transfer of CO_2 from the Pretreatment Facility (located near Stratton Ridge, TX) to Denbury Resources, Inc. (Denbury) Facility (in Hastings, TX). The transfer of the CO_2 stream will require further treatment to remove contaminants and compression for transfer via a new pipeline.

A discussion of the energy, environmental, and economic impacts of CCS as it might apply to CO_2 from the amine treatments units, assuming the CO_2 stream is captured upstream of the thermal oxidizers is provided in Section 10.4.4 of the GHG PSD permit application.

Geological Sequestration – CO_2 Stream from Amine Treatment Units

Assuming the potential technical viability of CO_2 geological sequestration, the feasibility study included a preliminary cost analysis of geological sequestration. The estimated cost of an injection well was estimated to be approximately $4 million. The cost of electric-driven compression facilities to force the CO_2 into the aquifer with a wellhead injection pressure of approximately 1500 psia was estimated to be around $39 million. The total capital cost of geological sequestration, including engineering, was projected to be approximately $46 million. The annual operating and maintenance costs were estimated to be approximately $9 million, with almost 90% of the cost being power for the compressors. The average annual CO_2 control cost, based on a 30-year period and an 8.0% interest rate applied to the capital costs, was estimated to be nearly $13 million, or approximately $14/ton of CO_2 sequestered. This would represent a very burdensome expense for the Pretreatment Facility, increasing its overall operating costs substantially without any revenue or other offset, so geological sequestration is not regarded as an economically feasible CO_2 control option. A breakout of these cost estimates is provided in Table 1.

Enhanced Oil Recovery - CO_2 Stream from Amine Treatment Units

Assuming the potential technical viability of transferring of the CO_2 laden stream to an off-site facility; i.e., Denbury, for Enhance Oil Recovery, an evaluation was undertaken to develop a preliminary design and cost for the necessary treatment and compression facilities. Denbury requires very clean CO_2, with most of the sulfur compounds and water removed from the CO_2 effluent of the amine units. Denbury also requires delivered CO_2 at very high pressures for its EOR project, so compression of the treated CO_2 would be required at the Pretreatment Facility to around 2000 psia. The cost for treatment, compression, and delivery to Denbury is estimated to be $115 million. The annual operating and maintenance expenses were estimated to be approximately $9.6 million, with about 80% of the cost being power. Thus, the average annual CO_2 control cost, based on a 30-year period and an 8.0% interest rate applied to the capital costs, was estimated to be nearly $20 million, or about $22/ton of CO_2 removed. A breakout of these cost estimates is provided in Table 2.

Table 1

Option One: Geological Sequestration of CO_2 From Amine Treatment Units
Proposed Pretreatment Facility
Freeport LNG Development, L.P.

CAPEX	**$43,216,311**
Well - 6000' 2 casings; 1 injection Tubing	$4,000,000
Compression equipment	$39,216,311
Equipment cost	$13,053,606
Bulk materials	$9,881,236
Labor	$9,003,725
Tax	$205,950
Contingency	$7,071,794

Engineering	$3,214,452

OPEX	**$8,974,573**
Electricity	$7,787,928
Water disposal	$31,303
Repair Material	$421,181
Contract Maintenance services	$699,161
Chemicals and Lubes	$35,000

Amortized CCS Cost

Total Capital Investment (TCI)	**$46,430,763**
Capital Recovery Factor (CRF) = i(1+i)n/((1+i)n-1)	**0.09**
I = interest rate	0.08
n= equipment life, years	30
Amortized Installation Costs = CRF * TCI	**$4,124,325**
Total CCS Annualized Cost	**$13,098,898**

Tons CO_2 per Year Removed (CO_2 from 3 Amine Units)	**896,334**
Average Annual Cost per Ton CO_2 Removed (Assuming 100% Capture and Storage)	**$14.61**

Assumptions:

Transport 42 MMSCF/D of CO2 with 7 psi supply pressure and 1900 psi delivery pressure through 37 miles of 10" pipeline (ANSI 900# system rated to 2200 psi).
Gas treatment/dehydration at supply side
Pump/Compressor (Supply: 7 psi, Delivery: 1900 psi, 42 MMSCF/D)
Dehydration Unit (Supply: 5.3899% H2O Molar, Delivery: < 30 # water vapor/1,000 MCF)
Sulfa Treatment Unit (Supply: 0.0189% H2S Molar, Delivery: < 35 ppm Sulfur by weight)
37 mi. pipeline (Stratton Ridge to Hastings)
10" x 0.500" pipe (ANSI 900# per CFR 192) calculated
5 main line valve stations (10" Gate Valves w/ 4" blow-downs)

Table 2

Option Two: Enhanced Oil Recovery Using CO_2 From Amine Treatment Units
Proposed Pretreatment Facility
Freeport LNG Development, L.P.

CAPEX	**$106,504,679**
Pipeline	$39,468,363
Material	$9,976,724
Construction	$22,008,464
Survey	$983,175
Land (ROW)	$6,500,000
Compression/Treatment	$67,036,316
Equipment cost	$21,809,730
Bulk materials	$12,244,110
Labor	$11,080,338
Tax	$1,927,310
Contingency	$19,974,828

Engineering	$8,478,332

OPEX	**$**	**9,578,325.01**
Fuel	$	51,223.23
Electricity	$	7,787,928.00
Water Disposal	$	34,432.86
Repair Material	$	612,684.56
Contract Maintenance services	$	1,017,056.36
Chemicals and Lubes	$	75,000.00

Amortized CCS Cost

Total Capital Investment (TCI)	**$114,983,011**
Capital Recovery Factor (CRF) = i(1+i)n/((1+i)n-1)	**0.09**
I = interest rate	0.08
n= equipment life, years	30
Amortized Installation Costs = CRF * TCI	**$10,213,646**
Total CCS Annualized Cost	**$19,791,971**

Tons CO_2 per Year Removed (CO_2 from 3 Amine Units)	**896,334**
Average Annual Cost per Ton CO_2 Removed (Assuming 100% Capture and Transfer)	**$22.08**

Assumptions:

Transport 42 MMSCF/D of CO2 with 7 psi supply pressure and 1900 psi delivery pressure through 37 miles of 10" pipeline (ANSI 900# system rated to 2200 psi).
Gas treatment/dehydration at supply side
Pump/Compressor (Supply: 7 psi, Delivery: 1900 psi, 42 MMSCF/D)
Dehydration Unit (Supply: 5.3899% H2O Molar, Delivery: < 30 # water vapor/1,000 MCF)
Sulfa Treatment Unit (Supply: 0.0189% H2S Molar, Delivery: < 35 ppm Sulfur by weight)
37 mi. pipeline (Stratton Ridge to Hastings)
10" x 0.500" pipe (ANSI 900# per CFR 192) calculated
5 main line valve stations (10" Gate Valves w/ 4" blow-downs)

Combustion Turbine

Page 10-4 of Freeport LNG's GHG PSD Permit Application presents a discussion of Potential CO_2 Control Strategies for the proposed PTF Combustion Turbine including a discussion of nine projects that utilize an absorber medium, such as ammonia or amine, to remove CO_2 from the exhaust of coal-fired boilers in the power and industrial sector. Three additional examples were provided of industrial facilities that utilized an absorber based CCS technology. This discussion emphasizes that carbon capture could be accomplished with low pressure scrubbing of CO_2 from the exhaust stream using solvent (e.g., amines and ammonia), solid sorbent, or membrane technology. However, only solvents have been used to-date on a commercial (yet slip stream) scale.

The available post-combustion capture technologies include oxy-combustion; solvent capture and stripping; and post-combustion membranes. The oxy-combustion technology is still in the research stage and solvent capture and stripping technology is being implemented in the chemical industry. The post-combustion membrane technology is still in the research stage, and its industrial application is at least 10 years away.[1] Membrane separation of CO_2 from a combustion turbine exhaust stream is limited to relatively small applications. Materials of membrane construction must be made more permeable and less expensive than what is currently available in order for membrane capture to overcome the existing cost disadvantage compared to competing technologies.[2]

The U.S. Department of Energy's National Energy Technology Laboratory (DOE-NETL) provides the following brief description of state-of-the-art post-combustion CO_2 capture technology and related implementation challenges:

[1] *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Petroleum Refining Industry*, U.S. EPA, October 2010

[2] DOE/NETL-401/113009. Integration of H2 Separation Membranes with CO2 Capture and Storage. November 2009.

"...In the future, emerging R&D will provide numerous cost-effective technologies for capturing CO_2 from power plants. At present, however, state-of-the-art technologies for existing power plants are essentially limited to amine absorbents. Such amines are used extensively in the petroleum refining and natural gas processing industries... Amine solvents are effective at absorbing CO_2 from power plant exhaust streams—about 90 percent removal—but the highly energy-intensive process of regenerating the solvents decreases plant electricity output..."[3]

The DOE-NETL adds:

"...Separating CO_2 from flue gas streams is challenging for several reasons:

- *CO_2 is present at dilute concentrations (13-15 volume percent in coal-fired systems and 3-4 volume percent in gas-fired turbines) and at low pressure (15-25 pounds per square inch absolute [psia]), which dictates that a high volume of gas be treated.*
- *Trace impurities (particulate matter, sulfur dioxide, nitrogen oxides) in the flue gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes.*
- *Compressing captured or separated CO_2 from atmospheric pressure to pipeline pressure (about 2,000 psia) represents a large auxiliary power load on the overall power plant system..."*

In evaluation of alternative CCS techniques, the quality of the exhaust stream from the combustion turbine is of primary consideration. The exhaust steam from the combustion turbine contains a mixture of different constituents including products of combustion of natural gas fuel fired in the turbine; NO_x, SO_2, VOC, CO, and particulate matter. Depending on the final destination of the exhaust stream, these constituents may make the exhaust stream undesirable in terms of equipment or pipeline protection.

Absorber based technology has been applied to processes in the petroleum refining and natural gas processing industries to remove CO_2 from an incoming gas. Therefore, it is considered by Freeport LNG to be technically mature enough to warrant consideration.

[3] DOE-NETL, *Carbon Sequestration: FAQ Information Portal*, http://extsearch1.netl.doe.gov/search?q=cache:e0yvzjAh22cJ:www.netl.doe.gov/technologies/carbon_seq/FAQs/tech-status.html+emerging+R%26D&access=p&output=xml_no_dtd&ie=UTF-8&client=default

Though amine absorption technology for CO_2 capture has been applied to processes in the petroleum refining and natural gas processing industries and to exhausts from gas-fired industrial boilers, it is more difficult to apply to power plant gas tubine exhausts which have considerably large flow volumes and considerably less CO_2 concentrations. Based on a report produced in 2010[4], the Interagency Task Force on Carbon Capture and Storage supports this suggestion as follows:

"Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."

As discussed on Page 10-7 of Freeport LNG's GHG PSD Permit application, given the limited deployment of only slipstream/demonstration applications, CCS is not commercially available as BACT for the combustion turbine and is therefore, considered infeasible and not BACT for the proposed combustion turbine.

However, in response to this question, Freeport LNG has evaluated the estimated costs for implementation of CCS to the combustion turbine exhaust and transfer to either underground injection or enhanced oil recovery via pipeline.

Freeport LNG utilized the March 2010 National Energy Technology Laboratory (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 a pipeline and associated equipment. This document provides an appropriate method for estimation of transport, storage, and monitoring costs for a "typical" sequestration project. In addition, Freeport LNG estimated the capital and operating and maintenance cost of equipment necessary for separation of the CO_2 from the combustion turbine gas stream and amine treatment system exhaust stream, compression and transfer via pipeline to either underground injection or for Enhanced Oil Recovery.

[4] "Report of the Interagency Task Force on Carbon Capture and Storage," August 2010

For purposes of the cost analysis, Freeport LNG identified the following options as technically feasible:

- Capture and Geological Sequestration of CO_2 (without any post-processing)

  This analysis was based on the geological and subsurface studies conducted by Freeport LNG for capture and sequestration of CO_2 from the proposed amine treatment units.

- Capture and Transfer of CO_2 (with post-processing) for EOR

  This analysis was based on the results of studies for capture and transfer of CO_2 from the amine treatment units and transfer to Denbury Resources, Inc. (Denbury) Facility (in Hastings, TX). The transfer of the CO_2 stream will require further treatment to remove contaminants and compression for transfer via a new pipeline.

Geological Sequestration – CO_2 Stream from Combustion Turbine

As discussed in Section 10.4 of the GHG permit application, Freeport LNG previously undertook a feasibility study of geological sequestration of the roughly 42 million cubic feet per day (MMCFD) of CO_2, venting at atmospheric pressure, produced by the amine recovery units. Assuming the captured CO_2 from the combustion turbines would be routed to the same pipeline proposed for the amine treatment units, an additional 32 MMCFD of CO_2 (24 MMCFD from the combustion turbine and 8 MMCFD from an auxiliary heater) would be combined with the 42 MMCFD for a total of 74 MMCFD of CO_2 or about 1.4 MM tons per year of CO_2.

The total capital cost of geological sequestration based on this scenario was projected to be approximately $444 million. The annual operating and maintenance costs were estimated to be approximately $65 million. Thus, the average annual CO_2 control cost, based on a 30-year period and an 8.0% interest rate applied to the capital costs, was estimated to be nearly $131 million, or approximately $94/ton of CO_2 sequestered. A breakout of this cost estimate is provided in Table 3.

This cost would represent a very burdensome expense for the Pretreatment Facility, increasing its overall operating costs substantially without any revenue or other offset, so geological sequestration is not regarded as an economically feasible CO_2 control option.

Table 3

Option One: Geological Sequestration of CO_2 From Combustion Turbine Exhaut Stack
Proposed Pretreatment Facility
Freeport LNG Development, L.P.

CO_2 Pipeline/Injection Well Assumptions

Pipeline Length	38	miles
Pipeline Diameter	14	inches
Number of Injection Wells	1	
Depth of Well	1,000	meters

CSS Cost Breakdown

Cost Type	Units	Cost	
Pipeline Costs			
Pipeline Materials	$ Diameter (inches), Length (miles)	$64,632 + $1.85 x L x (330.5 x D² + 686.7 x D + 26,920)	$7,189,664
Pipeline Labor	$ Diameter (inches), Length (miles)	$341,627 + $1.85 x L x (343.2 x D² + 2,074 x D + 170,013)	$19,063,656
Pipeline Miscellaneous	$ Diameter (inches), Length (miles)	$150,166 + $1.58 x L x (8,417 x D + 7,234)	$7,659,489
Pipeline Right of Way	$ Diameter (inches), Length (miles)	$48,037 + $1.20 x L x (577 x D + 29,788)	$1,774,727
Other Capital			
Inlet Compression / Cooling	$	$20,000,000	$20,000,000
CO2 Compression Equipment	$	$28,800,000	$28,800,000
Cryogenic Units/Amine Units Dehydration	$	$378,000,000	$378,000,000
CO2 Surge Tank	$	$3,500,000	$3,500,000
Pipeline Control System	$	$340,000	$340,000
O&M - Pipeline			
Fixed O&M	$/mile/year	$8,632	$328,016
O&M - Capture			
Fixed O&M	% of installed capital	5.0%	$21,532,000
Natural Gas for Amine Regeneration	$ per MMBtu	$3.00	$9,214,128
Electricity for Compression	$ per MMBtu	$0.06	$11,785,711
Electricity for Inlet Blower	$ per MMBtu	$0.06	$8,184,522
Amine Replacement	$ per year		$3,000,000
		Total Capital Cost	**$466,327,53S**

Amortized CCS Cost

Total Capital Investment (TCI)	**$466,327,535**
Capital Recovery Factor (CRF) = i(1+i)n/((1+i)n-1)	**0.15**
I = interest rate	0.08
n= equipment life, years	10
Amortized Installation Costs = CRF * TCI	**$69,496,554**
Total CCS Annualized Cost	**$123,540,931**

Tons CO_2 per Year Removed (AGRU and CT)	**1,398,983**
Average Annual Cost per Ton CO_2 Removed (Assuming 100% Capture and Transfer)	**$88.31**

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Enhanced Oil Recovery - CO_2 Stream from Combustion Turbine

As previously noted, Freeport LNG undertook a feasibility study of using the roughly 42 MMCFD of CO_2 from the amine recovery units at the Pretreatment Facility as a supplemental supply to Denbury Resources' CO_2-injection EOR project in Hastings, Texas some 37 miles away. Assuming the captured CO_2 from the combustion turbine would be routed to the same pipeline proposed for the amine treatment units, an additional 32 MMCFD of CO_2 (24 MMCFD from the combustion turbine and 8 MMCFD from the auxiliary heaters) would be combined with the 42 MMCFD for a total of 74 MMCFD or about 1.4 MM tons per year of CO_2.

This CO_2 stream would contain sulfur compounds, particulate matter and other products of combustion, and water which would be removed farther downstream in the Pretreatment Facility. Denbury requires very clean CO_2, with most of the sulfur compounds and water removed from the CO_2 effluent of the amine units. Denbury also requires delivered CO_2 at very high pressures for its EOR project, so compression of the treated CO_2 would be required at the Pretreatment Facility to around 2000 psia. The cost for treatment, compression, and delivery to Denbury is estimated to be $466 million. The annual operating and maintenance expenses were estimated to be approximately $54 million. Thus, the average annual CO_2 control cost, based on a 30-year period and an 8.0% interest rate applied to the capital costs, was estimated to be nearly $124 million; about $88/ton of CO_2 captured and transferred. A breakout of this cost estimate is provided in Table 4.

Denbury confirmed its potential ability to accept the treated volumes at some time in the future, but its current and anticipated future alternative CO_2 supply costs are significantly less than $22/ton. If Freeport LNG were to sell its CO_2 to Denbury at their alternative cost, the net loss to Freeport LNG would represent a very burdensome expense for the Pretreatment Facility. Therefore, sale of CO_2 to Denbury for EOR is not regarded as a viable or economically feasible CO_2 control option.

Carbon capture and storage for the proposed combustion turbine would add such significant economic burden to the facility that the combustion turbine would no longer be a viable option for the facility. While the overall project will proceed, without the installation of the combustion turbine, the energy efficiency of the combined heat and power facility would be lost.

Table 4

Option Two: Enhanced Oil Recovery Using CO2 From Combustion Turbine Exhaut Stack
Proposed Pretreatment Facility
Freeport LNG Development, L.P.

CO_2 Pipeline/Injection Well Assumptions

Pipeline Length	5	miles
Pipeline Diameter	12	inches
Number of Injection Wells	1	
Depth of Well	1,000	meters

CSS 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)	\$830,462
Pipeline Labor	\$ Diameter (inches), Length (miles)	\$341,627 + \$1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013)	\$2,601,604
Pipeline Miscellaneous	\$ Diameter (inches), Length (miles)	\$150,166 + \$1.58 x L x (8,417 x D + 7,234)	\$1,005,246
Pipeline Right of Way	\$ Diameter (inches), Length (miles)	\$48,037 + \$1.20 x L x (577 x D + 29,788)	\$268,309
Other Capital			
Inlet Compression / Cooling	\$	\$20,000,000	\$20,000,000
CO2 Compression Equipment	\$	\$27,000,000	\$27,000,000
Cryogenic Units/Amine Units Dehydration	\$	\$378,000,000	\$378,000,000
CO2 Surge Tank	\$	\$3,500,000	\$3,500,000
Pipeline Control System	\$	\$340,000	\$340,000
O&M - Pipeline			
Fixed O&M	\$/mile/year	\$8,632	\$43,160
O&M - Capture			
Fixed O&M	% of installed capital	5.0%	\$21,442,000
Natural Gas for Amine Regeneration	\$ per MMBtu	\$3.00	\$9,214,128
Electricity for Compression	\$ per MMBtu	\$0.06	\$11,049,104
Electricity for Inlet Blower	\$ per MMBtu	\$0.06	\$8,184,522
Amine Replacement	\$ per year		\$3,000,000
Geologic Storage Costs Capital			
Site Screening and Evaluation	\$	4738488	\$4,738,488
Injection Wells	\$/injection well	\$240,714 x $e^{0.0008 \text{ x well depth}}$	\$535,719
Injection Equipment	\$/injection well	\$94,029 x $[7389/(280 \text{ x \# of injection wells})]^{0.5}$	\$483,032
Liability Bond	\$	\$5,000,000	\$5,000,000
Declining Capital Funds			
Pore Space Acquisition	\$/short ton CO2	0.334/short ton CO_2	**\$467,260**
		Total Capital Cost	**\$444,302,859**
O&M - Geologic Storage			
Normal Daily Expenses (Fixed O&M)	\$/injection well	\$11,566	\$11,566
Consumables (Variable O&M)	\$/yr/short ton CO2/day	\$2,995	\$11,937,195
Surface Maintenance (Fixed O&M)	see formula	\$23,478 x $[7389/(280 \text{ x \# of injection wells})]^{0.5}$	\$120,608
Subsurface Maintenance (Fixed O&M)	\$/ft-depth/inject well	\$7.08	\$23,222

Amortized CCS Cost

Total Capital Investment (TCI)	**\$444,302,859**
Capital Recovery Factor (CRF) = i(1+i)n/((1+i)n-1)	**0.15**
I = interest rate	0.08
n= equipment life, years	10
Amortized Installation Costs = CRF * TCI	**\$66,214,228**
Total CCS Annualized Cost	**\$131,239,733**

Tons CO_2 per Year Removed (AGRU and CT)	**1,398,983**
Average Annual Cost per Ton CO_2 Removed (Assuming 100% Capture and Transfer)	**\$93.81**

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A more detailed discussion of the Carbon Sequestration and Enhanced Oil Recovery studies conducted by Freeport LNG is provided in Freeport LNG's GHG PSD permit application.

In summary, the site specific application does present significant challenges to CCS. Some of those challenges are:

1. **Competing Technologies**: As detailed above, the only technology that Freeport LNG, along with published experts in the field, considers mature enough to warrant serious consideration for CCS is absorption technology.

2. **Economic Feasibility**: The low purity and concentration of CO_2 in the combustion turbine exhaust and the relatively small size of the proposed combustion turbine facility means that the per ton cost of removal and storage will no doubt be much higher than the public data estimates for much larger fossil fuel power facilities due to the loss of economies of scale. Based on the CCS evaluation by Freeport LNG discussed above, the average annual CO_2 control cost, estimated to be about $88/ton of CO_2, would result in an added cost to the project in the range of $124,000,000 per year. This is more than four times the "best case" estimated economic benefit derived by the installation of the combustion turbine as a combined heat and power facility. In other words, a capture and storage scheme that costs as low as $40 per ton would negate any economic benefit offered by the combustion turbine facility. Thus, the most energy efficient means of providing combined thermal and electrical energy to the proposed project, per the EPA, will not be utilized if CCS is imposed.

3. **Energy penalty**: It is estimated that the estimated energy penalty associated with the installation of a CCS system would be about 62-63% of produced energy from the combustion turbine, as shown in Table 5. Since the facility thermal energy need is approximately equal to the recoverable exhaust energy of the proposed combustion turbine, a larger combustion turbine would be required to meet the additional energy requirements for CCS. Assuming approximately 30 to 45% more fuel will be required to produce this additional electric output, it is estimated that an additional 3.5 billion cubic feet of natural gas per year would be burned that would produce an additional 209,000 tons of CO_2 per year just to support the electrical energy requirements for CCS. At the estimated $88 per ton CO2 described above, the energy penalty associated with CCS will by itself add an additional economic burden to the project of about $18,400,000 per year.

4. **Long-term storage uncertainty**: A study of the risks associated with long-term geologic storage of CO_2 places those risks on par with the underground storage of natural gas or acid-gas.[5] The liability of underground CO_2 storage, however, is less understood. A recent publication from the Massachusetts Institute of Technology (MIT) states that "The characteristics (of long term CO_2 storage) pose a challenge to a purely private solution to liability."[6] Since Freeport LNG is a private entity, and the liability issues of long-term CO_2 storage are in a state of flux, the imposition of CCS on the project may cause Freeport LNG to seek a less energy efficient solution than the combustion turbine based combined heat and power system.

[5] Benson, S. 2006. "CARBON DIOXIDE CAPTURE AND STORAGE, Assessment of Risks from Carbon Dioxide Storage in Deep Underground Geological Formations." Lawrence Berkley National Laboratory
[6] de Figueiredo, M., 2007. "The Liability of Carbon Dioxide Storage," Ph.D. Thesis, MIT Engineering

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Table 5 – Combustion Turbine CCS Energy Penalty Estimate

Combustion Turbine	GE Frame 7EA	GE Frame 7EA
CT Cycle Operating Mode	CHP	CHP
CT Inlet Dry Bulb Temperature, °F	60	60
Gross CT Power Output, kW	87,470	87,470
CT Plant Auxiliary Loads, kW (estimated)	(3061)	(3920)
Net CT Plant Electrical Output, kW	**84,409**	**84,409**
CT Natural Gas Fuel Input, MMBtu/hr LHV	906	906
Process Thermal Energy from CT Exhaust, MMBtu/hr	406	406
Total Useful Energy Output, kW equivalent	**203,365**	**203,365**
Carbon Capture Method	Amine Absorber	Amine Absorber
Carbon Sequestration Method	Geologic	EOR
Amine Regenerator Heater Fuel Input, MMBtu/hr LHV	303	303
Electrical Input to Inlet Blower/Cooler, kW	16,239	16,239
Electrical Input to CO_2 Compression, kW	21,293	23,384
Total Energy Penalty, kW Equivalent	**129,940**	**128,401**
Energy Penalty, % of Useful Energy Output	**62.4%**	**63.1%**

*CHP = Combined Heating and Power

3. ***Please provide a spreadsheet that details the cost information provided in the permit application beginning on Page 10-21.***

Response:

Tables detailing the cost information relating to CCS of the CO_2 stream from the amine treatment units as provided in the permit application beginning on Page 10-21 are included as Tables 1 and 2 to this document in response to Comment No. 2. The estimate of cost is provided for two scenarios: 1) assumes the feasibility of geological sequestration of CO_2 effluent from the amine treatment units (Table 1); and 2) assumes the feasibility of Enhanced Oil Recovery using the CO_2 effluent from the amine treatment units (Table 2). A more detailed discussion of the assumptions is found in Section 10.4.4.1 and 10.4.4.2 of Freeport LNG's Greenhouse Gas PSD Application.

4. ***How will the air/fuel ratio be assured during operation of the combustion turbine, i.e., alarms, alerts, computer monitored, etc?***

Will O_2 analyzers be utilized?

What will be the target ratio?

What are the proposed monitoring and recordkeeping requirements for the combustion turbine's operating parameters?

Please provide more details of what will constitute good combustion, operating, and maintenance practices for the combustion turbine?

Please provide more information pertaining to the automation of the combustion turbine operation that will ensure optimal fuel combustion?

Please provide the designed efficiency and comparative benchmark data of the combustion turbine; i.e., comparison data of existing or similar combustion turbines.

How will the optimal operating parameters for the combustion turbine determined?

What is the company's proposed compliance monitoring methodology?

What will be the operating control parameters of the air chiller?

How will the air chiller be maintained to ensure if is operating properly and efficiently?

Response:

A. How will the air/fuel ratio be assured during operation of the combustion turbine, i.e., alarms, alerts, computer monitored, etc?

In general, GE Heavy-Duty Gas Turbine air/fuel ratios are maintained on set-point through measurement and control of the gas turbine exhaust temperature. Various application specific algorithms are used to establish target exhaust temperatures utilizing a range of input data from station instrumentation. The level of complexity deployed in these control algorithms vary with application, and are dependent on, but not limited to, the following particulars: control system architecture, combustion system design, site emissions requirements, site ambient range, system turndown requirements, CT load stability and/or grid frequency stability, heat recovery system requirements, and exhaust system geometry.

The CT control system maintains target temperatures through modulation of CT air-flow, while fuel-flow is modulated to hold the desired power output level. Various alarms and alerts are tied to the system's ability to maintain control of the exhaust temperature relative to the set-point reference. GE Heavy-Duty Gas Turbine control systems also monitor the spread of exhaust temperature data, which is generally measured at several locations. High spatial spread in turbine exhaust temperature is an indication of an undesirable state of combustion and will result in control system alarms and/or actions.

B. Will O_2 analyzers be utilized? What will be the target ratio?

Oxygen (O_2) analyzers are not used in traditional GE Gas Turbine Control System, however they are utilized in some limited applications where emissions measurements are utilized within the turbine exhaust temperature control algorithm to maintain very precise control of pollutant emissions.

C. What are the proposed monitoring and recordkeeping requirements for the combustion turbine's operating parameters?

The combustion turbine control system, as well as the plant control system, will record and electronically archive operating data gathered by combustion turbine instrumentation on a regular schedule with frequency determined by the data point in question. The archived data will be stored on a dedicated server with tape-drive back-up.

D. Please provide more details of what will constitute good combustion, operating, and maintenance practices for the combustion turbine?

Good Combustion Practices

Operational practices recommended by the manufacturer and monitoring and control of operating parameters will constitute good combustion practices.

Instrumentation and Controls

Modern combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system is a digital type and is supplied with the combustion turbine. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency, low-emissions performance.

General Operating and Maintenance Procedures

All combustion turbines degrade over time from a combination of blade fouling and blade wear. Plant operators will monitor the output and efficiency (performance) of the combustion turbine on a real-time basis through the plant computerized control system. When a predetermined level of performance degradation has been reached, a water wash will be initiated at a time when facility demand for thermal and electrical energy is not at its peak. Water wash will significantly reduce the efficiency of the combustion turbine during the actual wash but the improved performance following the wash justifies the effort. Performance degradation due to blade wear will be monitored on a monthly basis using data for the combustion turbine in its "clean" condition following water wash.

Modern combustion turbines have regularly scheduled maintenance programs. These maintenance programs are important for the reliable operation of the unit, as well as to maintain optimal efficiency. As the combustion turbine is operated, the unit experiences degradation and loss in performance. The combustion turbine maintenance program helps restore the recoverable lost performance. The maintenance program schedule is determined by the number of hours of operation and/or turbine starts. There are three basic maintenance levels, commonly referred to as combustion inspections, hot gas path inspections, and major overhauls. Combustion and hot gas path inspection will be performed at regular intervals, as follows:

- Every 12,000 operating hours the combustion turbine will undergo a combustion inspection and repair interval
- Every 24,000 operating hours the combustion turbine will undergo a hot gas path inspection and repair interval
- Every 48,000 operating hours the combustion turbine will undergo a major inspection and repair interval

Freeport LNG intends to follow the manufacturer's recommended maintenance and repair guidelines.

Periodic Burner Tuning

Combustion inspections are the most frequent of the maintenance cycles. As part of this maintenance activity, the combustors will be tuned to restore optimal high-efficiency, low-emissions performance.

E. Please provide more information pertaining to the automation of the combustion turbine operation that will ensure optimal fuel combustion?

Modern combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system is a digital type and is supplied with the combustion turbine. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency, low-emission performance.

F. Please provide the designed efficiency and comparative benchmark data of the combustion turbine; i.e., comparison data of existing or similar combustion turbines.

Manufacturer's published performance at ISO conditions was examined for two turbine models that fit the four selection criteria as detailed in Table 6.

Table 6 – Comparison GE Frame 7EA to Siemens Combustion Turbine

Combustion Turbine	GE Frame 7EA	Siemens SGT6-2000E
CT Cycle Operating Mode	CHP	CHP
NO_x Control Method	Dry Low NO_x	Dry Low NO_x
CT Inlet Dry Bulb Temperature, °F	60	60
Gross Output, kW	87,470	112,000
CT Fuel Input, MMBtu/hr LHV	906	1,127
Process Thermal Energy Required, MMBtu/hr	406	406
Process Thermal Energy from CT Exhaust, MMBtu/hr	406	406
CT Plant Auxiliary Loads, kW (estimated)	(3061)	(3920)
Net CT Electrical Output, kW	84,409	108,080
Total Useful Energy Required, MMBtu/hr	694	775
CT Plant Thermal Efficiency	76.6%	68.7%

*CHP = Combined Heating and Power

The GE Frame 7Ea was selected based on its suitability for the application, its relative efficiency in the application, and its widespread successful service.

G. How will the optimal operating parameters for the combustion turbine determined?

The optimal operating point of the combustion turbine was selected at the confluence of exhaust energy available for process thermal needs and for inlet chilling duty and combustion turbine inlet temperature. Since heavy duty frame combustion turbines increase in output and efficiency at lower compressor inlet temperatures, a 60 °F compressor inlet temperature was selected as a point that was well within the chilled water conditions produced in conventional commercially available chillers and where the energy to drive the inlet chilling could be derived from the gas turbine exhaust energy without the need for supplemental energy. The combustion turbine will be operated at base load while the chiller control package will maintain a constant chilled water supply temperature, up to the design capacity of the chiller units installed, to the combustion turbine inlet chilling coil. This will result in a constant combustion turbine inlet temperature at ambient dry bulb temperatures from 60 °F to just over 100 °F. At ambient dry bulb temperatures below 60 °F, the turbine will be allowed to increase output and unit efficiency in base load operation.

H. What is the company's proposed compliance monitoring methodology?

Compliance with this emission limit will be demonstrated by monitoring fuel consumption and performing calculations consistent with the calculations included in Appendix A of this document. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average short tons of CO_2e per year emission rates do not exceed these limits.

I. What will be the operating control parameters of the air chiller?

The combustion turbine and the chiller package control system, as well as the plant control system will monitor and archive periodic data points for operational data gathered from installed instrumentation. These data points will include gas turbine electrical output, combustion turbine fuel input, chilled water supply and return temperatures, energy input to the chillers, and the combustion turbine air inlet temperature. From these data the efficiency of the combustion turbine as well as the operational effectiveness of the combustion turbine and chiller combination can be determined.

J. How will the air chiller be maintained to ensure if is operating properly and efficiently?

The chiller operating efficiency and effectiveness will be monitored on a real time basis through chilled water supply and return temperature monitoring. A loss of chiller effectiveness will be reflected in a rise in combustion turbine inlet temperature and a drop in combustion turbine electrical output. Either condition will cause an alarm in the plant control system. Operators will then be alerted so that the cause of the loss can be determined. The absorption chiller technology selected is widely used in industry and commercial building applications so spare parts and service personnel are readily available in the Texas Gulf Coast area. Routine maintenance and repairs will be made in accordance with the manufacturer's recommendations.

5. ***Please explain if a combined cycle combustion turbine was considered for this project.***

If so, please provide the detailed analysis that substantiates the selection of the simple cycle combustion turbine; if not, please explain why it was not considered as a viable option for this project.

Response

The specific combustion turbine model was selected based on four primary factors. One, the unit electrical and recoverable thermal output were a close fit for the facility electrical and thermal needs. Two, only a single combustion turbine unit was required to avoid the costs of purchasing and installing two combustions turbines, two heat recovery exchangers, two catalyst modules, etc. Three, the selected combustion turbine is in widespread use throughout the world. It is well known for reliable and dependable operation and spare parts and upgrades are available from a wide variety of alternate market sources. Four, the combustion turbine utilizes a dry-low NO_x combustor to meet air quality BACT requirements and to conserve water resources.

The Pretreatment Facility will include one GE Frame 7EA simple cycle, natural gas-fired combustion turbine exhausting to a heat exchanger for waste heat recovery. The CT will have a nominal base-load gross electric power output of approximately 87 megawatts. The waste heat recovery unit will be used to transfer heat to hot oil. The hot oil will be used in the amine sweetening units and dehydration system units in lieu of burning natural gas fuel in these units.

Inclusion of the combustion turbine unit is driven by a desire for energy efficient operation. The proposed liquefaction project will produce a "waste" stream of methane and nitrogen called boil-off-gas (BOG) that will need to be removed from the liquefaction process through either venting, flaring or use in a fired heater or combustion turbine application. In the interest of energy efficiency a combustion turbine in combined heat and power service was selected as the most desirable method of handling the BOG. Combined heat and power (CHP) applications utilize a combustion turbine or reciprocating engine to generate electricity by burning fuel and then use a waste heat recovery unit to capture heat from the hot exhaust gas. In the case of the proposed facility the recovered waste heat will provide required thermal energy to the pretreatment process. The EPA website (http://www.epa.gov/chp/basic/index.html accessed 23 April, 2012) states that: "Because less fuel is burned to produce each unit of energy output, CHP reduces air pollution and greenhouse gas emissions."

The combustion turbine selected for this combined heat and power facility is well suited to the application. The recoverable exhaust energy matches the thermal needs of the facility and the electricity produced can be used internally when all three process trains are in operation.

The CT will normally operate at base load; transferring waste heat to hot oil for use in the amine treatment units. Power generated from the unit will be dispatched for use in the Pretreatment Facility or the Liquefaction Plant. Excess power will be dispatched for sale to the Electric Reliability Council of Texas power grid.

In a combined cycle power plant (CCPP), or combined cycle gas turbine (CCGT) plant, a gas turbine generator generates electricity, and the heat of its exhaust is used to make steam, which in turn drives a steam turbine to generate additional electricity. This last step enhances the efficiency of electricity generation, and combined-cycle plants can achieve efficiencies of about 60%.

To meet the energy needs of the Pretreatment Facility, the exhaust energy from the CT will not be used to produce steam that will drive a steam turbine generator. Rather, the combustion turbine will operate in combined heat and power mode with heat recovery for process thermal needs. The combustion turbine and heat recovery unit are expected to convert approximately 77% of the fuel input energy (on an LHV basis) into electrical and useful thermal energy (a total of 694 MMBtu/hr or 203 MW equivalent). This is a much higher percentage of useful energy extraction than conventional combined cycle operation without a useful thermal requirement.

The selection of the simple cycle turbine was for the purpose of transferring waste heat to hot oil for use in the amine treatment units. The use of steam to produce electric power would leave little available energy for use as alternative energy for the project. The GE Frame 7Ea was selected based on its suitability for the application, its relative efficiency in the application, and its widespread successful service. The use of a simple cycle combustion turbine exhausting to a heat exchanger for waste heat recovery will meet the requirements of the project in terms of energy and heat requirements.

6. ***In the BACT analysis on pages 10-16 and 10-17, the applicant proposes to install new heaters designed to optimize combustion efficiency.***

Please provide technical data that supports this statement; i.e., detailed manufacturer data on the design efficiency of the heaters and comparative benchmark data to existing or similar sources.

Please include maintenance and tune-up plans per manufacturer specifications and the good combustion and operating practices that will be implemented and how it will be monitored to ensure compliance.

What operating parameters will be in place and monitored to ensure the waste recovery heat exchanger is operating efficiently and transferring the heat needs to the amine sweetening unit and dehydrating system in lieu of burning natural gas fuel in the heater?

Response

Manufacturer's Data/Comparative Benchmark

The PTF will include the installation of new equipment, including the proposed heating medium heaters. In general, a more energy efficient heater technology burns less fuel and thus, reduces the production of GHG and other regulated air pollutants. The heaters will be fired on either BOG or pipeline-quality natural gas and will be controlled with a burner management system. In addition, the heaters will be equipped with ultra-Low-NOx, staged/quenching (flue gas recirculation) burners capable of meeting 5 ppm NOx that will be tuned for thermal efficiency. A "Thermal Fluid System Datasheet" providing the design parameters for the proposed heating medium heaters is provided in Appendix B to this document.

As shown in the attached data sheet, the thermal efficiency of each proposed heating medium heater is 80% on an LHV basis. This is consistent with the EPA's energy performance indicators for furnaces and process heaters. According to the EPA's guidance, the average thermal efficiency of furnaces is estimated at 75-90%.[7]

[7] *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Manager, Document Number LBNL-964E*, EPA, June 2008.

Good Combustion, Operating, and Maintenance Practices

Operating parameters and efficiency of the waste heat recovery exchanger are based on the physical characteristics of the unit which are determined by engineering design and construction. Combustion turbine exhaust gas is introduced into the exchanger, and the flow of heating medium is maintained by a pump and valve arrangement, in concert with the computer based control system, such that the exit temperature of the heating medium is in-line with the needs of the process. Because of the physics of such an arrangement very little needs be done by the operators other than monitor the control system for alarms indicating aberrant heating medium temperature or flows.

Freeport LNG will operate and maintain the heating medium heaters in accordance with the vendor-recommended operating procedures and operating and maintenance manuals. To maintain optimal performance, Freeport LNG will also:

- Calibrate and perform preventative maintenance checks of the fuel gas flow meters on an annual basis;
- Perform preventative maintenance checks of oxygen control analyzers on a quarterly basis; and
- Perform tune-ups of the heaters at a minimum of annually.

Good combustion operating and maintenance practices proposed for the heating medium heaters are summarized in Table 7.

Freeport LNG will maintain a file of all records, data, measurements, reports, and documents related to the operation of the proposed heaters, including, but not limited to, the following:

- Records or reports pertaining to significant maintenance performed; and
- Records relating to performance tests and monitoring of combustion equipment.

Heat Recovery Heat Exchanger - Monitored Operating Parameters

The heat recovery exchanger will be designed such that the thermal needs of the operating facility can be recovered from the combustion turbine exhaust stream without the need to burn additional natural gas fuel in stand-by fired heaters. Internal leaks or fouling will be indicated by a reduction in temperature or the flow of the heating medium exiting the waste heat recovery exchanger. Such a reduction will trigger alarms in the plant control system and will, in turn, alert the operators to investigate and take corrective action.

To maintain the efficiency of the system, Freeport LNG will monitor the temperature and flow at the exit of the waste heat recovery exchanger on a continuous basis.

Table 7
Summary of Good Combustion, Operating, and Maintenance Practices
Freeport LNG Development, L.P.

Good Combustion Technique	Practice	Standard
Operating Practices	Documentation of operating procedures; updated as required for equipment or practice changes Procedures to include startup, shutdown, malfunction Maintenance of operating logs/record keeping	Maintain written site specific operating procedures including startup, shutdown, and malfunction
Maintenance Knowledge	Training of personnel on applicable equipment and procedures	Equipment maintained by personnel with training specific to equipment
Maintenance Practices	Documentation of maintenance procedures, updated as required for equipment or practice changes Routinely scheduled evaluation, inspection, overhaul as appropriate for equipment involved Maintenance of maintenance logs/record keeping Following vendor recommendations	Maintain site specific procedures for best/optimum maintenance practices per vendor recommendations Schedule periodic evaluations, inspections, overhauls, as appropriate
Fuel quality analysis and fuel handling	Monitor fuel quality Periodic fuel sampling and analysis Only LNG derived Boil-off Gas (BOG) or pipeline quality natural gas will be used.	Fuel analysis at least once per year

7. What are the assumptions or bases used to calculate the heater emission limit cap?

How was it derived?

The application indicates the back-up heaters will only operate for 336 hours.

What basis was used to dictate the limiting criteria?

What are the proposed monitoring and recordkeeping requirements for the 336 hours per year limit for the heaters?

Response:

The Pretreatment Facility will include ten (10) heating medium heaters (EPNs: 65B-81A, 65B-81B, 65B-81C, 65B-81D, 65B-81E, 65B-81F, 65B-81G, 65B-81H, 65B-81I, and 65B-81J). Each heater will have a maximum heat input capacity of 85 MMBtu/hr and will combust BOG or pipeline natural gas. The heaters will be used to supplement or replace the energy from the gas CT for use in the pretreatment trains. When the CT is in operation, it will be necessary to operate two of the ten heating medium heaters to fully meet low temperature heating demands of the three pretreatment trains. The remaining eight heating medium heaters will be utilized only when the combustion turbine is not operational.

Emissions from the heaters will result from the combustion of natural gas. Hourly emission rates are based on the maximum heat input rating (MMBtu/hr) and emission factors from 40 CFR Part 98, Subpart C, Tables C-1 and C-2 for natural gas. Annual emission rates were based on maximum operation equivalent to 8,760 hrs/yr each for two (2) of the eight low temperature heaters and 336 hours (14 days x 24 hours/day) each per year for the remaining eight (8) heating medium heaters.

To allow for operational flexibility, Freeport LNG proposes to set an emissions cap for the ten heating medium heaters such the combined operation of the heaters will not exceed the emissions cap. This will allow for firing any combination of two or more heaters simultaneously, such that over a rolling 12-month period, the total emissions from the combined operation of the heaters will not be exceeded.

See Appendix A for detailed emission calculations for the heaters.

Freeport LNG will monitor emissions in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for General Stationary Fuel Combustion Sources. Compliance with this emission limit will be demonstrated by monitoring fuel consumption and performing calculations consistent with the calculations included in Appendix A of this document. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average short tons of CO_2e per year emission rates do not exceed these limits.

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8. ***The proposed BACT limit on page 10-1 for the annual emission cap for the low temperature and high temperature heater is 100,486 tpy.***

EPA does not intend to issue an emission's CAP as part of a BACT determination.

Please clarify if it is the intention of the applicant for the calculated individual mass per unit time (lb/hr) emissions of each heater presented on page 8 of the Appendix to be the proposed short-term BACT limit in lieu of an emissions cap?

Response:

Freeport LNG proposes the following short term CO2e emission limit for the each heater:

- Ten (10) heating medium heaters: 117 lb CO2e/MMBtu

This proposed emission limit is based on a 12-month rolling average basis and includes CO_2, CH_4, and N_2O emissions, with CO_2 emissions being more than 99% of the total emissions.

Compliance with this emission limit will be demonstrated by monitoring fuel consumption and performing calculations consistent with the calculations included in Appendix A of this document. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average short tons of CO_2e per year emission rates do not exceed these limits.

9. ***Please provide data on regenerative thermal oxidizer design efficiency, comparative performance benchmark data to similar units, any proposed operating and maintenance practices and the monitoring and recordkeeping requirements to ensure compliance with recommendations.***

Response:

Manufacturer's Data/Comparative Benchmark

The Regenerative Thermal Oxidizers (RTO) will destroy volatile organic compounds (VOCs) and odorous emissions vented to it from the amine treatment units. Emissions destruction will be achieved through the process of high temperature thermal oxidation converting the pollutants to carbon dioxide and water vapor while reusing the thermal energy generated to reduce operating costs.

VOC-laden process gas will enter the oxidizer through an inlet manifold to flow control, poppet valves that direct this gas into energy recovery chambers where it is preheated. The process gas and contaminants are progressively heated in the ceramic media beds as they move toward the combustion chamber.

Once oxidized in the combustion chamber, the hot purified air releases thermal energy as it passes through the media bed in the outlet flow direction. The outlet bed is heated and the gas is cooled so that the outlet gas temperature is only slightly higher than the process inlet temperature. Poppet valves alternate the airflow direction into the media beds to maximize energy recovery within the oxidizer. The high energy recovery within these oxidizers reduces the auxiliary fuel requirement and saves operating cost.

The RTO will achieve high destruction efficiency and self-sustaining operation with no auxiliary fuel usage at concentrations as low as 3-4% LEL (Lower Explosive Limit). If the waste gas is able to sustain combustion, the reduction in auxiliary fuel requirement also results in a reduction in the production of GHG and other regulated air pollutants.

A proposal from Anguil Environmental Systems, Inc. providing the design specifications for the proposed RTOs is included in Appendix C of this document. Since an equipment vendor has not yet been selected, the proposal should be considered representative of the type of equipment to be used.

Thermal Oxidizer Design Efficiency/Comparative Benchmark Data

The RTO will use a set of ceramic heat transfer beds in order to effectively carryout its heat recovery functions. Apart from being much more durable and also providing a much longer usage lifespan in comparison to the heat exchangers that are used in recuperative thermal oxidizers, the ceramic beds are also known to offer improved thermal efficiency. The thermal efficiency of the RTO is about 90 to 95 percent, in comparison to the 50 to 75 percent that is offered by recuperative thermal oxidizers. The increased thermal efficiency provided by RTO results in reduced energy savings and operational costs.[8]

As shown in the data sheet for the RTO provided in Appendix C, the proposed RTO will achieve 95 % Thermal Energy Recovery and 95% nominal heat transfer efficiency. The RTO will be designed for a VOC conversion efficiency of 99% or an outlet concentration of 20 ppmv as methane, whichever limit is more stringent.

Good Combustion and Operating Practices – Thermal Oxidizers

Freeport LNG will operate and maintain the thermal oxidizers in accordance with vendor-recommended operating procedures and operating and maintenance manuals. To maintain optimal performance, Freeport LNG will also:

- Calibrate and perform preventative maintenance checks of the fuel gas flow meters on an annual basis;
- Perform preventative maintenance checks of oxygen control analyzers on a quarterly basis; and
- Perform tune-ups of the oxidizers at a minimum of annually.

Good combustion practices proposed for the thermal oxidizer include, but are not limited to the following:

- Good air/fuel mixing in the combustion zone;
- Allowing sufficient residence time to achieve a VOC conversion efficiency of 99% or an outlet concentration of 20 ppmv as methane, whichever limit is more stringent;

[8] Ref: CycleTherm, 2012

- Maintenance of proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality;

- Good burner maintenance and operation;

- Monitoring and maintenance of proper operating temperature in the primary combustion zone; and

- Maintaining overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency.

Freeport LNG will maintain a file of all records, data, measurements, reports, and documents related to the operation of the proposed RTOs, including, but not limited to, the following:

- Records or reports pertaining to significant maintenance performed; and
- Records relating to performance tests and monitoring of the RTO.

RTO - Monitored Operating Parameters

The regenerative thermal oxidizer is designed to achieve a high level of VOC destruction with reduced auxiliary fuel consumption. The key parameter for environmental record keeping purposes is the combustion chamber temperature. The unit combustion chamber temperature set point will be at or above 1550-1700°F when receiving waste gas from the amine units. The following parameters will be monitored and recorded on a continuous basis:

- Combustion chamber temperature;
- Natural gas fuel flow to the RTO burner; and
- Waste gas flow to the RTO.

10. Please provide the basis used to select the TCEQ 28 MID LDAR program for fugitive emissions.

Were other TCEQ LDAR programs considered as a possibility for this project?

If so, what was the basis for elimination of the other programs?

Response:

Fugitive emissions of VOC can potentially result from piping component leaks. An estimate of these fugitive emissions was calculated using the methodology described in the TCEQ's document entitled, *"Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000,"* using emission factors for Oil and Gas Production Operations. A copy of this document is included in Appendix D of this document. Calculations were based on Title 30 Texas Administrative Code (30 TAC) Chapter 115 and 28MID leak detection and repair (LDAR) requirements.

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. However, fugitive GHG emissions can be reduced by utilizing a leak detection and repair (LDAR) program. There are several structured LDAR programs that have been developed as part of state and federal rulemaking and BACT requirements. Freeport LNG will implement the TCEQ's 28MID LDAR program to minimize emissions from piping fugitive leaks. While this operational practice is designed to reduce VOC emissions, it will have a collateral effect in minimizing potential GHG emissions as well.

Conventional 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 normally required for streams containing a high content of methane.

The TCEQ published BACT guidelines for fugitive emissions in the document *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.* Table 8 displays the State BACT recommendations based on the uncontrolled fugitive emission rates.

TABLE 8. TCEQ BACT SUMMARY FOR FUGITIVE VOC EMISSIONS

Uncontrolled Annual Fugitive VOC Emission Rate	Best Available Control Technology
< 10 tpy	May not require monitoring
10 tpy ≤ x < 25 tpy	28M
≥ 25 tpy	28VHP

The uncontrolled VOC annual fugitive emissions are estimated to be less than 10 tpy for the Liquefaction Project and therefore, the selection of the TCEQ's 28M or 28VHP programs was not appropriate.

Table 9 is a summary of the TCEQ's LDAR programs and the control efficiencies that may be achieved with each. Freeport LNG will implement a 28MID LDAR program, a program with more stringent requirements than either the 28M or 28VHP programs; therefore, exceeding the BACT requirements for the control of fugitive VOC emissions. The selection of the 28MID LDAR program was considered appropriate to meet the BACT requirements of the project.

As shown in Table 9, the 28LAER LDAR program is one of the TCEQ's most stringent LDAR programs, developed to satisfy LAER requirements in ozone non-attainment areas. Total VOC emissions from the project are not expected to exceed 25 tons per year, and thus, a nonattainment review for VOC is not required. As such, the use of the 28LAER LDAR program was not appropriate.

Freeport LNG believes that implementation of the 28MID LDAR program will reduce GHG emissions by 87%, thereby constituting BACT.

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Table 9 - Control Efficiencies for TCEQ Leak Detection and Repair Programs

Equipment/Service	28M	28RCT	28VHP	28MID	28LAER	Audio/Visual/ Olfactory
Valves						
Gas/Vapor	75%	97%	97%	97%	97%	97%
Light Liquid	75%	97%	97%	97%	97%	97%
Heavy Liquid	0%	0%	0%	0%	0%	97%
Pumps						
Light Liquid	75%	75%	85%	93%	93%	93%
Heavy Liquid	0%	0%	0%	0%	0%	93%
Flanges/Connectors						
Gas/Vapor	30%	30%	30%	30%	97%	97%
Light Liquid	30%	30%	30%	30%	97%	97%
Heavy Liquid	30%	30%	30%	30%	30%	97%
Compressors	75%	75%	85%	95%	95%	95%
Relief Valves (Gas/Vapor)	75%	97%	97%	97%	97%	97%
Open-ended Lines	75%	97%	97%	97%	97%	97%
Sampling Connections	75%	97%	97%	97%	97%	97%

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11. ***On page 7-3, does the GHG emission rates presented on Table 71 include maintenance, startup, and shutdown emissions?***

Response:

The table provided on page 7-3 includes GHG emissions rates for all maintenance startup, and shutdown (MSS) emissions. Specifically, the emission rates associated with the NGLFLARE and the LIQFLARE include emissions from planned MSS events from the NGL Removal Unit and liquefaction trains. Under typical operation, the GHG emissions from the flares are a result of natural gas combustion in the flare pilots. Additional emissions represented in the table and the associated emission calculations in Appendix A are the emission rates estimated from planned MSS events.

The Combustion Turbine (EPNs: CT1(A) and CT1(B)) will have a maximum of two planned startup and shutdown events for tuning and maintenance purposes during a calendar year. Emissions of CO_2 from natural gas combustion during a startup or shutdown event will not exceed full load operation; therefore the MSS emissions are conservatively included in the combustion emission GHG calculations for the combustion turbine.

The Combustion Turbine will have a GHG emission limit which includes GHG emissions from continuous combustion of fuel gas during normal operation and during planned MSS events. GHG emissions from the turbine are anticipated to be directly proportional to the amount of fuel fired in the turbine combustor so these emissions would increase or decrease dependent on gas flow to the turbine. It is anticipated that there would be two planned startup and shutdown events for tuning and maintenance purposes during a calendar year. However, for purposes of estimating emissions to establish the BACT limit, it was conservatively assumed combustion turbine would fire fuel, at maximum input capacity, on continuous year round basis. Thus, the GHG emissions during startup, normal operation, or shutdown would not exceed the maximum estimated emissions for the combustion turbine as shown in Appendix A.

12. Calculations for GHGs are provided in Appendix A.

The applicant included in footnotes the source of the formulas used in calculating the emissions for each emissions source, but neglected to provide the formula and demonstrate how emission rates themselves were determined with the exception of the Amine Units/Thermal Oxidizer, Ground Flare, and NGL Flare on pages 10, 11, and 12.

Please supplement Appendix A to indicate the formulas used in the calculations for both hourly and annual emission rates for all emission sources.

Please provide the calculations and rationale from the Callidus Technologies proposal dated 10/31/2011 and 9/12/2011, that were used to calculate the values for the Liquefaction and NGL Flare, respectively.

Response:

The GHG emission calculations in Appendix A were revised to include the formulas used in calculating the emissions for all sources.

Callidus Technologies Proposal Dated October 2, 2011

An excerpt from the Callidus Proposal dated October 2, 2011 is included in Appendix E of this document. This proposal is for the ground flare proposed for the Liquefaction Facility. The information in the proposal is based on a process data specification sheet, provided to Callidus by Freeport LNG, as shown in the second page of the proposal.

Callidus Technologies Proposal Dated September 12, 2011

An excerpt from the Callidus Proposal dated September 12, 2011 is included in Appendix F of this document. This proposal is for the NGL Flare proposed for the Pretreatment Facility. The information in the proposal is based on a process data specification sheet, provided to Callidus by Freeport LNG (copy also include in Appendix F) for two design cases, as shown in Table 10.

Table 10 – Basis for Callidus Proposal Dated September 12, 2011

Case 1	Maximum Design	Smokeless Design
Flowrate (lb/hr)	50,890	50,890
Required Pressure at flare inlet (psig)	11.014	11.014
Molecular Weight	51.83	51.83
LHV (btu/scf)	2695	2695
Temperature (°F)	132.3	132.3

Case 2	Maximum Design	Smokeless Design
Flowrate (lb/hr)	59,799	59,799
Required Pressure at flare inlet (psig)	14.134	14.134
Molecular Weight	75.9	75.9
LHV (btu/scf)	3898.6	3898.6
Temperature (°F)	327.9	327.9

13. ***Appendix A includes the emission calculations for the Amine Unit/Thermal Oxidizer, Ground Flare, and NGL Flare.***

While the formulas and calculations for each of these emissions sources are shown, the annual emissions calculations were done using the unit (metric tonnes/year).

Both Section 7 Emissions Calculations and the Air Contaminant Data table in Appendix A use the unit (tons/year) for annual emissions calculations.

Additionally, the formulas and calculations used for emission calculations for both Pretreatment GHG fugitive emissions and Liquefaction GHG fugitive emissions were done using (tons/year).

Please amend Appendix A so that both the calculations and the air contaminant emission rate values for each emission source are using the same unit (tons/year).

Response:

As shown in Appendix A, the GHG emission calculations for the Amine Unit/Thermal Oxidizer, Ground Flare, and NGL Flare were revised to reflect the annual emissions in tons/year.

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14. ***Please supplement the GHG Potential Emissions Calculations table on page 8 of Appendix A to reflect annual emissions in tons/year.***

Response:

As shown in Appendix A, the GHG emission calculations on page 8 of Appendix A were revised to reflect annual emissions in tons/year.

15. Discrepancies were noted in the hourly emission estimates in lb/hr given on page 8.

For example, the hourly emission estimates in lb/hr for the three Amine Unit/Thermal Oxidizers given on page 8 do not match the hourly emission estimates given on page 2 or page 10.

Please explain the discrepancy between the hourly emission estimates for each of the three Amine unit/Thermal oxidizers and provide calculations and other evidentiary support to explain the discrepancy.

Note than any changes in hourly emissions calculations for any of the three Amine unit/Thermal Oxidizers may impact the total emission calculations.

Please provide the calculations and rationale for the Anguil Environmental Systems Thermal Oxidizer Proposal dated September 28, 2011 used to obtain CO_2 molar flow rates.

Response:

The hourly emission rates for each Thermal Oxidizer (EPNs: TO1, TO2, and TO3) given on page 2 of the emission calculations are a sum of the emissions from the combustion of natural gas in each Thermal Oxidizer pilot, as represented on page 8, and the process emissions, as represented in page 10. The Thermal Oxidizer pilot emission calculations, originally represented on page 8, have been moved to pages 11 and 12 in the emission summary tables provided in Appendix A to more clearly show the total lb/hr and ton/year as represented on page 2 of the emission calculations.

Anguil Environmental Systems Thermal Oxidizer Proposal Updated June 8, 2011

An excerpt from the Anguil Environmental Systems Thermal Oxidizer Proposal updated June 8, 2012 is included in Appendix C of this document. The information in the proposal is based on a process data specification sheet, provided to Anguil by Freeport LNG, as shown in the Page 4 of the proposal.

16. **In the BACT Analysis for the Amine Units/Thermal Oxidizers one of the selected BACT options was the use of boil-off gas (BOG) or natural gas as fuel.**

Yet, in the emissions estimates section of the application, emission estimates for the Amine Units/Thermal oxidizers appear to have only been calculated using natural gas.

Is the fuel composition of BOG similar to natural gas?

Please provide the emissions estimates for the Amine Units/Thermal Oxidizers using BOG as fuel.

Response:

The proposed liquefaction project will produce a "waste" stream of methane and nitrogen called boil-off-gas (BOG) that will need to be removed from the liquefaction process through either venting, flaring or use in a combustion source. BOG is comprised primarily of methane, up to 94%, and nitrogen. Natural gas consists of a high percentage of methane (generally above 85%) and varying amounts of ethane, propane, and inerts (typically nitrogen, carbon dioxide, and helium).[9] These two fuels have very similar properties and composition; therefore the use of the GHG Emission Factors for Natural Gas from 40 CFR Part 98, Subpart C, Table C-1 and C-2 are appropriate for both natural gas and BOG. Using these emission factors, the emission estimates for the Amine Units/Thermal Oxidizers are the same whether natural gas or BOG is used as fuel.

[9] U.S. EPA, AP-42, Section 1.4.1 Natural Gas Combustion (07/98)

17. Please provide the emails that are reference for the fugitive emissions calculations for the Pretreatment and Liquefaction Plants.

The emails are from Mr. Ruben Velasquez to Ms. Melissa Dakas.

The dates for the emails are October 7, 2011 and October 13, 2011 for Pretreatment and October 7, 2011 for Liquefaction.

Also, include the TCEQ Air Permit Technical Guidelines for Chemical Sources: Equipment Leak Fugitives (October, 2000).

Response:

A copy of the referenced emails is included in Appendix G of this document.

A copy of the TCEQ's *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000* is included Appendix D of this document.

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Appendix A

Updated GHG Emission Summary Tables

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TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	7/18/2012	**Permit No.:**	TBD	**Regulated Entity No.:**	RN103196689/TBA
Area Name:	Freeport LNG Development, L.P.			**Customer Reference No.:**	CN601720345

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TPY
65B-81A	65B-81A	Heating Medium Heater A	CO_2e	9945.22	--
			CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
65B-81B	65B-81B	Heating Medium Heater B	CO_2e	9945.22	--
			CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
65B-81C	65B-81C	Heating Medium Heater C	CO_2e	9945.22	--
			CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
65B-81D	65B-81D	Heating Medium Heater D	CO_2e	9945.22	--
			CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
65B-81E	65B-81E	Heating Medium Heater E	CO_2e	9945.22	--
			CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
65B-81F	65B-81F	Heating Medium Heater F	CO_2e	9945.22	--
			CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
65B-81G	65B-81G	Heating Medium Heater G	CO_2e	9945.22	--
			CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
65B-81H	65B-81H	Heating Medium Heater H	CO_2e	9945.22	--
			CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	7/18/2012	**Permit No.:**	TBD	**Regulated Entity No.:**	RN103196689/TBA
Area Name:	Freeport LNG Development, L.P.			**Customer Reference No.:**	CN601720345

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

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) POUND PER HOUR**	**(B) TPY**
65B-811	65B-811	Heating Medium Heater I	CO_2e	9945.22	--
			CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
65B-81J	65B-81J	Heating Medium Heater J	CO_2e	9945.22	--
			CO_2	9935.47	--
			N_2O	0.02	--
			CH_4	0.19	--
TO1	AU1/TO1	Amine Unit / Thermal Oxidizer 61	CO_2e	68799.20	301340.50
			CO_2	68798.63	301337.99
			N_2O	0.00	0.005
			CH_4	0.01	0.05
TO2	AU2/TO2	Amine Unit / Thermal Oxidizer 62	CO_2e	68799.20	301340.50
			CO_2	68798.63	301337.99
			N_2O	0.00	0.005
			CH_4	0.01	0.05
TO3	AU3/TO3	Amine Unit / Thermal Oxidizer 63	CO_2e	68799.20	301340.50
			CO_2	68798.63	301337.99
			N_2O	0.00	0.005
			CH_4	0.01	0.05
CT1 (A) & CT1 (B)	CT1 (A) & CT1 (B)	Combustion Turbine	CO_2e	128468.78	562693.25
			CO_2	128342.91	562141.93
			N_2O	0.24	1.06
			CH_4	2.42	10.60
NGLFLARE	NGLFLARE	NGL Flare	CO_2e	26.84	644.21
			CO_2	26.74	641.87
			N_2O	0.00	0.01
			CH_4	0.00	0.03
PTFFWP	PTFFWP	Fire Water Pump - Pretreatment	CO_2e	755.84	37.79
			CO_2	753.30	37.67
			N_2O	0.01	0.000
			CH_4	0.03	0.002

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	7/18/2012	**Permit No.:**	TBD	**Regulated Entity No.:**	RN103196689/TBA
Area Name:	Freeport LNG Development, L.P.			**Customer Reference No.:**	CN601720345

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

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) POUND PER HOUR**	**(B) TPY**
PTFEG-1	PTFEG-1	Emergency Generator Train 61	CO_2e	864.63	43.23
			CO_2	861.73	43.09
			N_2O	0.01	0.000
			CH_4	0.03	0.002
PTFEG-2	PTFEG-2	Emergency Generator Train 62	CO_2e	864.63	43.23
			CO_2	861.73	43.09
			N_2O	0.01	0.000
			CH_4	0.03	0.002
PTFEG-3	PTFEG-3	Emergency Generator Train 63	CO_2e	864.63	43.23
			CO_2	861.73	43.09
			N_2O	0.01	0.000
			CH_4	0.03	0.002
PTFEG-4	PTFEG-4	Emergency Generator Utility Area	CO_2e	864.63	43.23
			CO_2	861.73	43.09
			N_2O	0.01	0.000
			CH_4	0.03	0.002
FUG-TREAT	FUG-TREAT	Pretreatment Fugitives	CO_2e	99.96	437.82
			CO_2	0.00	0.000
			N_2O	0.00	0.000
			CH_4	4.76	20.85
FUG-PTFSF6	FUG-PTFSF6	Pretreatment Circuit Breakers	CO_2e	13.34	58.44
			SF_6	0.001	0.002
LIQFWP-1	LIQFWP-1	Fire Water Pump 1 - Liquefaction	CO_2e	755.84	37.79
			CO_2	753.31	37.67
			N_2O	0.01	0.000
			CH_4	0.03	0.002
LIQFWP-2	LIQFWP-2	Fire Water Pump 2 - Liquefaction	CO_2e	755.84	37.79
			CO_2	753.31	37.67
			N_2O	0.01	0.000
			CH_4	0.03	0.002

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TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	7/18/2012	**Permit No.:**	TBD	**Regulated Entity No.:**	RN103196689/TBA
Area Name:	Freeport LNG Development, L.P.			**Customer Reference No.:**	CN601720345

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

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) POUND PER HOUR**	**(B) TPY**
LIQEG-1	LIQEG-1	Emergency Generator 1 - Liquefaction	CO_2e	864.64	43.23
			CO_2	861.74	43.09
			N_2O	0.01	0.000
			CH_4	0.03	0.002
LIQEG-2	LIQEG-2	Emergency Generator 2 - Liquefaction	CO_2e	864.64	43.23
			CO_2	861.74	43.09
			N_2O	0.01	0.000
			CH_4	0.03	0.002
LIQEG-3	LIQEG-3	Emergency Generator 3 - Liquefaction	CO_2e	864.64	43.23
			CO_2	861.74	43.09
			N_2O	0.01	0.000
			CH_4	0.03	0.002
LIQEG-4	LIQEG-4	Emergency Generator 4 - Liquefaction	CO_2e	864.64	43.23
			CO_2	861.74	43.09
			N_2O	0.01	0.000
			CH_4	0.03	0.002
LIQFLARE	LIQFLARE	Ground Flare - Liquefaction	CO_2e	160.04	11523.03
			CO_2	159.89	11511.74
			N_2O	0.00	0.02
			CH_4	0.00	0.22
FUG-LIQ	FUG-LIQ	Liquefaction Fugitives	CO_2e	46.19	202.31
			CO_2	0.00	0.000
			N_2O	0.00	0.000
			CH_4	2.20	9.63
FUG-LIQSF6	FUG-LIQSF6	Liquefaction Circuit Breakers	CO_2e	77.52	339.56
			SF_6	0.003	0.014

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	7/18/2012	**Permit No.:**	TBD		
Area Name:	Freeport LNG Development, L.P.			**Regulated Entity No.:**	RN103196689/TBA
				Customer Reference No.:	CN601720345

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

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS											
1. Emission Point			4. UTM Coordinates of Emission Point			Source								
						5. Building Height (Ft.)	6. Height Above Ground (Ft.)	7. Stack Exit Data			8. Fugitives			
EPN (A)	FIN (B)	Name ©	Zone	East (Meters)	North (Meters)			Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
65B-81A	65B-81A	Heating Medium Heater A	15	275042	3208374		50.00	4.00	81.00	500			
65B-81B	65B-81B	Heating Medium Heater B	15	275068	3208372		50.00	4.00	81.00	500			
65B-81C	65B-81C	Heating Medium Heater C	15	275041	3208364		50.00	4.00	81.00	500			
65B-81D	65B-81D	Heating Medium Heater D	15	275068	3208362		50.00	4.00	81.00	500			
65B-81E	65B-81E	Heating Medium Heater E	15	275041	3208353		50.00	4.00	81.00	500			
65B-81F	65B-81F	Heating Medium Heater F	15	275067	3208352		50.00	4.00	81.00	500			
65B-81G	65B-81G	Heating Medium Heater G	15	275040	3208343		50.00	4.00	81.00	500			
65B-81H	65B-81H	Heating Medium Heater H	15	275067	3208342		50.00	4.00	81.00	500			
65B-81I	65B-81I	Heating Medium Heater I	15	275040	3208333		50.00	4.00	81.00	500			
65B-81J	65B-81J	Heating Medium Heater J	15	275066	3208331		50.00	4.00	81.00	500			
TO1	TO1	Amine Unit / Thermal Oxidizer 61	15	275047	3208441		80.00	2.50	50.00	170			
TO2	TO2	Amine Unit / Thermal Oxidizer 62	15	274930	3208447		80.00	2.50	50.00	170			
TO3	TO3	Amine Unit / Thermal Oxidizer 63	15	274813	3208452		80.00	2.50	50.00	170			
CT1 (A)	CT1 (A)	Combustion Turbine	15	275075	3208273		80.00	14.67	35.40	431			
CT1 (B)	CT1 (B)	Combustion Turbine	15	275075	3208263		80.00	14.67	35.40	431			
NGLFLARE	NGLFLARE	NGL Flare	15	274701	3208414		110	5.75	20.00	1832			
PTFFWP	PTFFWP	Fire Water Pump - Pretreatment	15	275046	3208063		10	0.83	140.00	1,187			
PTFEG-1	PTFEG-1	Emergency Generator Train 61	15	275126	3208437		10	0.5	220	810			
PTFEG-2	PTFEG-2	Emergency Generator Train 62	15	275008	3208442		10	0.5	220	810			
PTFEG-3	PTFEG-3	Emergency Generator Train 63	15	274891	3208448		10	0.5	220	810			
PTFEG-4	PTFEG-4	Emergency Generator Utility Area	15	275168	3208379		10	0.5	220	810			
FUG-TREAT	FUG-TREAT	Pretreatment Fugitives	15	274965	3208510								
FUG-PTFSF6	FUG-PTFSF6	Pretreatment Circuit Breakers	15	274965	3208510								
LIQFWP-1	LIQFWP-1	Fire Water Pump 1 - Liquefaction	15	273883	3202675		10	0.83	140.00	1,187			
LIQFWP-2	LIQFWP-2	Fire Water Pump 2 - Liquefaction	15	273881	3202678		10	0.83	140.00	1,187			
LIQEG-1	LIQEG-1	Emergency Generator 1 - Liquefaction	15	273784	3202131		10	0.5	220	810			
LIQEG-2	LIQEG-2	Emergency Generator 2 - Liquefaction	15	273583	3202028		10	0.5	220	810			
LIQEG-3	LIQEG-3	Emergency Generator 3 - Liquefaction	15	273381	3201926		10	0.5	220	810			
LIQEG-4	LIQEG-4	Emergency Generator 4 - Liquefaction	15	273878	3202163		10	0.5	220	810			
LIQFLARE	LIQFLARE	Ground Flare - Liquefaction	15	272945	3201737		7	0.25	0.00	1832			
FUG-LIQ	FUG-LIQ	Liquefaction Fugitive	15	273451	3202097								
FUG-LIQSF6	FUG-LIQSF6	Liquefaction Circuit Breakers	15	273451	3202097								

Liquefaction Project GHG Emissions Summary
Freeport LNG Development, L.P.

EPN	Description	Annual Emissions (tons/yr)				
		CO_2	CH_4	N_2O	SF_6	CO_2e [2]
PTFFWP	Fire Water Pump - Pretreatment	37.67	0.002	0.0003	--	38
PTFEG-1	Emergency Generator Train 61	43.09	0.002	0.0003	--	43
PTFEG-2	Emergency Generator Train 62	43.09	0.002	0.0003	--	43
PTFEG-3	Emergency Generator Train 63	43.09	0.002	0.0003	--	43
PTFEG-4	Emergency Generator Utility Area	43.09	0.002	0.0003	--	43
65B-81A	Heating Medium Heater A	43,517.36	0.821	0.0821	--	43,560
65B-81B	Heating Medium Heater B	43,517.36	0.821	0.0821	--	43,560
65B-81C	Heating Medium Heater C	1,669.16	0.031	0.0031	--	1,671
65B-81D	Heating Medium Heater D	1,669.16	0.031	0.0031	--	1,671
65B-81E	Heating Medium Heater E	1,669.16	0.031	0.0031	--	1,671
65B-81F	Heating Medium Heater F	1,669.16	0.031	0.0031	--	1,671
65B-81G	Heating Medium Heater G	1,669.16	0.031	0.0031	--	1,671
65B-81H	Heating Medium Heater H	1,669.16	0.031	0.0031	--	1,671
65B-81I	Heating Medium Heater I	1,669.16	0.031	0.0031	--	1,671
65B-81J	Heating Medium Heater J	1,669.16	0.031	0.0031	--	1,671
TO1	Amine Unit / Thermal Oxidizer 61	301,337.99	0.05	4.83E-03	--	301,341
TO2	Amine Unit / Thermal Oxidizer 62	301,337.99	0.05	4.83E-03	--	301,341
TO3	Amine Unit / Thermal Oxidizer 63	301,337.99	0.05	4.83E-03	--	301,341
NGLFLARE	NGL Flare	641.87	0.029	0.0056	--	644
CT1 (A) & CT1 (B)	Combustion Turbine	562,141.93	10.602	1.0602	--	562,693
FUG-TREAT	Pretreatment Fugitives	0.00	20.848	--	--	438
FUG-PTFSF6	Pretreatment Circuit Breakers	0.00	--	--	0.002	58
LIQFWP-1	Fire Water Pump 1	37.67	0.002	0.0003	--	38
LIQFWP-2	Fire Water Pump 2	37.67	0.002	0.0003	--	38
LIQEG-1	Emergency Generator 1	43.09	0.002	0.0003	--	43
LIQEG-2	Emergency Generator 2	43.09	0.002	0.0003	--	43
LIQEG-3	Emergency Generator 3	43.09	0.002	0.0003	--	43
LIQEG-4	Emergency Generator 4	43.09	0.002	0.0003	--	43
LIQFLARE	Ground Flare	11,511.74	0.217	0.0217	--	11,523
FUG-LIQ	Fugitives Liquefaction	--	9.634	--	--	202
FUG-LIQSF6	Liquefaction Circuit Breakers	--	--	--	0.01	340
Project Totals		**1,579,155.21**	**43.39**	**1.30**	**0.017**	**1,580,866**

Pretreatment Facility GHG Summary of Emissions

EPN	Description	Annual Emissions (tons/yr) CO_2	CH_4	N_2O	SF_6	CO_2e [1]
PTFFWP	Fire Water Pump - Pretreatment	37.67	1.53E-03	3.06E-04	--	38
PTFEG-1	Emergency Generator Train 61	43.09	1.75E-03	3.50E-04	--	43
PTFEG-2	Emergency Generator Train 62	43.09	1.75E-03	3.50E-04	--	43
PTFEG-3	Emergency Generator Train 63	43.09	1.75E-03	3.50E-04	--	43
PTFEG-4	Emergency Generator Utility Area	43.09	1.75E-03	3.50E-04	--	43
65B-81A	Heating Medium Heater A	43,517.36	0.82	0.08	--	43,560
65B-81B	Heating Medium Heater B	43,517.36	0.82	0.08	--	43,560
65B-81C	Heating Medium Heater C	1,669.16	0.03	3.15E-03	--	1,671
65B-81D	Heating Medium Heater D	1,669.16	0.03	3.15E-03	--	1,671
65B-81E	Heating Medium Heater E	1,669.16	0.03	3.15E-03	--	1,671
65B-81F	Heating Medium Heater F	1,669.16	0.03	3.15E-03	--	1,671
65B-81G	Heating Medium Heater G	1,669.16	0.03	3.15E-03	--	1,671
65B-81H	Heating Medium Heater H	1,669.16	0.03	3.15E-03	--	1,671
65B-81I	Heating Medium Heater I	1,669.16	0.03	3.15E-03	--	1,671
65B-81J	Heating Medium Heater J	1,669.16	0.03	3.15E-03	--	1,671
NGLFLARE	NGL Flare	641.87	0.03	5.58E-03	--	644
CT1 (A) & CT1 (B)	Combustion Turbine	562,141.93	10.60	1.06	--	562,693
TO1	Amine Unit / Thermal Oxidizer 61	301,337.99	0.05	4.83E-03	--	301,341
TO2	Amine Unit / Thermal Oxidizer 62	301,337.99	0.05	4.83E-03	--	301,341
TO3	Amine Unit / Thermal Oxidizer 63	301,337.99	0.05	4.83E-03	--	301,341
FUG-TREAT	Pretreatment Fugitives	--	20.85	--	--	438
FUG-PTFSF6	Pretreatment Circuit Breakers	--	--	--	2.45E-03	58
	Total Emissions	**1,567,395.79**	**33.53**	**1.27**	**0.002**	**1,568,552**

[1] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO_2e Annual Emission Rate (ton/yr) = CO_2 Emission Rate (ton/yr) x CO_2 GWP + CH_4 Emission Rate (ton/yr) x CH_4 GWP + N_2O Emission Rate (ton/yr) x N_2O GWP + SF_6 Emission Rate (ton/yr) x SF_6 GWP

Example CO_2e Emission Rate for PTFFWP (ton/yr) = $\frac{38 \text{ ton}}{\text{yr}} \Big| 1 + \frac{1.53\text{E-03 ton}}{\text{yr}} \Big| 21 + \frac{3.06\text{E-04 ton}}{\text{yr}} \Big| 310$ = 38 ton/yr

Per 40 CFR 98 - *Mandatory Greenhouse Gas Reporting*, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials

CO_2	1
CH_4	21
N_2O	310
SF_6	23,900

Liquefaction Plant GHG Summary of Emissions

EPN	Description	Annual Emissions (tons/yr)				
		CO_2	CH_4	N_2O	SF_6	CO_2e [1]
LIQFWP-1	Fire Water Pump 1	37.67	1.53E-03	3.06E-04	--	38
LIQFWP-2	Fire Water Pump 2	37.67	1.53E-03	3.06E-04	--	38
LIQEG-1	Emergency Generator 1	43.09	1.75E-03	3.50E-04	--	43
LIQEG-2	Emergency Generator 2	43.09	1.75E-03	3.50E-04	--	43
LIQEG-3	Emergency Generator 3	43.09	1.75E-03	3.50E-04	--	43
LIQEG-4	Emergency Generator 4	43.09	1.75E-03	3.50E-04	--	43
LIQFLARE	Ground Flare	11,511.74	0.22	0.02	--	11,523
FUG-LIQ	Fugitives Liquefaction	--	9.63	--	--	202
FUG-LIQSF6	Fugitives Liquefaction	--	--	--	0.01	340
	Total Emissions	**11,759.42**	**9.86**	**0.02**	**0.01**	**12,313**

[1] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO_2e Emission Rate (ton/yr) = CO_2 Emission Rate (ton/yr) x CO_2 GWP + CH_4 Emission Rate (ton/yr) x CH_4 GWP + N_2O Emission Rate (ton/yr) x N_2O GWP + SF_6 Emission Rate (ton/yr) x SF_6 GWP

Example CO_2e Emission Rate for LIQFWP (ton/yr) = $\frac{038 \text{ lb}}{\text{hr}} \Big| \ 1 + \frac{1.53\text{E-03 lb}}{\text{hr}} \Big| \ 21 + \frac{3.06\text{E-04 lb}}{\text{hr}} \Big| \ 310$ = 38 ton/yr

Per 40 CFR 98 - *Mandatory Greenhouse Gas Reporting*, Subpart A, Table A-1 Total CO_2e emissions are calculated based on the following Global Warming Potentials

CO_2	1
CH_4	21
N_2O	310
SF_6	23,900

Sources of GHG Emissions

Parameter	Units	Fire Water Pump - Pretreatment	Emergency Generator Train 61	Emergency Generator Train 62	Emergency Generator Train 63	Emergency Generator Utility Area	Heating Medium Heater A	Heating Medium Heater B	Heating Medium Heater C	Heating Medium Heater D	Heating Medium Heater E	Heating Medium Heater F	Heating Medium Heater G	Heating Medium Heater H	Heating Medium Heater I	Heating Medium Heater J	Combustion Turbine
EPN	-	PTFFWP	PTFEG-1	PTFEG-2	PTFEG-3	PTFEG-4	65B-81A	65B-81B	65B-81C	65B-81D	65B-81E	65B-81F	65B-81G	65B-81H	65B-81I	65B-81J	CTI (A) & CTI (B)
Rated Capacity [1]	MMBtu/hr	4.62	5.29	5.29	5.29	5.29	85	85	85	85	85	85	85	85	85	85	1098
Hours of Operation per Year	hrs/yr	100	100	100	100	100	8,760	8,760	336	336	336	336	336	336	336	336	8,760
Natural Gas Potential Throughput [2]	scf/yr	--	--	--	--	--	724,319,066	724,319,066	27,782,101	27,782,101	27,782,101	27,782,101	27,782,101	27,782,101	27,782,101	27,782,101	9,356,498,054
Diesel Potential Throughput [2]	gal/yr	3,300	3,775	3,775	3,775	3,775	--	--	--	--	--	--	--	--	--	--	--
Natural Gas High Heat Value (HHV) [3]	MMBtu/scf	--	--	--	--	--	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
No 2 Fuel Oil High Heat Value (HHV) [3]	MMBtu/gal	0.138	0.138	0.138	0.138	0.138	--	--	--	--	--	--	--	--	--	--	--

[1] Per AP-42 Table 3.3-1 Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines Brake Specific Fuel Consumption Factor = 7,000 BTU/hp-hr
[2] Natural gas throughput is based on heat capacity of the unit, hours of operation and the fuel's high heating value
[3] High heating value for No 2 Fuel Oil and Natural Gas obtained from 40 CFR Part 98, Subpart C, Table C-1

GHG Emission Factors for Diesel Fuel

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	73.960	kg CO_2/MMBtu
CH_4 [2]	0.003	kg CH_4/MMBtu
N_2O [2]	0.0006	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Distillate Fuel Oil No. 2
[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for petroleum fuel

GHG Emission Factors for Natural Gas

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	53.020	kg CO_2/MMBtu
CH_4 [2]	0.001	kg CH_4/MMBtu
N_2O [2]	0.0001	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Natural Gas.
[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for Natural Gas

GHG Potential Emission Calculations

EPN	Description	Fuel Type	Tier Used	Hourly Emissions [1,2] (lb/hr) CO_2	Hourly CH_4	Hourly N_2O	Hourly CO_2e [4]	Annual Emissions [3] (tons/yr) CO_2	Annual CH_4	Annual N_2O	Annual CO_2e [4]	BACT Limit lb CO_2e/MMBtu
PTFFWP	Fire Water Pump - Pretreatment	No 2 Fuel Oil	Tier I	753	0.03	6.11E-03	756	38	1.53E-03	3.06E-04	38	
PTFEG-1	Emergency Generator Train 61	No 2 Fuel Oil	Tier I	862	0.03	6.99E-03	865	43.1	1.75E-03	3.50E-04	43	
PTFEG-2	Emergency Generator Train 62	No 2 Fuel Oil	Tier I	862	0.03	6.99E-03	865	43	1.75E-03	3.50E-04	43	
PTFEG-3	Emergency Generator Train 63	No 2 Fuel Oil	Tier I	862	0.03	6.99E-03	865	43	1.75E-03	3.50E-04	43	
PTFEG-4	Emergency Generator Utility Area	No 2 Fuel Oil	Tier I	862	0.03	6.99E-03	865	43	1.75E-03	3.50E-04	43	
65B-81A	Heating Medium Heater A	Natural Gas	Tier I	9,935	0.19	0.02	9,945	43,517	8.21E-01	8.21E-02	43,560	117.00
65B-81B	Heating Medium Heater B	Natural Gas	Tier I	9,935	0.19	0.02	9,945	43,517	8.21E-01	8.21E-02	43,560	117.00
65B-81C	Heating Medium Heater C	Natural Gas	Tier I	9,935	0.19	0.02	9,945	1,669	3.15E-02	3.15E-03	1,671	117.00
65B-81D	Heating Medium Heater D	Natural Gas	Tier I	9,935	0.19	0.02	9,945	1,669	3.15E-02	3.15E-03	1,671	117.00
65B-81E	Heating Medium Heater E	Natural Gas	Tier I	9,935	0.19	0.02	9,945	1,669	3.15E-02	3.15E-03	1,671	117.00
65B-81F	Heating Medium Heater F	Natural Gas	Tier I	9,935	0.19	0.02	9,945	1,669	3.15E-02	3.15E-03	1,671	117.00
65B-81G	Heating Medium Heater G	Natural Gas	Tier I	9,935	0.19	0.02	9,945	1,669	3.15E-02	3.15E-03	1,671	117.00
65B-81H	Heating Medium Heater H	Natural Gas	Tier I	9,935	0.19	0.02	9,945	1,669	3.15E-02	3.15E-03	1,671	117.00
65B-81I	Heating Medium Heater I	Natural Gas	Tier I	9,935	0.19	0.02	9,945	1,669	3.15E-02	3.15E-03	1,671	117.00
65B-81J	Heating Medium Heater J	Natural Gas	Tier I	9,935	0.19	0.02	9,945	1,669	3.15E-02	3.15E-03	1,671	117.00
CTI (A) & CTI (B)	Combustion Turbine	Natural Gas	Tier I	128,343	2.42	0.24	128,469	562,142	10.6	1.06	562,693	
			Total	231,897.84	4.46	0.46	232,135	662,739.93	12.50	1.25	663,390	
			Total CO_2e Emissions [4]	-	-	-	232,135	-	-	-	663,390	

[1] CO_2 emissions from No 2 Fuel Oil and Natural Gas combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C
CH_4 and N_2O emissions No 2 Fuel Oil and Natural Gas combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C
Hourly Emissions (lb/hr) = Emission Factor (kg/MMBtu) x Rated Capacity (MMBtu/hr) x Conversion factor (lb/kg)

Example CO_2 Hourly Emissions (lb/hr) = $\frac{73.96 \text{ kg CO2}}{\text{MMBtu}} \times \frac{4.62 \text{ MMBtu}}{\text{hr}} \times \frac{2.2046 \text{ lb}}{\text{kg}}$ = 753 lb/hr

[2] kg to lb conversion 2.2046 lb/kg

[3] Annual Emissions (tons/yr) = Annual Emissions (lb/hr) x Annual Operating Hours (hr/yr) / Conversion factor (lb/tons)

Example CO_2 Annual Emissions (tons/yr) = $\frac{753 \text{ lb}}{\text{hr}} \times \frac{100 \text{ hr}}{\text{yr}} \times \frac{\text{tons}}{2000 \text{ lb}}$ = 38 tons/yr

[4] CO_2e emissions based on GWPs for each greenhouse gas pollutant
CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{753 \text{ lb}}{\text{hr}} \times 1 + \frac{0.03 \text{ lb}}{\text{hr}} \times 21 + \frac{6.11\text{E-03 lb}}{\text{hr}} \times 310$ = 756 lb/hr

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1 Total CO2e emissions are calculated based on the following Global Warming Potentials

CO_2	1
CH_4	21
N_2O	310

Sources of GHG Emissions

Source Name	Units	Fire Water Pump 1	Fire Water Pump 2	Emergency Generator 1	Emergency Generator 2	Emergency Generator 3	Emergency Generator 4
EPN	-	LIQFWP-1	LIQFWP-2	LIQEG-1	LIQEG-2	LIQEG-3	LIQEG-4
Rated Capacity	hp	660	660	755	755	755	755
Heat Input Capacity [1]	MMBtu/hr	4.62	4.62	5.29	5.29	5.29	5.29
Hours of Operation per Year	hrs/yr	100	100	100	100	100	100
Potential Throughput [2]	gal/yr	3,300	3,300	3,775	3,775	3,775	3,775
No.2 Fuel Oil High Heat Value (HHV) [3]	MMBtu/gal	0.138	0.138	0.138	0.138	0.138	0.138

[1] Per AP-42 Table 3.3-1 Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines Brake Specific Fuel Consumption Factor = 7,000 BTU/hp-hr
[2] 1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu
[3] High heating value for No 2 Fuel Oil obtained from 40 CFR Part 98, Subpart C, Table C-1

GHG Emission Factors for Diesel Fuel

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	73.960	kg CO_2/MMBtu
CH_4 [2]	0.003	kg CH_4/MMBtu
N_2O [2]	0.0006	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Distillate Fuel Oil No. 2
[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for petroleum fuel.

GHG Potential Emission Calculations

EPN	Description	Fuel Type	Tier Used	Hourly Emissions [1, 2] (lb/hr) CO_2	CH_4	N_2O	CO_2e	Annual Emissions [3] (tons/yr) CO_2	CH_4	N_2O	CO_2e
LIQFWP-1	Fire Water Pump 1	No.2 Fuel Oil	Tier I	753	3.06E-02	6.11E-03	756	37.67	1.53E-03	3.06E-04	37.79
LIQFWP-2	Fire Water Pump 2	No.2 Fuel Oil	Tier 1	753	3.06E-02	6.11E-03	756	37.67	1.53E-03	3.06E-04	37.79
LIQEG-1	Emergency Generator 1	No.2 Fuel Oil	Tier 1	862	3.50E-02	6.99E-03	865	43.09	1.75E-03	3.50E-04	43.23
LIQEG-2	Emergency Generator 2	No.2 Fuel Oil	Tier 1	862	3.50E-02	6.99E-03	865	43.09	1.75E-03	3.50E-04	43.23
LIQEG-3	Emergency Generator 3	No.2 Fuel Oil	Tier 1	862	3.50E-02	6.99E-03	865	43.09	1.75E-03	3.50E-04	43.23
LIQEG-4	Emergency Generator 4	No.2 Fuel Oil	Tier 1	862	3.50E-02	6.99E-03	865	43.09	1.75E-03	3.50E-04	43.23
			Total	4,953.57	0.20	0.04	4,970	247.68	1.00E-02	2.01E-03	249
			Total CO_2e Emissions [4]		-	-	4,970		-	-	249

[1] CO_2 emissions from No 2 Fuel Oil combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.
CH_4 and N_2O emissions No 2 Fuel Oil combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C
Hourly Emissions (lb/hr) = Emission Factor (kg /MMBtu) x Rated Capacity (MMBtu/hr) x Conversion factor (lb/kg)

Example CO_2 Hourly Emissions (lb/hr) = $\frac{73.96 \text{ kg CO2}}{\text{MMBtu}} \times \frac{4.62 \text{ MMBtu}}{\text{hr}} \times \frac{2.20462 \text{ lb}}{\text{kg}}$ = 753 lb/hr

[2] kg to lb conversion 2.20462 lb/kg

[3] Annual Emissions (tons/yr) = Annual Emissions (lb/hr) x Annual Operating Hours (hr/yr) / Conversion factor (lb/tons)

Example CO_2 Annual Emissions (tons/yr) = $\frac{753 \text{ lb}}{\text{hr}} \times \frac{100 \text{ hr}}{\text{yr}} \times \frac{\text{tons}}{2000 \text{ lb}}$ = 38 tons/yr

[4] CO_2e emissions based on GWPs for each greenhouse gas pollutant
CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{753 \text{ lb}}{\text{hr}} \times 1 + \frac{0.03 \text{ lb}}{\text{hr}} \times 21 + \frac{6.11\text{E-03 lb}}{\text{hr}} \times 310$ = 756 lb/hr

Per 40 CFR 98 - *Mandatory Greenhouse Gas Reporting*, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials

CO_2	1
CH_4	21
N_2O	310

Thermal Oxidizer Process GHG Potential Emission Calculations

FIN	EPN	Source Name	Total Molar Flow for CO_2 [1] (lbmol/hr)	Annual Hours of Operation (hr/yr)	Hourly Emissions for CO_2 [2] (lb/hr)	Annual Emissions for CO_2 [3] (tpy)
TO1	TO1	Amine Unit / Thermal Oxidizer 61	1,550.32	8,760	68,214	298,778
TO2	TO2	Amine Unit / Thermal Oxidizer 62	1,550.32	8,760	68,214	298,778
TO3	TO3	Amine Unit / Thermal Oxidizer 63	1,550.32	8,760	68,214	298,778
				Total CO_2 Emissions	**204,643**	**896,334**

11736 scfm
704160 scf/hr
1828.987

[1] Total molar flow for carbon dioxide obtained from Anguil Environmental Systems Thermal Oxidizer Proposal dated September 28, 2011

[2] Hourly Emissions (lb/hr) = Total Molar Flow (lbmol/hr) * Molecular Weight of CO_2

$$\text{EPN TO1 } CO_2 \text{ Hourly Emissions (lb/hr)} = \frac{1{,}550.32 \text{ lb mol}}{\text{hr}} \cdot \frac{44 \text{ lb}}{\text{lbmol}} = 68{,}214 \text{ lb/hr}$$

[3] Annual Emissions (tpy) = Hourly Emissions (lb/hr) * Annual Operating Hours (hrs/yr) * 1 / 2,000 (ton/lb)

$$\text{EPN TO1 } CO_2 \text{ Annual Emissions (tpy)} = \frac{68{,}214 \text{ lb}}{\text{hr}} \cdot \frac{8{,}760 \text{ hr}}{\text{yr}} \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 298{,}778 \text{ tpy}$$

Thermal Oxidizer Combustion Emissions

Parameter	Units	Amine Unit / Thermal Oxidizer 61	Amine Unit / Thermal Oxidizer 62	Amine Unit / Thermal Oxidizer 63
EPN	-	TO1	TO2	TO3
Rated Capacity [1]	MMBtu/hr	5	5	5
Hours of Operation per Year	hrs/yr	8,760	8,760	8,760
Natural Gas Potential Throughput [2]	scf/yr	42,607,004	42,607,004	42,607,004
Natural Gas High Heat Value (HHV) [3]	MMBtu/scf	0.001	0.001	0.001

[1] Per AP-42 Table 3.3-1 Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines Brake Specific Fuel Consumption Factor = 7,000 BTU/hp-hr

[2] Natural gas throughput is based on heat capacity of the unit, hours of operation and the fuel's high heating value

[3] High heating value for No 2 Fuel Oil and Natural Gas obtained from 40 CFR Part 98, Subpart C, Table C-1

GHG Emission Factors for Natural Gas

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	53.020	kg CO_2/MMBtu
CH_4 [2]	0.001	kg CH_4/MMBtu
N_2O [2]	0.0001	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Natural Gas

[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for Natural Gas

GHG Potential Emission Calculations for Combustion of Natural Gas

EPN	Description	Fuel Type	Tier Used	Hourly Emissions [1,2] (lb/hr) CO_2	CH_4	N_2O	CO_2e [4]	Annual Emissions [3] (tons/yr) CO_2	CH_4	N_2O	CO_2e [4]
TO1	Amine Unit / Thermal Oxidizer 61	Natural Gas	Tier 1	584	0.01	1.10E-03	585	2,560	4.83E-02	4.83E-03	2,562
TO2	Amine Unit / Thermal Oxidizer 62	Natural Gas	Tier 1	584	0.01	1.10E-03	585	2,560	4.83E-02	4.83E-03	2,562
TO3	Amine Unit / Thermal Oxidizer 63	Natural Gas	Tier 1	584	0.01	1.10E-03	585	2,560	4.83E-02	4.83E-03	2,562
			Total	1,753.32	0.03	3.31E-03	1,755	7,679.53	0.14	0.01	7,687
			Total CO_2e Emissions [4]	-	-	-	1,755	-	-	-	7,687

[1] CO_2 emissions from No 2 Fuel Oil and Natural Gas combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.
CH_4 and N_2O emissions No.2 Fuel Oil and Natural Gas combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.
Hourly Emissions (lb/hr) = Emission Factor (kg /MMBtu) x Rated Capacity (MMBtu/hr) x Conversion factor (lb/kg)

Example CO_2 Hourly Emissions (lb/hr) = $\frac{53.02 \text{ kg CO2}}{\text{MMBtu}} \times \frac{5 \text{ MMBtu}}{\text{hr}} \times \frac{2.2046 \text{ lb}}{\text{kg}}$ = 584 lb/hr

[2] kg to lb conversion 2.2046 lb/kg

[3] Annual Emissions (short tons/yr) = Annual Emissions (lb/hr) x Annual Operating Hours (hr/yr) / Conversion factor (lb/short tons)

Example CO_2 Annual Emissions (tons/yr) = $\frac{584 \text{ lb}}{\text{hr}} \times \frac{8760 \text{ hr}}{\text{yr}} \times \frac{\text{tons}}{2000 \text{ lb}}$ = 2560 tons/yr

[4] CO_2e emissions based on GWPs for each greenhouse gas pollutant
CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{584 \text{ lb}}{\text{hr}} \times 1 + \frac{0.01 \text{ lb}}{\text{hr}} \times 21 + \frac{1.10\text{E-03 lb}}{\text{hr}} \times 310$ = 585 lb/hr

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials

CO_2	1
CH_4	21
N_2O	310

Thermal Oxidizer Total GHG Potential Emission

FIN	EPN	Source Name	Hourly Emissions (lb/hr) CO_2 [1]	CH_4 [2]	N_2O [2]	CO_2e [3]	Annual Emissions (tons/yr) CO_2 [1]	CH_4 [2]	N_2O [2]	CO_2e [3]
TO1	TO1	Amine Unit / Thermal Oxidizer 1	68,799	0.01	1.10E-03	68,799	301,338	4.83E-02	4.83E-03	301,341
TO2	TO2	Amine Unit / Thermal Oxidizer 2	68,799	0.01	1.10E-03	68,799	301,338	4.83E-02	4.83E-03	301,341
TO3	TO3	Amine Unit / Thermal Oxidizer 3	68,799	0.01	1.10E-03	68,799	301,338	4.83E-02	4.83E-03	301,341
		Total	206,396	0.03	0.00	206,397.61	904,014	0.14	0.01	904,022
		Total CO_2e Emissions [4]	-	-	-	206,398	-	-	-	904,022

[1] CO_2 Emissions are the sum of Thermal Oxidizer combustion and process GHG Emissions
Example CO_2 Hourly Emission Calculations (lb/hr) = $\frac{68{,}214 \text{ lb}}{\text{hr}} + \frac{584 \text{ lb}}{\text{hr}}$ = 68,799 lb/hr

[2] CH_4 and N_2O Emissions are the from Thermal Oxidizer combustion only
[4] CO_2e emissions based on GWPs for each greenhouse gas pollutant
CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Annual Emission Rate (lb/hr) = $\frac{68799 \text{ lb}}{\text{hr}} \times 1 + \frac{0.01 \text{ lb}}{\text{hr}} \times 21 + \frac{1.10\text{E-03 lb}}{\text{hr}} \times 310$ = 68,799 lb/hr

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials

CO_2	1
CH_4	21
N_2O	310

Flare Design and Operational Parameters

Flare Parameters [1]	Value	Units
Pilot Gas Flow	1,870,000	Btu/hr
Annual Pilot Gas Flow	16,381	MMBtu/yr
Molecular Weight	18.3	lb/lbmol
Heating Value of Flare Gas	1,080	Btu/scf
Flare Design Basis	945,000	lb/hr
Flare Design Basis	19,984,426	scf/hr
Annual volumetric flow rate based on MSS events	167,212,461	scf/yr [2]
Annual mass flow rate based on MSS events	3,953	tpy [3]

[1] Data obtained from Callidus Flare Proposal 10/3/2011

[2] Flow rate (scf/yr) calculated by Mr. Ruben Velasquez (Atkins) submitted to Mr. John Barrientez via email on October 24,2011. The total flow is equivalent to one start-up and shut-down event each year.

[3] Annual Mass Flow rate Based on MSS Events (tpy) = Volumetric Flow Rate (scf/yr) * Molecular Weight (lb/mol) * 1 / 2,000 (ton/lb) / 387 (scf/lbmol)

Annual mass flow rate based on MSS events (tpy) = $\frac{167{,}212{,}461 \text{ scf}}{\text{yr}} \left| \frac{18.3 \text{ lb}}{\text{lbmol}} \right| \frac{1 \text{ ton}}{2{,}000 \text{ lb}} \left| \frac{\text{lbmol}}{387 \text{ scf}} \right.$ = 3,953 tpy

GHG Emission Factors - Natural Gas Combustion

Greenhouse Gas	Emission Factor [1] (kg/MMBtu)
CO_2	53.02
CH_4	1.0E-03
N_2O	1.0E-04

[1] Per 40 CFR Part 98 dated December 17, 2010, Table C-1 of Subpart C - *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel* and Table C-2 of Subpart C - *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*. Emission factors for natural gas (unspecified heat value, weighted U.S. average) are used.

GHG Emission Rates From the Flare

Heat Input Capacity [1] (MMBtu/yr)	Annual Emissions [2, 3] (tons/yr) CO_2	CH_4	N_2O	CO_2e [4]
196,970.66	11,512	0.22	0.02	11,523

[1] Heat Input Capacity (MMBtu/yr) = Annual Natural Gas Flowrate (scf/yr) * Higher Heating Value (Btu/scf) * 1 / 1,000,000 (Btu/MMBtu) + Pilot Gas Annual Flowrate (MMBtu/yr)

Heat Input Capacity (MMBtu/yr) = $\frac{167{,}212{,}461 \text{ scf}}{\text{yr}} \left| \frac{1{,}080 \text{ Btu}}{\text{scf}} \right| \frac{\text{MMBtu}}{1{,}000{,}000 \text{ Btu}} + \frac{16{,}381 \text{ MMBtu}}{\text{yr}}$ = 196,971 MMBtu/yr

[2] Annual Emissions (tons/yr) = Emission Factor (kg/MMBtu) * Heat Input Capacity (MMBtu/yr) * 0.001102 (ton/kg)

Annual Emissions of CO_2 (tons/yr) = $\frac{53.02 \text{ kg}}{\text{MMBtu}} \left| \frac{196{,}970.66 \text{ MMBtu}}{\text{yr}} \right| \frac{0.001102 \text{ tons}}{\text{kg}}$ = 11,511.74 tons/yr

[3] kg to lb conversion 0.0011023 ton/kg

[4] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO_2e Annual Emission Rate (tons/yr) = CO_2 Emission Rate (tons/yr) x CO_2 GWP + CH_4 Emission Rate (tons/yr) x CH_4 GWP + N_2O Emission Rate (tons/yr) x N_2O GWP

Example CO_2e Annual Emission Rate (tons/yr) = $\frac{11{,}512 \text{ tons}}{\text{yr}} \left| 1 \right. + \frac{2.17\text{E-01 tons}}{\text{yr}} \left| 21 \right. + \frac{2.17\text{E-02 tons}}{\text{yr}} \left| 310 \right.$ = 11,523 tons/yr

Per 40 CFR 98 - *Mandatory Greenhouse Gas Reporting*, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials

CO_2	1
CH_4	21
N_2O	310

Flare Design and Operational Parameters

Flare Parameters [1]	Value	Units
Pilot Heat Input[2]	170,000	Btu/hr
Annual Pilot Heat Input	1,489	MMBtu/yr
Heating Value of Flare Gas	2,695	Btu/scf
Waste Gas Flow Rate	379,981	scf/hr
Waste Gas Annual Venting Basis	8	hrs/yr

[1] Data obtained from Callidus Flare Proposal dated 9/12/2011.
[2] Based on two pilots each 85,000 Btu/hr.

GHG Emission Factors - Natural Gas and Propane Combustion

Greenhouse Gas	Natural Gas Emission Factors [1] (kg/MMBtu)	Propane Emission Factor [2] (kg/MMBtu)
CO_2	53.02	61.46
CH_4	1.0E-03	3.00E-03
N_2O	1.0E-04	6.00E-04

[1] Per 40 CFR Part 98 dated December 17, 2010, Table C-1 of Subpart C - *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel* and Table C-2 of Subpart C - *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*.
[2] Per 40 CFR Part 98 dated December 17, 2010, Table C-1 of Subpart C - *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel* and Table C-2 of Subpart C - *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*.

GHG Emission Rates From the Flare

Annual Pilot Heat Input (MMBtu/yr)	Waste Gas Heat Input [1] (MMBtu/yr)	Annual Emissions [2,3] (tons/yr) CO_2	CH_4	N_2O	CO_2e [4]
1,489	8,192.39	641.87	2.87E-02	5.58E-03	644.21

[1] Waste Gas Heat Input (MMBtu/yr) = Waste Gas Flowrate (scf/hr) * Heating Value of Flare Gas (Btu/scf) * 1 / 1,000,000 (Btu/MMBtu) * Waste Gas Annual Venting Basis (hrs/yr)

$$\text{Heat Input Capacity (MMBtu/yr)} = \frac{379{,}981\ \text{scf}}{\text{hr}} \left| \frac{2{,}695\ \text{Btu}}{\text{scf}} \right| \frac{\text{MMBtu}}{1{,}000{,}000\ \text{Btu}} \left| \frac{8\ \text{hrs}}{\text{yr}} \right. = 8{,}192.39\ \text{MMBtu/yr}$$

[2] Annual Emissions (tons/yr) = Natural Gas Emission Factor (kg/MMBtu) * Annual Pilot Heat Input (MMBtu/yr) * 0.001102 (ton/kg) + Propane Emission Factor (kg/MMBtu) * Waste Gas Heat Input (MMBtu/yr) * 0.001102 (ton/kg)

$$\text{Annual Emissions of } CO_2 \text{ (metric tons/yr)} = \frac{53.02\ \text{kg}}{\text{MMBtu}} \left| \frac{1{,}489.20\ \text{MMBtu}}{\text{yr}} \right| \frac{0.001102\ \text{tons}}{1\ \text{kg}} + \frac{61.46\ \text{kg}}{\text{MMBtu}} \left| \frac{8{,}192.39\ \text{MMBtu}}{\text{yr}} \right| \frac{0.001102\ \text{tons}}{1\ \text{kg}} = 641.87\ \text{tons/yr}$$

[3] kg to lb conversion 0.001102 ton/kg
[4] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO_2e Annual Emission Rate (tons/yr) = CO_2 Emission Rate (tons/yr) x CO_2 GWP + CH_4 Emission Rate (tons/yr) x CH_4 GWP + N_2O Emission Rate (tons/yr) x N_2O GWP

$$\text{Example } CO_2e \text{ Annual Emission Rate (tons/yr)} = \frac{641.87\ \text{tons}}{\text{yr}} \left| 1 \right. + \frac{2.87\text{E-}02\ \text{tons}}{\text{yr}} \left| 21 \right. + \frac{5.58\text{E-}03\ \text{tons}}{\text{yr}} \left| 310 \right. = 644.21\ \text{tons/yr}$$

Per 40 CFR 98 - *Mandatory Greenhouse Gas Reporting*, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials

CO_2	1
CH_4	21
N_2O	310

Freeport LNG Development, L.P.
Pretreatment Facility

FIN/EPN: FUG-TREAT

Pretreatment VOC Fugitives

Components [1]	Phase	Oil and Gas Production Factors [1] (lb/hr/component)	Actual Component Count [2]	Assumed % CH_4 content	28 MID Credit % [1]	Controlled VOC Emission Rates [3,4] (lb/hr)	Controlled VOC Emission Rates [3,4] (tpy)
Valves	Gas/ Vapor	0.00992	2,947	91.40	97	0.80	3.51
	Light Liquid	0.0055	697	91.40	97	0.11	0.46
	Heavy Liquid	0.0000185	434	91.40	0	7.34E-03	0.03
Pressure Relief Valves	Gas/Vapor	0.0194	115	91.40	97	0.06	0.27
Pump Seals	Light Liquid	0.02866	9	91.40	93	0.02	0.07
	Heavy Liquid	0.00113	5	91.40	0	5.16E-03	0.02
Flanges/Connectors	Gas/ Vapor	0.00086	6,382	91.40	30	3.51	15.38
	Light Liquid	0.000243	1,424	91.40	30	0.22	0.97
	Heavy Liquid	0.00000086	1,161	91.40	30	6.39E-04	2.80E-03
Compressor Seals	Gas/Vapor	0.0194	24	91.40	95	0.02	0.09
Open Ended Lines	All	0.00441	0	91.40	97	--	--
Sampling Connections	All	0.033	9	91.40	97	8.14E-03	0.04
TOTAL EMISSIONS (CH_4)						**4.76**	**20.85**
TOTAL EMISSIONS (CO_2e) [5]						**99.96**	**437.82**

[1] Values obtained from *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, Air Permits Division, TCEQ* (October 2000).

[2] Data provided by Mr. Ruben Velasquez (Atkins) to Ms. Melissa Dakas (Trinity Consultants) via email on October 7, 2011 and October 13, 2011.

[3] Hourly Controlled CH_4 Emission Rate (lb/hr) = Oil and Gas Factor * Component Count * (%CH_4 content in LNG / 100)*(1-28MID Credit % / 100)

Hourly Emission Rate for Valves from Gas/Vapor (tpy) = $\frac{9.92\text{E-03 MMbtu}}{\text{hr/component}} \Big| 2{,}947 \Big| \frac{91.40}{100} \Big| \frac{97.00}{100}$ =

[4] Annual Controlled CH_4 Emission Rate (tpy) = Hourly CH_4 Emission Rate (lb/hr) * 8,760 (hr/yr) / 2,000 (lb/ton)

Annual Emission Rate for Valves from Gas/Vapor (tpy) = $\frac{0.8\text{ lb}}{\text{hr}} \Big| \frac{8{,}760\text{ hr}}{\text{yr}} \Big| \frac{1\text{ ton}}{2{,}000\text{ lb}}$ = 3.51 tpy

[5] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO_2e Hourly Emission Rate (lb/hr) = CH_4 Emission Rate (lb/hr) x CH_4 GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{4.76\text{ lb}}{\text{hr}} \Big| 21$ = 99.96 lb/hr

Per 40 CFR 98 - *Mandatory Greenhouse Gas Reporting*, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21

Liquefaction Fugitives

Components	Phase	Oil and gas Production Factors [1] (lb/hr/component)	Actual Component Count [2]	Assumed % CH_4 content	28 MID Credit %	Controlled VOC Emission Rates[3,4] (lb/hr)	(tpy)
Valves	Gas/ Vapor	0.0099	1,509	91.40	97	4.10E-01	1.79
Pressure Relief Valves	Gas/Vapor	0.0194	60	91.40	97	3.19E-02	0.14
Pump Seals	Light Liquid	0.0287	3	91.40	93	5.51E-03	0.02
Flanges/Connectors	Gas/ Vapor	0.0009	3,017	91.40	30	1.74E+00	7.61
Compressor Seals	Gas/Vapor	0.0194	8	91.40	95	7.09E-03	0.03
Open Ended Lines	All	0.0040	0	91.40	97	0.00E+00	0.00
Sampling Connections	All	0.0330	9	91.40	97	8.14E-03	0.04
Other	All	0.0194	0	91.40	97	0.00E+00	0.00
TOTAL EMISSIONS (CH_4)						**2.20**	**9.63**
TOTAL EMISSIONS (CO_2e)[5]						**46.19**	**202.31**

[1] Values obtained from *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, Air Permits Division, TCEQ* (10/00).

[2] Data provided by Mr. Ruben Velasquez (Atkins) to Ms. Melissa Dakas (Trinity Consultants) via email on October 7, 2011.

[3] Hourly Controlled CH_4 Emission Rate (lb/hr) = Oil and Gas Factor * Component Count * (%CH_4 content in LNG / 100)*(1-28MID Credit % / 100)

Hourly Emission Rate for Valves from Gas/Vapor (tpy) = $\frac{9.90E\text{-}03 \text{ lb}}{\text{MMBtu}} \;\Big|\; 1509 \;\Big|\; \frac{91.40}{100} \;\Big|\; \frac{97.00}{100}$ = 0.41 lb/hr

[4] Annual Controlled CH_4 Emission Rate (tpy) = Hourly CH_4 Emission Rate (lb/hr) * 8,760 (hr/yr) / 2,000 (lb/ton)

Annual Emission Rate for Valves from Gas/Vapor (tpy) = $\frac{4.10E\text{-}01 \text{ lb}}{\text{hr}} \;\Big|\; \frac{8{,}760 \text{ hr}}{\text{yr}} \;\Big|\; \frac{1 \text{ ton}}{2{,}000 \text{ lb}}$ = 1.79 tpy

[5] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO_2e Hourly Emission Rate (lb/hr) = CH_4 Emission Rate (lb/hr) x CH_4 GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{2.20 \text{ lb}}{\text{hr}} \;\Big|\; 21$ = 46.19 lb/hr

Per 40 CFR 98 - *Mandatory Greenhouse Gas Reporting*, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials

CO_2	1
CH_4	21

Liquefaction Project SF_6 Inventory

Area	Liquefaction	Liquefaction	Pretreatment
Breaker Rating	138 kV	69 kV	138 kV
Number of Breakers	13	27	6
SF_6 lb per Breaker	163	132	163

Liquefaction Project SF_6 GHG Emissions

Component	Liquefaction		Pretreatment	
Total Project SF_6 Capacity (lb) [1]	5683	lb	978	lb
Leak Rate	0.50%	% per year	0.50%	% per year
Potential Annual Leakage [2]	28.42	lb SF_6/year	4.89	lb SF6/year
	0.014	ton/year.	0.002	ton/year.
	0.003	lb/hr	0.001	lb/hr
Annual CO_2e emissions [3]	339.56	ton/year.	58.44	ton/year.
	77.52	lb/hr	13.34	lb/hr

[1] Total Project SF_6 Capacity (lb) = ∑(Number of breakers * SF_6 lb per Breaker)

Example, Total Project SF_6 Capacity (lb) for Liquefaction = $\frac{13 \text{ Breaker}}{} \Big| \frac{163 \text{ lb SF6}}{\text{Breaker}}$ + $\frac{27 \text{ Breaker}}{} \Big| \frac{132 \text{ lb SF6}}{\text{Breaker}}$ = 5683 lb

[2] Potential Annual Leakage calculated as follows

Total as lb SF_6/year = Total Project SF_6 capacity (lb) * Leak Rate (% per year)

Example calculation for Liquefaction (lb SF_6/year) = $\frac{5683 \text{ lb}}{} \Big| \frac{0.005\ \%}{\text{yr}}$ = 28.42 lb SF6/year

Total as ton/year = Total Potentia Annual Leakage (lb SF_6/year) / 2000 (lb/ton)

Example calculation for Liquefaction (ton SF_6/year) = $\frac{28.42 \text{ lb SF6}}{\text{year}} \Big| \frac{\text{ton}}{2000 \text{ lb}}$ = 0.014 ton/year

Total as lb/hr = Total Potentia Annual Leakage (lb SF_6/year) / Annual Operating hours (hr/yr)

Example calculation for Liquefaction (lb SF_6/hr) = $\frac{28.42 \text{ lb SF6}}{\text{year}} \Big| \frac{\text{yr}}{8{,}760 \text{ hr}}$ = 0.003 lb/hr

[3] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO_2e Annual Emission Rate (ton/yr) = SF_6 Emission Rate (ton/yr) x SF_6 GWP

Example CO_2e Annual Emission Rate (ton/yr) = $\frac{0.014 \text{ ton}}{\text{year}} \Big| \frac{23900}{}$ = 339 56 ton/yr

Per 40 CFR 98 - *Mandatory Greenhouse Gas Reporting* , Subpart A, Table A-1

CO_2	1
SF_6	23,900

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Appendix B

Heating Medium Heater Data Sheet

Thermal Fluid System Datasheet

Customer Name	*Freeport LNG*	*Project Name*	*Pretreatment Facility*
Date completed	*December 8, 2011*	*Project Location*	*Stratton Ridge, TX*
Revision number	*A*	*Sales Engineer*	*Charlie Wadlington*

Heat Input	56	MMBTU/hr	Heater Model Number	HC2-50.0-H-SF	
Heater Type	HC2		Heater Configuration	Horizontal	
System Flow Rate	700	gal / min.	Fluid Pressure Drop	22	lb / in²(d)
Heater Flow Rate	3,000	gal / min.	Flue Gas Pressure Drop	6.6	in W.C.
System Bypass	2,300	gal / min.	Average Heat Flux	10,279	Btu / hr / ft2
Heater Bypass	0	gal / min.	Radiant Zone Heat Flux	23,686	Btu / hr / ft2
Thermal Fluid	Dowtherm Q		Maximum Film Temperature	671	°F
Process Supply Temperature	625	°F	Inner Coil Velocity	11	ft / sec
Heater Outlet Temperature	625	°F	Outer Coil Velocity	8	ft / sec
Process Return Temperature	276	°F	Thermal Efficiency	80%	% LHV Basis

Fuel Type	Gas		Selected Burner Make	Coen / Todd Combustion	
Combustion Air Preheat	No		Burner Model Selected	QLN-II	
Efficiency with Preheat	N/A	% LHV Basis	Steady State Firing Rate (HHV Basis)	77,211,247	Btu / hr
Oxygen Trim	No		Burner Design Margin	10%	
Fully Metered / Cross Limited	Yes		Design Firing Rate (HHV Basis)	84,932,372	Btu / hr
Low NOx Required	Yes		Combustion Air Design Temperature	244	°F
BMS Type	Standard		Available Fuel Pressure From Customer	10	lb / in²(g)
Combustion Control Type	Standard		Design Fuel Flow Rate	83,586	(std)ft³ / hr
Control Panel Location	Heater Mounted		Burner Duty Cycle	Continuous	
NOx Required (if any)	5	ppm	Fuel Train Location	Heater Mounted	
CO Required (if any)	25	ppm	Fuel Train / BMS Code Compliance	NFPA 87-11	
Gas Consumption @ Steady State	75,987	(std)ft³ / hr	Fuel Train Size	4	in.
Air Consumption @ Steady State	25,986	(act)ft³ / min	Fuel Train Type	Sigma Thermal Standard	
Gas Consumption @ High Fire	83,586	(std)ft³ / hr	Fuel Train Construction	NPT	
Air Consumption @ High Fire	28,585	(act)ft³ / min	Flue Gas Velocity	66	ft / sec
Exhaust Gas Flow Rate	49,069	(act)ft³ / min	Exhaust Gas Temperature	760	°F
Stack Diameter	48	in	Stack Height	30	ft

Thermal Fluid System Datasheet

Maximum Ambient Temperature	100	°F	Control Panel Area Classification	Class I Div. II	
Minimum Ambient Temperature	-20	°F	Skid Area Classification	Class I Div. II	
Elevation (above mean sea level)	0	ft	Wiring Standards	Sigma Thermal Standard	
Motor Requirements	Standard Efficiency TEFC		Electrical Code of Construction	Sigma Thermal Standard	
Instrumentation	Sigma Thermal Standard		Control Panel Certification	UL	
Motor Starters	By Others		Primary Voltage	460V / 3 / 60Hz	
Minimum Electrical Enclosures Rating	4X		Control Voltage	120V / 1 / 60Hz	
Paint Colors	Sigma Thermal Standard		Overall Paint Specification	Sigma Thermal Standard	

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Appendix C

Anguil Proposal to Freeport LNG Dated June 8, 2011

Proposed Regenerative Thermal Oxidizers

Anguil Environmental Systems, Inc.
Regenerative Thermal Oxidizer

Date: June 8, 2012
Proposal #: AES-110208C

Prepared for:

Mr. Steve Chafin
Chief Process Engineer
Freeport LNG
333 Clay Street, Suite 5050
Houston, Texas 77002-4173

Office: 713-333-4257
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Proposal For: Freeport LNG

AES-110208C

"Our goal is to provide solutions today which help our customers remain profitable tomorrow"
– Gene Anguil / Founder and CEO

Background:
- Founded in 1978
- Second generation family owned and operated
- Headquartered in Milwaukee, WI, USA with offices in Asia and Europe
- Over 1,650 oxidizers and countless heat recovery systems installed on six continents in a wide variety of industries

Company Size and Make-up:
- Annual sales in excess of $25 million
- In-house engineering staff consists of chemical, mechanical and electrical engineers
- Highly motivated employees who enjoy profit sharing and a rewarding work environment

What Makes Anguil Unique?
- Regulatory compliance is guaranteed
- Broad range of technology solutions that ensure an unbiased equipment selection
- Quality assurance program with complete factory acceptance testing prior to shipment
- An established safety program with continuous training for Anguil technicians
- Equipment is designed in Solidworks, ensuring accuracy and rapid completion

Products:

Air pollution control systems...
- Regenerative Thermal Oxidizers (RTO)
- Catalytic, Recuperative and Direct-Fired Thermal Oxidizers
- Concentrator systems
- Permanent Total Enclosures

...for VOC, HAP and odor abatement

Heat and energy recovery systems...
- Air-to-air heat exchangers
- Air-to-liquid heat exchangers
- Heat-to-power
- Energy Evaluations

...for improved efficiency and reduced operating costs

Aftermarket:

Service and Maintenance...
- 24/7 Emergency service response
- Operating cost reviews
- System upgrades and retrofits
- Spare parts and component packages
  - Preventive Maintenance Evaluations (PME)

... on any make or model, regardless of original manufacturer

Partial List of Satisfied Customers:
Boeing, Dow Chemical, Northrop Grumman, ExxonMobil, Johnson and Johnson, Peterbilt, Qualcomm, Rexam Beverage, Silgan Containers, Wyeth

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Table of Contents

***Note: This proposal contains confidential and proprietary information of Anguil Environmental Systems, Inc. and is not to be disclosed to any third parties without the express prior written consent of Anguil.**

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Executive Summary

1. Equipment Description

Freeport LNG has requested a proposal for an oxidizer for the destruction of VOCs from their facility located in Freeport, TX. The VOCs are in an inert CO_2 stream and will be combined with preheated fresh air, to prevent water and sulfuric/sulfurous acid condensation, prior to being delivered to a new Regenerative Thermal Oxidizer (RTO). The RTO will be sized for a total flow of 20,000 SCFM.

Wetted components of the oxidizer have been upgraded to either 316L Stainless Steel or vinyl ester coated carbon steel to protect against carbonic acid corrosion and sulfur corrosion associated with oxidation of hydrogen sulfide in the process stream. The RTO is designed with high heat recovery to reduce operating cost. **To reduce NOx emissions, a Maxon Kinedizer burner is used in lieu of a Maxon Kinemax burner. This allows the unit to guarantee 0.04 lb NOx/MM Btu fired.**

2. Facility to be Controlled

Freeport LNG facility in Freeport, TX

3. Processes Controlled

LNG facility

4. RTO Energy Recovery

95% Thermal Energy Recovery to minimize gas usage

5. Proposed Equipment

One Model 200 (20,000 SCFM) Regenerative Thermal Oxidizer (RTO)

6. Anguil Benefits

* Seamless integration with the current process
* **<u>True</u>** 95% nominal heat transfer efficiency, adjusted for CO_2 content and altitude
* Fully automated PLC based controls
* Modem for remote diagnostics
* Field Tested and proven technology
* Full equipment warranty
* Factory test prior to shipment
* 24 hour service support

7. Results

* Anguil guarantees the conversion efficiency of 99% or an outlet concentration of 20 ppmv as C1 (methane), whichever is less stringent per EPA Method 25A.

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Customer Process Specifications

- Process Information*:

Property	
Temperature (°F)	104
Pressure (psig)	13.60
Vapor Fraction	1
Volume Flow (MMSCFD)	16.900
Compound	**Amine Reflux Drum OVHD (mol%)**
Water	3.78506
Nitrogen	0.00028
Hydrogen Sulfide**	0.00533
Carbon Dioxide	95.92050
Methane	0.26170
Ethane	0.01128
Propane	0.00146
i-Butane	0.00039
n-Butane	0.00034
i-Pentane	0.00031
n-Pentane	0.00031
Hexanes	0.00017
Heptanes	0.00008
Octanes	0.00005
Nonanes	0.00008
Carbonyl Sulfide	0.00001
Mercaptans	0.01099
Cyclohexane	0.00003
Benzene	0.00073
Toluene	0.00070
Xylene	0.00031
Amine Solution	0.00000
Total Process Gas	11,736 SCFM
Process Heat Release	2.95 Btu/scf (20,035 Btu/lb)
Fresh air for Oxidation of VOCs	389 SCFM
Fresh Air for 3% Stack O_2	2,021 SCFM
Recirculated Oxidation Chamber Flow (3% O_2) for Inlet Preheat	2,419 SCFM
Total Preheated Fresh Air Flow	4,829 SCFM
Inlet Flow to Oxidizer	16,565 SCFM
Maximum Allowable Process Heat Release	19.50 Btu/scf (20,035 Btu/lb in 11,736 SCFM process gas)
Total Preheated Fresh Air for Oxygen and Temperature Control	8,264 SCFM
Flow to Oxidizer	20,000 SCFM
RTO System Design	Model 200 RTO: 20,000 SCFM

* Assumed no halogenated or chlorinated compounds are present.
**Anguil's experience with oxidizers in the vicinity of this location shows that the oxidizer should be designed for trace amounts of Hydrogen Sulfide in the process stream. Due to corrosion associated with the products of sulfur combustion (sulfurous/sulfuric acid), further materials of construction consideration may be required for trace amounts of Hydrogen Sulfide above 1 ppmv in the process stream

• Elevation:	14 FASL
• Barometric Pressure:	14.0 psia
• Ambient Temperature Range:	-20°F to 110°F
• Design Wind Load:	7 mph (Exposure "C")
• Facility Operating Schedule:	24 hr/day, 7 days/wk, 52 wk/yr
• Facility Power:	460 V / 60 Hz / 3 Ph
• Fuel Source:	Fuel Gas
• Performance Requirements:	99% VOC Destruction
• RTO location on Site:	Outdoors

Note: Equipment has been designed and sized based on these customer parameters.

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Design Specifications

Size and Weight

- Maximum Flow (Includes Dilution Air): 20,000 SCFM
- Approximate Footprint: 41' x 23'
- Approximate Weight: 90,000 lb
- Stack Height: 30'
- Stack Diameter: 44"
- Oxidizer Control Panel Location: Skid Mounted NEMA 3R Control Panel
- Suggest Foundation Size: 47' x 26'

Utilities Required

- Fuel Requirements: 5 psig
- Electrical Power: 460V / 60 Hz / 3 Ph
- Required Compressed Air: 80-100 psig (-40°F dewpoint) 5-10 SCFM

Operation Information

- Oxidizer Guarantees: 99% VOC destruction efficiency or an outlet concentration of 20 ppmv as C1 (methane), whichever is less stringent per EPA Method 25A.

  NOx: 0.04 lbs / MM BTU burner firing rate

  CO: 50 ppmv, uncorrected for O_2 conc.

  SOx: 0.6 lbs / MMCF of gas combustion

  PM: 5 lbs / MMCF of gas combustion

- Nominal Heat Transfer Efficiency: 95%
- Recycle Fan Draft Design: Forced
- System Fan HP: 200 HP
- Combustion Fan HP: 7.5 HP
- Burner Installed Maximum Capacity: 5.0 MM BTU/hr
- Operating Set Point: 1550-1700°F

***Note: All weights, dimensions, horsepower ratings, burner sizing, and specific engineering details within the proposal are approximate and will be confirmed by Anguil Environmental following order placement.**

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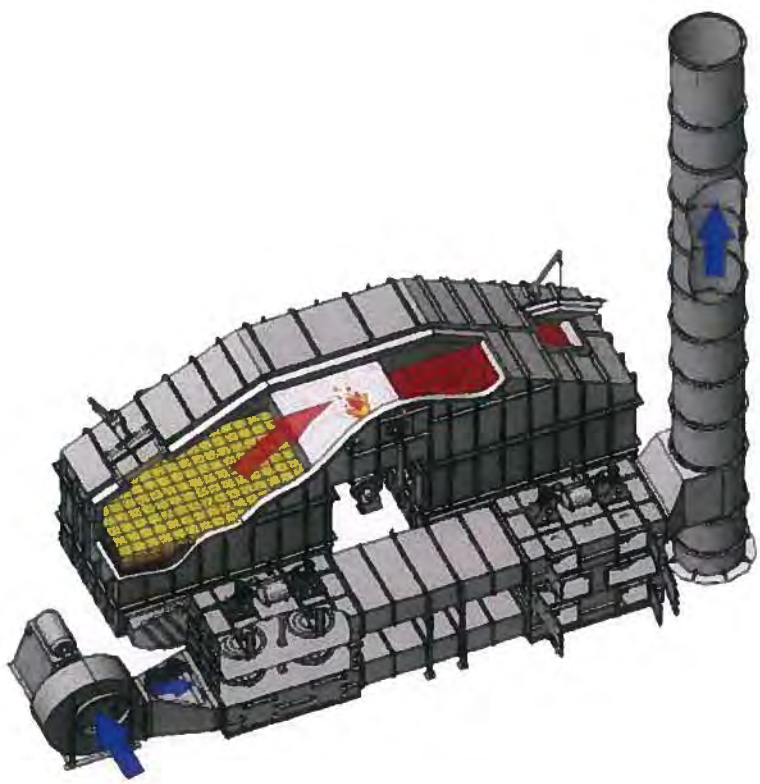
Standard Equipment Specifications

The Anguil Regenerative Thermal Oxidizer (RTO) destroys Hazardous Air Pollutants (HAPs), Volatile Organic Compounds (VOCs) and odorous emissions that are discharged from industrial processes. Emission destruction is achieved through the process of high temperature thermal or catalytic oxidation, converting the pollutants to carbon dioxide and water vapor while reusing the thermal energy generated to reduce operating costs.

How the RTO Works-

VOC and HAP laden process gas enters the oxidizer through an inlet manifold to flow control, poppet valves that direct this gas into energy recovery chambers where it is preheated. The process gas and contaminants are progressively heated in the ceramic media beds as they move toward the combustion chamber.

Once oxidized in the combustion chamber, the hot purified air releases thermal energy as it passes through the media bed in the outlet flow direction. The outlet bed is heated and the gas is cooled so that the outlet gas temperature is only slightly higher than the process inlet temperature. Poppet valves alternate the airflow direction into the media beds to maximize energy recovery within the oxidizer. The high energy recovery within these oxidizers reduces the auxiliary fuel requirement and saves operating cost. The Anguil oxidizer achieves high destruction efficiency and self-sustaining operation with no auxiliary fuel usage at concentrations as low as 3-4% LEL (Lower Explosive Limit).



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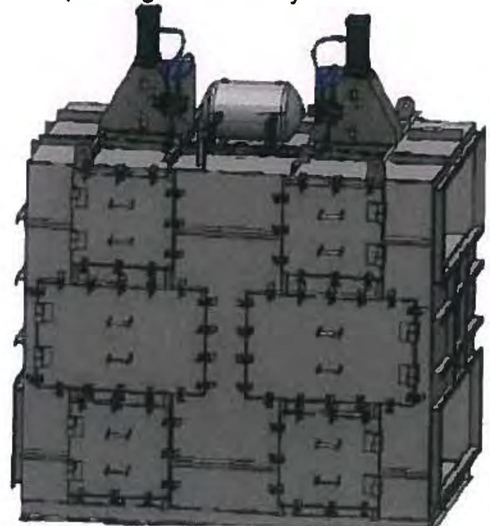
POPPET VALVES

Anguil's poppet valves are uniquely designed to divert high volume process air into and out of the oxidizer, properly balance VOC loading, maintain destruction efficiency and optimize heat recovery. We custom design, manufacture and install these vital components to ensure reliability and trouble free operation. Anguil has several poppet assemblies that have been operating continuously since 1993 and have required nothing but regular maintenance.



SPECIFICATIONS

- **316L Stainless Steel Shaft, Disk & Seat**
- Poppet Box Body: **316L Stainless Steel**
- Cylinder Actuator Supports: 1/4" Plate Steel
- Parker Hannifin Heavy Duty Pneumatic Cylinder:
  90 psi, 10 CFM, -40°F
- Heavy Duty, High Flow, 4-way Parker Hannifin Solenoid Valve
- Bolted Actuator Mountings with Shaft Guarding
- Connecting Duct Work to Fan and Exhaust Stack
- Compressed air Accumulator Tank Included
- End of Stroke Switches
- Solenoid Valve Exhaust Flow Control
- *External insulation of the poppet valves for personnel protection and to prevent water condensation has not been included at this time. Anguil recommends that it will be the most cost effective to insulate onsite during installation.*

FEATURES

- Vertical Shaft
- Double Acting, Three-way Air Flow Design:
- Reliable Metal to Metal Seal:
  1MM+ cycles
- Removable Machined Seats:
  <0.25% leakage at 18" W.C.
- Valve Pressure Drop: Maximum of 2" W.C.
- Rectangular Ports for Inlet/Outlet Ducting
- Removable Actuator Mounting
- Hinged Access Doors with Toggle clips
- Lockout Device with Padlock Provision
- Quiet Operation
- Over Temperature Protection
- Short valve switch distance

ADVANTAGES

Energy Efficient – Compressed air consumption to switch solenoids from closed to open position is minimal
Dependable – Two-disc system minimizes valve switch distance and wear
Ease of Maintenance – Multiple hinged access doors make occasional cleaning and bearing maintenance easy

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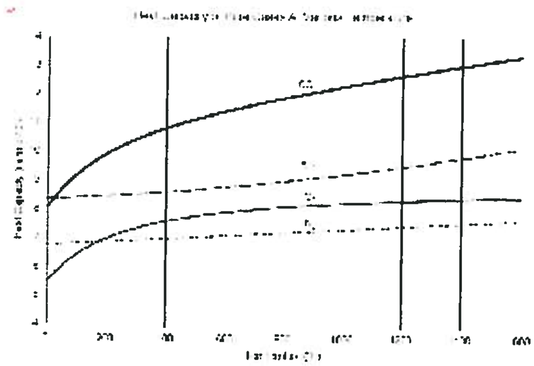
HEAT TRANSFER MEDIA

- Two (2) beds of high temperature chemical porcelain structured heat transfer media
- **Media has been adjusted to account for the high CO_2 content to provide a true 95% thermal efficiency. The heat capacity of CO_2 is higher than that of air (~70% nitrogen) meaning you need more energy to heat up the CO_2. More media would be required to provide more preheat to the incoming CO_2.**
- Ceramic media designed to provide optimum heat transfer surface area
- Media bed for proper air distribution and optimum RTO performance
- Low system pressure drop



BURNER(S)/FUEL TRAIN

- **Maxon Kinedizer Ultra-low NOx burner to achieve 0.04 lb NOx / MM Btu fired**
- Fuel source – Fuel Gas
- Fuel Train fabricated to FM Global specifications
- Service platform and ladder
- 3" burner view port
- Fireye flame safety control with self-checking dynamic UV scanner
- **Carbon steel fuel train, no brass or cast iron**
- **Electric actuated natural gas firing rate valve and blocking valves included**
- ***Optional pricing is given to upgrade to pneumatic actuated natural gas firing rate valve. Upgrade includes a higher class of valve and additional compressed air piping to each actuator.***

COMBUSTION AIR FAN

- Twin City Fan, New York Blower or equal
- Pre-piped and pre-wired
- Inlet filter
- Independent controlled fuel and combustion air valves
- **Electric actuated natural combustion air valve included**
- ***Optional pricing is given to upgrade to pneumatic actuated combustion air valve upgrade. Upgrade includes a higher class of valve and additional compressed air piping to each actuator.***

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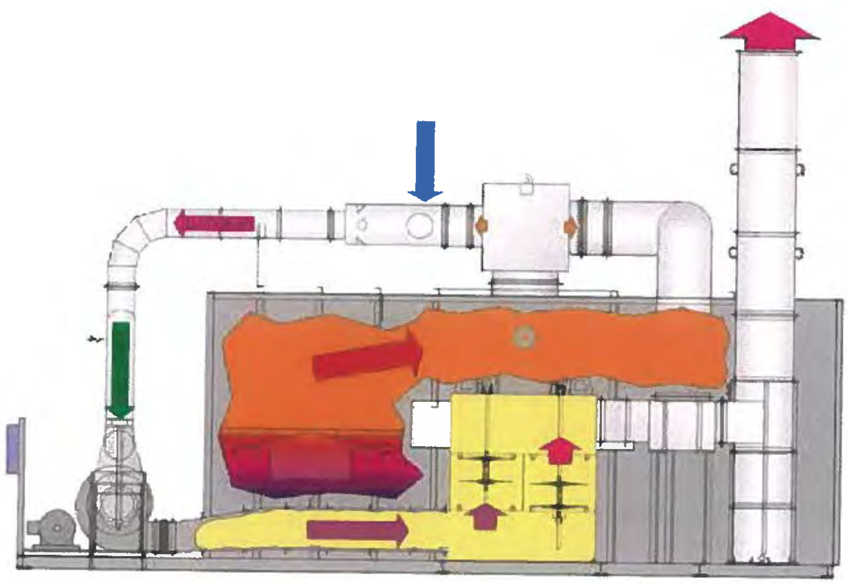
FRESH AIR PREHEAT SYSTEM

Fresh air is used during oxidizer start-up/shut-down, purging during idle time and to provide oxygen for oxidation. Anguil recommends that, during normal operation, the fresh air be preheated above the sulfuric acid dewpoint prior to mixing with the process gas upstream of the system fan to prevent water condensation, and to ensure all parts in contact with the process stream are above the acid dewpoint.

Anguil's design incorporates a fresh air preheat system that utilizes heat from the combustion chamber to heat fresh air. The amount of heat taken from the combustion chamber is controlled by the recycle damper. The damper position is controlled by a signal from the PLC with a pneumatic actuator and positioner. **The RTO inlet preheat temperature is 300°F.**

- Recycle damper internally lined with hard refractory
    - Sized based on a maximum combustion chamber temperature of 1800°F
    - **330 Stainless Steel** shaft and blade
    - Step seat in the refractory
- The static mixer will be constructed out of **304 Stainless Steel**



RTO SYSTEM FAN

The system fan is sized for -1 in. W.C. at the RTO inlet. This is equivalent to 100' of ductwork, with two elbows and 2500 fpm maximum velocity from T-dampers to oxidizer inlet. Any additional ductwork, elbows or duct velocity may affect fan selection.

- Twin City Fan, New York Blower or equal
- VFD rated motor
- Flexible connection on inlet/outlet of fan

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SYSTEM CONTROLS

The system controls are located in a **heated and air conditioned NEMA 3R** control panel enclosure mounted on the RTO skid. In the event of a system shutdown, the touch screen will indicate the cause of the shutdown via a digital message in English.

- **NEMA 3R main control panel enclosure to be mounted on the oxidizer skid**
- Allen Bradley CompactLogix family PLC (Programmable Logic Controller) controls
- **Allen Bradley Panelview 1000** display
- Digital chart recorder: monitors combustion chamber and exhaust stack temperatures
- Ethernet modem for remote diagnostics and service support
- ***Optional pricing is given to upgrade Yamatake transmitters to Rosemount***

VARIABLE FREQUENCY DRIVE (VFD)

The variable frequency drive regulates the airflow through the system. It is controlled by a pressure transmitter located up-steam from the system fan. The VFD is mounted with the system controls in the control enclosure. It aids in minimizing operating cost by providing system fan turn-down during periods of low airflow.

- Allen Bradley Powerflex VFD
    - Mounted in an Anguil supplied **heated and air conditioned NEMA 3R panel enclosure**

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ENERGY RECOVERY CHAMBERS

The RTO's energy recovery chambers are rectangular cross-sections constructed of**vinyl ester coated carbon steel**. They are reinforced to withstand the pressure requirement of the process air fan and all other applied loads. A **316L Stainless steel** support structure is also provided to support the oxidizer chambers, media support grid and the ceramic heat recovery media itself. In order to allow for routine inspection of the heat recovery media, cold face and media support grid, two hinged access doors complete with gaskets are included.

- Two (2) carbon steel energy recovery chambers
  - Internally insulated: 6" thick, 8# density ceramic module insulation
  - Insulation rated for 2300°F
  - Insulation modules: shop installed with 310 stainless steel reinforcements and mounting hardware
  - **Internally coated with a vinyl ester coating to protect against sulfuric and carbonic acid corrosion**
- Support Structure – **316L Stainless Steel construction**
- Media support grid – **316L Stainless Steel construction**
- Two hinged access doors with gaskets

COMBUSTION CHAMBER

The combustion chamber is a rectangular cross-section constructed of **vinyl ester coated carbon steel** and reinforced to withstand the pressure requirements of the process air fan and all other applied loads. The inverted "U" shape design provides the retention time to obtain the specified VOC destruction efficiency. In order to allow for routine inspection of the heat recovery media, insulation and b burner, two hinged access doors complete with gaskets are included.

- Inverted "U" shaped oxidation chamber
  - Internally insulated: 8" thick, 8# density ceramic module insulation
  - Insulation rated for 2300°F
  - Insulation modules: shop installed with 310 stainless steel reinforcements and mounting hardware
  - **Internally coated with a vinyl ester coating to protect against sulfuric and carbonic acid corrosion**
- Hinged access doors with gaskets

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EXHAUST STACK

- Constructed of **316L stainless steel**
- Guy wired construction
- Two (2) EPA tests ports provided at 90°, to each other
- **An oxygen analyzer will be supplied in the RTO exhaust stack to control the dilution air and ensure 3% oxygen content in the RTO exhaust gas**
- ***Optional pricing is given for free standing construction with ladder and platform to sample ports***
- *External insulation of the lower exhaust stack section (10') for personnel protection and to prevent water condensation has not been included at this time. Anguil recommends that it will be the most cost effective to insulate onsite during installation.*

PAINTING

- All welds caulked prior to painting
- All exposed surfaces of the oxidizer will be primed and painted with two (2) shop coats of Anguil's standard high temperature coating
- UV resistant polyurethane paint
- Paint color can be specified by the customer
- Access platforms, support structures, and access ladders are primed and painted with one coat of Anguil's standard coating.
- Combustion air piping as well as natural gas and compressed air piping will be primed and painted with one coat of Anguil's standard coating. All other equipment will be the manufacturer's standard paint and color.

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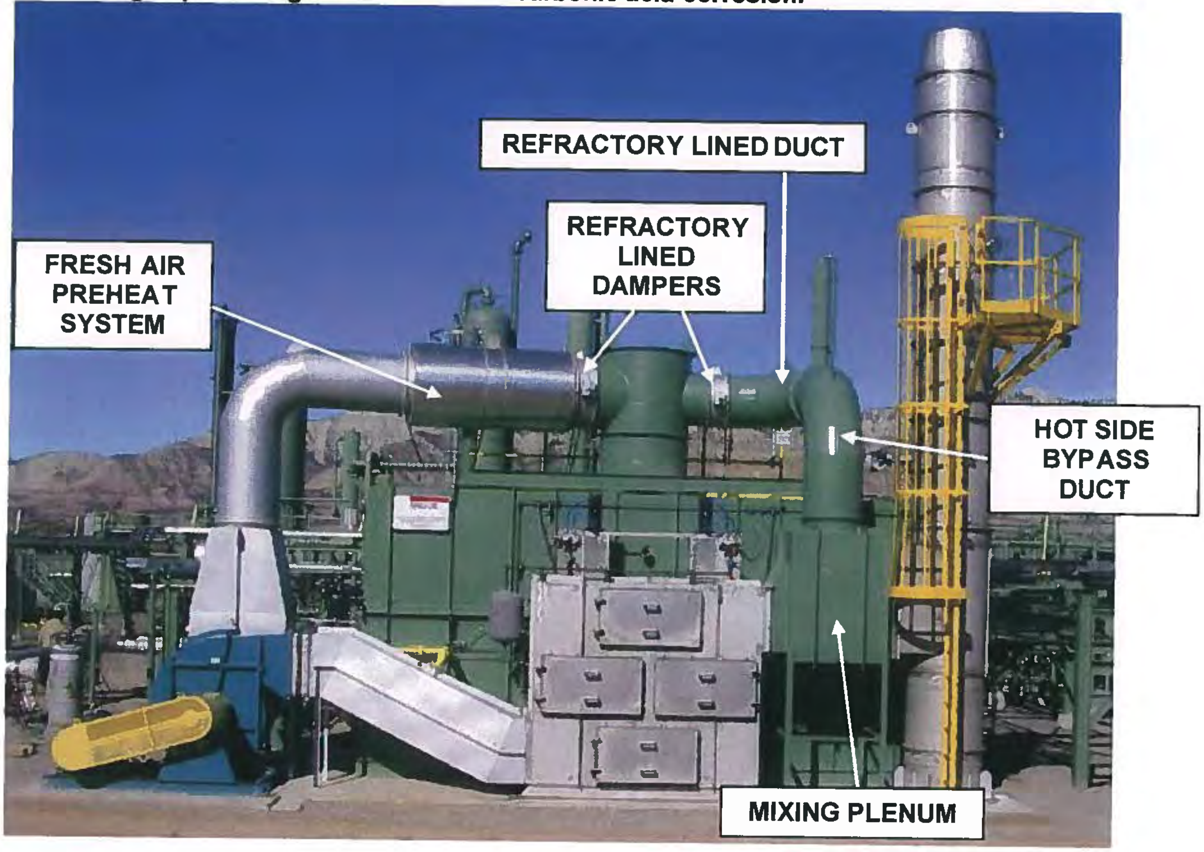
HOT SIDE BYPASS

- This bypass will be used during periods of high solvent loading
- Allows unit to handle high VOC loads
- Hot bypass damper internally lined with hard refractory
- 330 stainless steel shaft and blade
- Damper position controlled by PLC and driven with pneumatic actuator with positioner
- Internally lined bypass duct to mixing plenum
- Duct and valve sized based on maximum temperature of 1800°F
- Hot gas routed in refractory-lined duct to a mixing plenum on grade
- The refractory-lined duct will provide the necessary residence time to achieve the required DRE
- **Duct will be manufactured out of carbon steel and internally coated with with vinyl ester coating to protect against sulfuric and carbonic acid corrosion.**



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SUPPLEMENTAL FUEL INJECTION SYSTEM (SFI)

The Anguil Supplemental Fuel Injection (SFI) system is designed as a high efficiency means of controlling the RTO reaction chamber temperature. During system operation, when appropriate safeties have been satisfied, the burner and combustion air systems are turned off and the RTO combustion chamber temperature is maintained by injecting natural gas directly into the VOC laden airstream – typically at or near the inlet of the RTO system. The benefits of SFI are:

- **Provides high fuel efficiency by reducing combustion air**
- **Provides ultralow NOx emissions with flameless operation**
- **Provides a more uniform temperature profile throughout the RTO**

All natural gas injection systems enjoy these benefits, but not all systems are created equally. To date, Anguil's level of safety and controls for natural gas injection have been unmatched by our competitors.

A few of the highlights are:

- Some gas injection systems are designed as solenoid-type full-on or full-off systems. Anguil uses modulating injection valves for more precise control.
- Some gas injection systems are not designed for proper mixing of the natural gas with the solvent laden airstream. Anguil's SFI system is designed with multiple levels of safeties and a custom designed injection quill to ensure a well mixed airstream is delivered to the RTO chamber.

Natural gas injection is an excellent means of reducing system operating cost and providing a cleaner "burn" when properly designed and applied.

Supplemental Fuel Injection (SFI)
Custom Designed Injection Quill

Supplemental Fuel Injection (SFI)
Additional Fuel Train Piping

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BAKE OUT

The oxidizer can be operated off-line from the process in a bake-out mode to allow for the removal of organic build-up on the cold face of the heat exchange media. At a reduced airflow, the outlet temperature is allowed to reach an elevated temperature before the flow direction is switched. This hot air vaporizes organic particulate that may have collected on the cold face of the heat exchange media. The flow direction is then switched and the opposite cold face is cleaned. The area below the media support grid will be insulated to prevent the temperature of the outer skin from increasing during bake-out.

OPERATION & MAINTENANCE MANUALS

- Two (2) hard copy sets of the Operation and Maintenance Manuals (O&M) containing the sequence of operation and drawings
- CD-ROM of all Vendor Bulletins

FINAL ASSEMBLY AND SHOP TEST

We pre-assemble and pre-test modular components in our factory to provide significant savings of time and money during installation and start-up. Units are prewired and pre-piped at the factory for improved quality control and trouble-free start-up.

- Temporary assembly of system
- Inspection of the unit for manufacturing quality
- Check fuel and electrical connections
- Starting of burner and fuel train
- Warning labels are installed
- Test ports are installed
- Run electrical rigid conduit
- Fans and motors installed, cleared of debris and checked for quality
- Valves to be cycled and set
- Customer is invited to witness shop testing

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Items Not Included

- Concrete pad / platform
- Dumpster
- Interconnecting wiring between process equipment / tee dampers
- All natural gas piping to RTO fuel train
- High gas pressure regulator
- All compressed air piping to RTO air train (-40F dewpoint requirement) and tee dampers
- Winterization of the pneumatic piping and sensing lines
- Insulation and cladding for water condensation and personnel protection
- Power source to RTO control panel
- Ductwork/dampers from process to oxidizer inlet
- Insulation of ductwork, valves, fan and exhaust stack
- Oxidizer recycle fan and combustion air fan disconnects
- Personnel protection, security fencing and lighting
- Moving of oxidizer obstructions, fencing, landscaping, etc.
- Multiple installation trips if delays beyond Anguil's control
- All roof and building penetrations
- All fire suppression piping and controls
- All required sound abatement equipment
- Compliance testing
- Phone line to modem
- Taxes, permits
- Overtime, holiday or weekend work
- Mechanical and electrical installation (Can be quoted as an option)
- Startup and training (Quoted as a daily rate)
- Budget Freight (Can be quoted as an option)

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ATKINS

Appendix D

TCEQ "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives," October 2000

TNRCC

October 2000
Draft

Air Permit Technical Guidance for
Chemical Sources:

Equipment Leak Fugitives

Air Permits Division
Texas Natural Resource Conservation Commission

printed on recycled Paper

TNRCC

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Published and distributed by:
Texas Natural Resource Conservation Commission
P.O. Box 13087
Austin TX 78711-3087

TECHNICAL DISCLAIMER

THIS PACKAGE IS INTENDED FOR INSTRUCTIONAL USE ONLY

References to abatement technologies are not intended to represent minimum or maximum levels of BACT. Determinations of BACT are made on a case by case basis as part of the New Source Review of permit applications. BACT determinations are always subject to adjustment in consideration of specific process requirements, air quality concerns, and recent developments in abatement technology. Additionally, specific health effects concerns may indicate stricter abatement than required by the BACT determination.

The represented calculation methods are intended as an aid in the completion of an acceptable submittal; alternative calculation methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data.

The enclosed regulations are applicable as of the publication date of this package, but are subject to revision during the application preparation and review period. It is the responsibility of applicants to remain abreast of regulation developments which may affect their industries.

The special conditions included in this package are for purposes of example only. Special conditions included in an actual permit are written by the reviewing engineer to address specific permit requirements and operating conditions.

The electronic version of this document may or may not contain attachments or forms (such as the PI-1, Standard Exemptions, or Tables) that can be obtained electronically elsewhere on the TNRCC Internet site.

EQUIPMENT LEAK FUGITIVES

This document is intended to aid the permit applicant in the preparation of a technically complete permit application. The fugitive emissions discussed in this standardization package refer to the emissions from piping components and associated equipment including valves, connectors, pumps, compressor seals, relief valves, sampling connections, process drains, and open-ended lines. Uncaptured emissions emanating from other sources such as cooling towers, oil/water separators, material stockpiles, and loading operations are not addressed.

The TNRCC encourages pollution prevention, specifically source reduction, as a means of eliminating or reducing air emissions from industrial processes. The applicant should consider opportunities to prevent or reduce the generation of emissions at the source whenever possible through methods such as product substitutions, process changes, or training. Considering such opportunities prior to designing or applying “end-of-pipe” controls can not only reduce the generation of emissions, but may also provide potential reductions in subsequent control design requirements (e.g., size) and costs.

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I. REGULATIONS GOVERNING VOC EQUIPMENT LEAKS

A number of state and federal regulations exist that address volatile organic compounds (VOC) equipment leaks. All permit applications must demonstrate that a facility will be in compliance with all applicable Rules and Regulations. New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAPS and MACT) and TNRCC 30 TAC Chapter 115 have fugitive emission monitoring programs that vary depending on the specific industry, the material, and the county where the source is located. Each of the major fugitive emission monitoring programs required by state or federal regulation is listed below by industry type. For specific details, refer to the actual regulation in question.

PETROLEUM REFINERIES

30 TAC Chapter 115 (TNRCC Regulation V)

30 TAC § 115.352 Beaumont/Port Arthur, Dallas/Ft. Worth, Houston/Galveston and El Paso Areas

Leak definition of 10,000 ppmv for pump seals and compressors

Leak definition of 500 ppmv for all other components

30 TAC §115.322 Gregg, Nueces and Victoria Counties

Leak definition of 10,000 ppmv for all components

New Source Performance Standards (NSPS) (40 CFR Part 60)

40 CFR Part 60 Subpart GGG - Equipment Leaks of VOC in Petroleum Refineries (*Excluding those Subject to Subparts VV or KKK*)

National Emission Standards for Hazardous Air Pollutants (NESHAPS) (40 CFR Part 61)

Subpart J for benzene

Maximum Allowable Control Technology (MACT) (40 CFR 63)

Subpart CC - Petroleum Refineries

SYNTHETIC ORGANIC CHEMICALS MANUFACTURING INDUSTRY (SOCMI)

30 TAC Chapter 115 (TNRCC Regulation V)

30 TAC § 115.352	Beaumont/Port Arthur, Dallas/Ft. Worth, Houston/Galveston and El Paso Areas Leak definition of 10,000 ppmv for pump seals and compressors Leak definition of 500 ppmv for all other components
30 TAC § 115.322	Gregg, Nueces and Victoria Counties Leak definition of 10,000 ppmv for all components

New Source Performance Standards (NSPS)

40 CFR Part 60 Subpart VV — Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

National Emission Standards for Hazardous Air Pollutants (NESHAPS)

Subpart F for vinyl chloride, Subpart J for benzene

Hazardous Organic NESHAPS (HON)

Subpart H - Equipment Leaks

Subpart I - Certain Process Subject to the Negotiated Regulation for Equipment Leaks

NATURAL GAS PROCESSING

30 TAC Chapter 115 (TNRCC Regulation V)

30 TAC § 115.352	Beaumont/Port Arthur, Dallas/Ft. Worth, Houston/Galveston and El Paso Areas Leak definition of 10,000 ppmv for pump seals and compressors Leak definition of 500 ppmv for all other components

New Source Performance Standards (40 CFR Part 60)

Subpart KKK Equipment Leaks of VOC from Onshore Natural Gas Processing Plants (*Excluding those Covered Under Subparts VV or GGG*)

Maximum Allowable Control Technology (MACT) (40 CFR Part 63)

Subpart HH - Oil and Natural Gas Production Facilities

ADDITIONAL REQUIREMENTS

Please note that the regulations listed above are not an exhaustive list. New MACT standards are being proposed and promulgated that may contain LDAR requirements for specific industries. In addition, 30 TAC Chapter 115 may list fugitive emission inspection and monitoring requirements in sections other than those written specifically to address fugitive emissions. For example, fugitive inspection and maintenance requirements for marine terminals and gasoline terminals are contained in Section 115.214 of 30 TAC Chapter 115, Subchapter C, "Volatile Organic Compound Transfer Operations."

II. QUANTIFYING UNCONTROLLED EMISSIONS

Fugitive emission rates are estimates based on leak frequencies found in case studies of chemical plants, oil and gas facilities, refineries and gasoline marketing terminals. An average leak factor is used to determine what the fugitive emission rate is for an area, a facility, or an entire plant. In general, there are five different sets of fugitive emission factors: (1) refinery factors, (2) oil and gas production operations factors, (3) SOCMI factors, (4) petroleum marketing terminal factors, and (5) derived factors used for specific compounds. Within each of the five sets, different factors are used to estimate the uncontrolled emission rates for each specific type of component (connectors, valves, pumps, etc.) and for the type of material in service (light liquid, heavy liquid, or gas/vapor). Each of the leak factors accepted by the TNRCC for use in permit applications is discussed below. The emission factors are provided on Attachment II.

SOCMI FACTORS

The SOCMI factors are generally for use in chemical plants including chemical processes that are located in a refinery. SOCMI factors are divided into three different sets which are applied in different situations.

The original SOCMI average factors were developed to represent fugitive emission rates from all chemical plants. The SOCMI average factors are found in EPA 453/R-95-017, page 2-12. From these factors, the TNRCC further derived two additional sets of factors: "SOCMI with ethylene" to be used for components in service of material which is greater than 85% ethylene, and "SOCMI without ethylene" to be used where the ethylene concentration is less than 11%. For streams where the ethylene concentration is between 11% - 85%, the SOCMI average factors should be applied.

SOCMI NON-LEAKER FACTORS AND LOW VAPOR PRESSURE COMPOUNDS

Fugitive emissions from components in service where the material has a vapor pressure between 0.147 psia and 0.0147 psia should be estimated with the SOCMI Non-Leaker factors. The SOCMI Non-Leaker factors were developed from test data where no leaking emissions occurred above 10,000 ppmv; therefore, using the Non-Leaker factors assumes that no leaks will occur over the 10,000 ppmv leak detection threshold. For materials with a vapor pressure less than 0.0147 psia, fugitive emissions should be calculated using the SOCMI without ethylene factors with the Audio/Visual/Olfactory (AVO) reduction credits applied. In both cases, a weekly AVO inspection similar to the example condition given in Attachment I(E) will be required in the permit special conditions.

REFINERY FACTORS

Refinery factors are given in the Environmental Protection Agency's (EPA) Compilation of Air Pollutant Emission Factors, AP-42 (4th Edition), or EPA 453/R-95-017, page 2-13. Refinery factors are used when estimating fugitive emissions in a refinery process or production facility. A chemical process, such as a MTBE production unit, may be located in a refining facility but because it is not considered a refinery process, the refinery factors should not be used to calculate that specific unit's fugitive emissions.

PETROLEUM MARKETING TERMINAL FACTORS

In February of 1995 the Air Permits Division approved the use of the Petroleum Marketing Terminal Factors found in EPA document EPA-453/R-95-017, "Protocol for Equipment Leak Emission Estimates." These factors are used to estimate fugitive emissions from components at gasoline distribution facilities that are one-step removed from local gasoline stations and other end-users. Although gasoline distribution facilities may also handle jet fuel and diesel, gasoline is their primary product. Loading racks at chemical plants and refineries may not use these factors. Use of the petroleum terminal factors is accompanied by an AVO LDAR program performed on a monthly basis as specified in a permit special condition similar to the example condition in Attachment I(F). The petroleum marketing terminal factors include the appropriate reduction credit for the AVO inspection; therefore, no additional reductions to the factors are necessary. The decision to require an AVO program instead of an instrument inspection was based on the EPA/API bagging study of various gasoline distribution facilities employing a variety of LDAR programs. The results of the study indicated that little or no improvement in fugitive emission control was achieved when an instrument was used to detect leaks at this type of facility.

OIL AND GAS PRODUCTION OPERATIONS FACTORS

The Oil and Gas Production factors are based on EPA evaluated data on equipment leak emissions from the oil and gas production industry gathered by the American Petroleum Institute (API). There are four different equipment service categories covered by the Oil and Gas Production factors: Gas, Heavy Oil (< 20° API gravity), Light Oil (> 20° API gravity), and Water/Light Oil (water streams in light oil service with a water content between 50% and 99%). The gas factors estimate total hydrocarbon emissions; therefore, the calculated emission rates must be multiplied by the weight percentage of C3+ compounds in the gas stream to get a total VOC rate for permitting purposes. It is important to note that the Oil and Gas Production Operations gas factors replace the Gas Plant Fugitive Factors from the previous EPA protocol document (EPA-453/R-93-026).

Operators of crude oil pipeline facilities which handle weathered or "dead" crude may use the Oil and Gas Heavy Oil (< 20° API gravity) factors to estimate fugitive emissions. This decision was based upon technical demonstrations by the industry that weathered crude is free of the entrained gases and easily volatilized light ends which affected the fugitive emissions factors based upon studies at tank batteries and other upstream facilities.

PHOSGENE, BUTADIENE, AND ETHYLENE OXIDE FACTORS

Specific factors have been developed for use with components in phosgene, butadiene, and ethylene oxide service. These factors are used to estimate fugitive emissions from components in phosgene, butadiene, and ethylene oxide service when monitored with the 28MID Leak Detection and Repair Program at the following leak definitions:

Phosgene	50 ppmv
Butadiene	100 ppmv
Ethylene Oxide	500 ppmv

Note: the EO connector factor does not include instrument monitoring. An additional reduction credit can be taken if connector monitoring is required.

ODOROUS/INORGANIC COMPOUNDS

For odorous or toxic inorganic compounds such as chlorine (Cl_2), ammonia (NH_3), hydrogen sulfide (H_2S), hydrogen fluoride (HF), and hydrogen cyanide (HCN), fugitive emissions are calculated in the same manner as any VOC fugitive emissions according to the type of facility. Although the VOC emission factors were not developed specifically for use with inorganic compounds, they are presently the best tool available for estimating fugitive emissions of inorganics.

The calculated uncontrolled emission rates can be reduced according to the credit allowed by any monitoring program to be implemented at the facility. The emission rates of the inorganic compounds are determined through speciating (see Attachment IV) the calculated total emission rate by multiplying the total emission rate by the weight percent of each individual compound present in the stream. Note that there are no additional monitoring requirements for inorganic compounds if the maximum predicted off-property impact is acceptable. If it is expected that the leakage of these compounds would be detected by smell before an instrument monitoring device would register a leak, see Section III for information on reducing the emission rate of inorganic compounds through a physical inspection program.

LIGHT/HEAVY LIQUIDS

Several of the factors make a distinction between the leak rate for heavy liquids and light liquids. For purposes of choosing an emission factor, heavy liquids are defined as having a vapor pressure of 0.044 psia or less. Light liquids are the liquids with vapor pressures higher than 0.044 psia at 68°F.

COMPONENTS EXEMPT FROM MONITORING REQUIREMENTS

Emissions from components exempt from monitoring requirements based on size, physical location at a facility, or low vapor pressure *MUST* be calculated and included in the estimated fugitive emission rate regardless of any monitoring exemptions. There are presently no exemptions based on component size in Regulation V for the ozone nonattainment counties as mandated by EPA. In Gregg, Nueces, and Victoria Counties, valves with a nominal size of two inches or less are exempt from monitoring provided that certain requirements are met.

None of the 28 Series Leak Detection and Repair (LDAR) programs requires instrument monitoring of valves less than two inches in diameter; however, if the facility is located in an ozone nonattainment county and is subject to monitoring under 30 TAC 115.352, the two inch exemption will be removed from the permit conditions to be consistent with the regulation. In addition, certain non-accessible components, as defined in 30 TAC Chapter 115, are exempt from monitoring requirements. Monitoring requirements also vary depending on the vapor pressure of the compound. Fugitive emissions from components in heavy liquid service may be exempt from monitoring; however, the uncontrolled emissions must still be estimated.

SCREWED FITTINGS, LIQUID RELIEF VALVES, AND NON-EMITTING SOURCES

Factors have not been developed for certain types of piping components. In order to ensure consistency the TNRCC has designated the factor of a component with similar characteristics to be used to estimate fugitive emissions as follows:

I. Emissions from screwed fittings should be estimated in the same manner as flanges.

II. Emissions from liquid relief valves should be estimated in the same manner as light liquid valves.

III. Emissions from agitators should be estimated in the same manner as light liquid pumps.

Fugitive emissions should not be estimated from the following sources:

1) Tubing size lines (flexible lines ≤ 0.5'' in diameter) and equipment if they are not subject to monitoring by any federal or state regulation
2) Non-piping type fittings (swedgelock or ferrule fittings),
3) Streams where the operating pressure is at least 0.7 psi below ambient pressure,
4) Mixtures in streams where the VOC has an aggregate partial pressure of less than 0.002 psi at 68° Fahrenheit.

**Regardless of the guidance given above, if a piping component is required to be monitored by a state or federal regulation, the fugitive emissions from that component must be estimated.

PROCESS DRAINS

Facilities subject to fugitive emission monitoring under 30 TAC §§115.322 and 352 are required to monitor process drains on an annual basis. A 75 percent reduction credit may be applied for annual monitoring of process drains at a leak threshold of 500 ppmv provided the drain is designed in such a manner that repairs to leaking drains can be achieved. For example, flushing a water seal on a leaking process drain would constitute repair, so a 75 percent reduction credit may be applied.

At present, the Refinery Factors are the only set of accepted emission factors that include a factor for fugitive emissions from process drains. This factor may be applied to any process drain regardless of facility or industry type.

HOURS OF OPERATION

Fugitive emission factors are independent of process unit throughput and are assumed to occur if there is material in the line, regardless of the activity of the process. Because fugitive emissions occur when there is material in the line, the hours in service for all streams should always be 8,760 hours annually regardless of process downtime. Any exception to this service time would require a permit condition requiring the lines to be purged during process downtime.

CORRELATION EQUATIONS AND PLANT SPECIFIC FACTORS

The use of various correlation equations developed by EPA for estimating fugitive emissions is not accepted for permitting purposes. Since actual monitoring data is required by the equations, they can be used for estimating actual emissions for emission inventory purposes.

Emission factors developed for individual facilities are also not accepted for permitting purposes. Such factors are the results of individual bagging studies which the TNRCC Air Permits Division does not have the resources to quality assure.

III. FUGITIVE EMISSION REDUCTION OPTIONS

There are two methods by which fugitive emission rates can be reduced: leak detection and repair (LDAR) programs and equipment specification.

LEAK DETECTION AND REPAIR (LDAR) PROGRAMS

Leak detection and repair programs can be differentiated by four key criteria:

1) Leak definition
2) Monitoring frequency
3) Properties of the monitored compounds
4) Requirements for repair

The leak definition is the monitored concentration, defined in ppmv, which identifies a leaking component needing repair.

The second criterion, monitoring frequency, varies depending on the component types and the LDAR program in place. Components typically must be monitored on a quarterly basis; however, some programs allow facilities to skip monitoring periods when the percentage of leaking components is maintained under a specified rate.

The third criterion involves LDAR programs which define the components to be monitored by the vapor pressure of the material in the component and the weight percent of VOC in the stream.

The fourth and final criterion is whether the program repair requirements are directed or non-directed maintenance. A directed maintenance program requires that a gas analyzer be used in conjunction with the repair or maintenance of leaking components to assure that a minimum leak concentration is achieved. If a replacement is required to fix a leaking component, the replaced component should be re-monitored within 15 days. A non-directed maintenance does not require the use of a gas analyzer during repair or maintenance of a leaking component.

40 CFR Part 60, 40 CFR Part 61, MACT and Chapter 115 all have LDAR programs required for specific industries, counties, and materials. Refer to Section I to determine if a facility must meet the requirements of these monitoring and repair programs. Also, remember that a facility may be subject to more than one monitoring program and that meeting the requirements of one program does not exempt a facility from the requirements of another. For example, a chemical plant in Harris County may be subject to the monitoring requirements of Regulation V and also have a permit containing the 28MID LDAR program.

There are five instrument assisted leak detection and repair programs to choose from for permitting purposes: 28M, 28RCT, 28VHP, 28MID and 28LAER. LDAR programs allow emission control credits for instrument monitored components and for the physical (AVO) inspection of connectors. These credits can only be given in cases where the components are actually inspected and for components for which the LDAR program could result in emission reductions. A 30% reduction of fugitive connector emission rates is allowed when a weekly AVO inspection is performed. As mentioned previously, components smaller than two inches not subject to fugitive monitoring by regulation are exempt from monitoring requirements. Instrument monitoring of connectors and components less than two inches can be given a reduction credit consistent with the LDAR program if additional emission reductions are needed or desired. The 28LAER LDAR program is used.

strictly to control fugitive emissions which are part of a non-attainment permit. For facilities which are not subject to a non-attainment permit, the same emission reductions may be attained by implementing the 28MID program in conjunction with the 28CNTA LDAR program for connectors.

In an effort to keep the LDAR programs used as permit special conditions as concise as possible, the procedures to justify delay of repair for a leaking component are not outlined in the 28 series LDAR programs and default to the requirements of 30 TAC Chapter 115. The 28 series LDAR programs also use the 30 TAC Chapter 115 definition for nonaccessible valves.

Each of the five instrument monitoring programs is outlined in Table 1.

Table I
Leak Detection and Repair (LDAR) Program Options

LDAR Program		28M	28 RCT	28 VHP	28 MID	28 LAER
Leak Definition	Pumps and Compressors	10,000 ppmv	10,000 ppmv	2,000 ppmv	500 ppmv	500 ppmv
	All Other Components	10,000 ppmv	500 ppmv	500 ppmv	500 ppmv	500 ppmv [2]
Applicable Vapor Pressure		> 0.5 psia at 100°F	> 0.044 psia at 68°F	> 0.044 psia at 68°F	> 0.044 psia at 68°F	> 0.044 psia at 68°F
Monitoring Frequency		Quarterly	Quarterly	Quarterly	Quarterly	Quarterly [2]
Directed/Nondirected Maintenance		Nondirected	Nondirected	Nondirected	Directed	Directed
Equivalent State/Federal Programs		40CFR Part 60/40 CFR Part 61	30 TAC 115.352 [1]	MACT	N/A	Nonattainment NSR

1) Except in Gregg, Nueces, and Victoria Counties where 28 M applies.
2) Connectors are required to be monitored annually with an instrument under 28LAER.

LOW VAPOR PRESSURE COMPOUNDS

Compounds with low vapor pressures can present a problem with instrument monitoring. No reduction credits are allowed for valves and pumps in heavy liquid service under any of the five 28 Series LDAR programs or 30 TAC 115 as components in heavy liquid service are not required to be monitored. An applicant may propose to monitor these components and take the appropriate reduction credits as noted in Attachment III; however, the applicant must demonstrate that leaking components can be detected by implementing an instrument assisted fugitive monitoring program. For materials with vapor pressures below 0.147 psia, implementing a LDAR program with a 10,000 ppmv leak detection definition could be useless as leaking components may never be detected. For example, a component in heavy liquid service (vapor pressure < 0.044 psia) which is subject to a LDAR program with a leak definition of 10,000 ppmv would have a theoretical-saturation concentration of 0.044/14.7 = 2990 ppmv. Depending on the instrument response factor for the compounds being measured, this concentration may or may not be a measurable quantity; thus, it may not be possible to demonstrate an actual emission reduction via instrumental monitoring. These components would never get any increased maintenance or improved emission rates as a result of a LDAR Program with a 10,000 ppmv leak definition; therefore, these components cannot receive any reduction credit. To reduce these emissions, the applicant would have to commit to a 500 ppmv or 2,000 ppmv leak definition program.

AUDIO/VISUAL/OLFACTORY WALK-THROUGH INSPECTION

If the predicted off-property impact of an inorganic/odorous compound is unacceptable based on a predicted exceedance of an Effects Screening Level (ESL) or a maximum allowable ground level concentration specified in one of the regulations, the applicant will be required to commit to an Audio/Visual/Olfactory (AVO) walk-through inspection similar to the permit condition shown in Attachment I(E). Note that the repair time given in this condition may be extended on a case by case basis.

Inorganic/odorous compound fugitive emission rates controlled through the AVO inspection are determined as follows:

The total number of components in service of the compound in question should be multiplied by the appropriate "SOCMI without ethylene" emission factor. The AVO reduction credits found in Attachment III should then be applied to the uncontrolled inorganic/odorous compound emission rates.

Please note that the AVO inspection program may only be applied to inorganic compounds for which instrument monitoring is not available. In limited instances the AVO inspection program may be applied to extremely odorous organic compounds, such as mercaptans.

REDUCTION CREDIT FOR ANNUAL AND QUARTERLY CONNECTOR MONITORING

Annual instrument monitoring of connectors at a 500 ppmv leak detection limit may receive a 75 percent reduction credit. This determination is based on information contained in the 1993 EPA document "Protocol for Equipment Leak Fugitives" and the results from a limited amount of monitoring data. The control effectiveness percentages given in the protocol document are based on the type of facility, monitored data, and the corresponding reduction in the percentage of leaking flanges. A lower common denominator was used to establish the appropriate reduction credit as it is preferable to allow a single reduction credit for both chemical facilities and refineries. Thus, the 75 percent reduction credit is suitable for use at both petroleum refineries and SOCMI facilities

where the flanges are monitored annually at 500 ppmv. The 28CNTA LDAR program specifies the monitoring and recordkeeping necessary to receive the 75 percent reduction credit. This program may be used in conjunction with any of the other 28 series LDAR programs.

Quarterly instrument monitoring of connectors at a 500 ppm leak detection limit may receive a 97 percent reduction credit. This credit is equivalent to that received by valves monitored at the same leak detection limit and frequency. Although in theory an applicant could monitor connectors quarterly at a 10,000 ppm leak detection limit with a 75 percent credit, there would be a greater benefit for the cost in moving to a more stringent leak definition for the valves and other components prior to implementing connector monitoring. The 28CNTQ LDAR program specifies the monitoring and recordkeeping necessary to receive the 97 percent reduction credit. This program may be used in conjunction with any of the other 28 series LDAR programs.

EQUIPMENT SPECIFICATION

There are certain options that may be implemented in the design of a facility to prevent fugitive emissions from escaping into the atmosphere. When calculating emission rates, various control credits may be applied to components in service as described below. Also, LDAR program monitoring for identified types of equipment is not required if 100 percent reduction credit is given.

Relief Valves

100% control may be taken if one of the following conditions is met:

1) Route relief valve vents to an operating control device
2) Equip with a rupture disc and pressure sensing device (between the valve and disc) to monitor for disc integrity

Note that for new facilities, BACT guidelines generally require that all relief valves vent to a control device.

Pumps

Certain types of pumps are designed to be "leakless" and as such can be given 100% control. Any of the following designs are accepted as leakless pumps:

1) Canned Pumps
2) Magnetic Drive Pumps
3) Diaphragm Pumps
4) Double mechanical seals and the use of a barrier fluid at a higher pressure than the process
5) Double mechanical seals and venting the barrier fluid seal pot to a control device

Valves

100% control may be taken if one of the following conditions is met:

1) Use of bellows valves with bellows welded to both the bonnet and stem
2) Use of diaphragm-type valves
3) Use of seal-welded, magnetically actuated, packless, hermetically sealed control valves

Connectors

Connectors may receive 100% control credit if the connections are welded together around the circumference of the connection such that the flanges are no longer capable of being disassembled by simply unbolting the flanges.

Compressors

Compressors must be designed with enclosed distance pieces and must have the crankcase venting to a control device to be given 100% control.

Double Mechanical Seals

Any component employing double mechanical seals may be given a 75% credit. If the seals are monitored, then use the appropriate monitoring credit.

DESIGN OPTIONS

There are certain options that may be incorporated into the design of a facility to minimize piping components, improve maintenance and/or reduce susceptibility to leaks. While some of these options may not result in reduction credits for fugitive emissions, they can result in lower maintenance costs and improved performance in some cases.

Overall

1) Design equipment layout to minimize pipe run lengths and associated connectors.
2) Minimize the use of valves and other components.
3) Minimize whenever possible the use of relief valves.
4) Optimize piping and component metallurgy for compatibility with process streams and/or physical environment to reduce corrosion potential.

Pumps

1) Use of pressure transfer to eliminate the need for pumps.
2) Use of submerged pumps which limit the exposure of potential leaks to the atmosphere.

Valves

1) Optimize length of time between leaks by using special packing sets and stringent adherence to packing procedures.
2) Use of on-line direct injection repair equipment.
   Note: This option may introduce an additional potential leak path for the valve if corrosion occurs around the tap.

Connectors

1) Eliminate the use of screwed fittings smaller than 2 inches in diameter.
   Note: BACT for fugitives does not allow the use of screwed connections greater than 2 inches in diameter.
2) Use of new technologies which have been deemed by the TNRCC to be equivalent to flanges.

Compressors

1) Designs with lower leak potentials such as diaphragm compressors.
2) Shaft seal design such as carbon rings, double mechanical seals or buffered seals.
3) Design options such as internal balancing, double inlet or gland eductors.

QUANTIFYING FUGITIVE EMISSION REDUCTIONS

Here are several important points to remember when calculating fugitive emission rates:

1) All components must be accounted for when estimating emission rates regardless of exemptions from monitoring requirements.

2) Taking an emission reduction for monitoring implies that all of those components will be monitored regardless of exemptions.

3) Non-accessible components and other unmonitored components must be clearly identified and separated from monitored components when calculating emission rates.

4) All components given emission reduction credits for monitoring must be capable of having reduced emissions through the monitoring program, i.e., any components represented as being monitored must have sufficient vapor pressure to allow the reduction.

5) Representations of emission reductions in a permit application will result in permit special conditions requiring monitoring for certain components based on the emission estimates.

6) Instrument monitoring of connectors is not required by any of the LDAR programs other than 28 LAER. A 30% reduction can be taken for the required weekly walk-through inspection. For quarterly instrument monitoring of connectors under the 28CNTQ LDAR program, the valve credit corresponding to the appropriate leak definition for the LDAR program may be applied instead of the 30% credit. A 75% credit may be taken for annual connector monitoring at a 500 ppm leak definition in conjunction with the 28CNTA LDAR program. The 28CNT LDAR programs are used in addition to the other 28 series LDAR programs if connector monitoring is required by special circumstances.

7) Emission calculations should include a component count for those components with a 100% control efficiency with a footnote describing the specific method of control.

IV. INFORMATION NEEDED IN A PERMIT APPLICATION

COMPONENT COUNT, TYPE, AND SERVICE CATEGORY

The estimated fugitive emission rate is solely dependent on the number of components in service; therefore, a specific component count is necessary. The count should be separated into the component type categories, i.e., connector, valve, etc. For each specific component type, the number of components should be divided into the appropriate physical service category: gas, light liquid, heavy liquid, chlorine, etc.

With the separated source totals, an estimation of fugitive emission rates with no LDAR program in place can be made. This estimate is simply the emission factor, based on the specific compound and where it is in service, multiplied by the number of components in that service. As an example, for a valve in VOC light liquid service in a refinery, the factor used is 0.024 (lb/hr)/source; therefore, 10 of these valves will emit a total of 0.24 lb/hr. Annual emissions are determined from the short-term emission rate by assuming 8,760 hours per year of operation. The emission factors used in the calculations should be clearly footnoted to show the source of the factors.

CLAIMING EMISSION REDUCTIONS

Emission reductions claimed either though equipment specification or through any of the TNRCC leak detection and repair programs must be clearly identified. The fugitive emission calculations should show the emission factor, the appropriate reduction credit from Attachment III, and the final emission rate for each component type and, if applicable, from each different process stream. Refer to Attachment IV for a sample calculation.

SPECIATED EMISSIONS BY CHEMICAL

A speciation, or breakdown of the different compounds found in a process line, is necessary if the chemical composition is not 100% pure. The speciation is necessary to determine the off-property impact for each different chemical emitted from a fugitive source.

For example, if a line is 80% toluene and 20% ethylene, the emission rate would need to reflect the estimated quantity of emissions for each compound. Simply multiplying the emission rate by the weight percent of each compound yields the specific emission rate for that compound. If the weight percent of a particular compound varies from one process stream to another, then the fugitive emission rate for each area should be calculated separately, multiplied by the appropriate weight percent, and then totaled. The permit applicant may also group different streams together and determine the maximum percentage of each compound for that group. When using this method, the percentages may total over 100 percent. The total emission rate of each individual chemical should be shown on the Table 1(a), Emission Source Table, submitted with the permit application.

MODIFICATIONS

When submitting a permit application that involves changes to existing permitted equipment, show the existing component counts and emissions rate, the proposed component counts and emissions rate, and the overall changes. The new and increased emissions will be evaluated as part of the permit review process to determine if any off-property impact concerns exist.

V. BEST AVAILABLE CONTROL TECHNOLOGY GUIDELINES

An integral part of the permitting process is the determination of Best Available Control Technology (BACT) for all new and modified sources. Since fugitive emissions are estimated as a whole for a process unit or area, the addition of new piping components will trigger a BACT review for all of the piping components. Table II provides guidelines for determining BACT for process fug'tive emissions when submitting a permit application.

Table II

Best Available Control Technology Guidelines for Fugitive Emissions

Uncontrolled Annual Fugitive Emission Rate	**Best Available Control Technology (BACT)**
< 10 tpy	May Not Require Monitoring †
10 ≤ x < 25 tpy	28M Program †
≥ 25 tpy	28VHP Program

† If subject to TNRCC 30 TAC 115.352, 28RCT applies

It is important to note that the uncontrolled annual emission rate triggers and corresponding LDAR programs given in Table II are guidelines only; a case-by-case review will be performed for all permit applications. Separate applicability determinations must also be made for 30 TAC Chapter 115 (TNRCC Regulation V), 40 CFR Part 60, 40 CFR Part 61 or MACT affected sources. It is important to note that a more stringent program may be requested if it is currently in use at other units at the same plant site. For example, a new unit at a large chemical plant would be expected to implement at least the 28M leak detection and repair program even if the uncontrolled fugitive emissions from the new unit are calculated to be less than 10 tons annually.

In addition to the instrument monitoring requirements, certain components have additional requirements to meet BACT. Open-ended lines are required to be equipped with a cap, plug, blind flange or second valve as BACT. New relief valves are required to vent to a control device as BACT for any potential releases and as a side result any fugitive emissions are also controlled. If instrument monitoring is chosen for existing relief valves, monitoring must be performed quarterly regardless of the accessibility of the relief valves. Additional information on BACT for existing relief valves is contained in "Permit Review of Non-traditional Sources of Air Contaminants" by Alan Pegues, PhD., P.E., 1993.

OFF-PROPERTY IMPACTS REVIEW

The control technology determination is separate from the off-property impacts assessment performed during the permit review process. A more stringent LDAR program (up to 28MID) may be required if the TNRCC Toxicology and Risk Assessment Section determines that the predicted off-property impact of fugitive emissions is unacceptable. If impacts problems still exist with the 28MID LDAR program implemented, the following additional steps may be required:

1) Monitoring of connectors using an organic vapor analyzer as opposed to weekly physical inspections
2) Equipment specifications for leakless operation (See Section III)
3) Applicant developed proposal

SPECIAL CONDITIONS - 28M

Piping, Valves, Connectors, Pumps, and Compressors in Volatile Organic Compounds (VOC) Service - 28M

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.5 psia at 100°F or at maximum process operating temperature if less than 100°F or (2) to piping and valves two inches nominal size and smaller or (3) where the operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined in TNRCC 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring period after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations § 60.485(a) - (b) (40 CFR 60.485[a] - [b]).

G. Except as may be provided for in the special conditions of this permit, all pump and compressor seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. Seal systems that prevent emissions may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure or seals degassing to vent control systems kept in good working order.

Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves, connectors, compressor seals, and pump seals found to be emitting VOC in excess of 10,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Every reasonable effort shall be made to repair a leaking component as specified in this paragraph within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TNRCC Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

I. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TNRCC Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

J. Fugitive emission monitoring required by an applicable New Source Performance Standard (NSPS), 40 CFR Part 60, or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS), 40 CFR Part 61, may be used in lieu of Items F through I of this condition.

Compliance with the requirements of this condition does not assure compliance with requirements of NSPS or NESHAPS and does not constitute approval of alternate standards for these regulations.

SPECIAL CONDITIONS - 28RCT

Piping, Valves, Connectors, Pumps, and Compressors in Volatile Organic Compounds (VOC) Service - 28RCT

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure equal to or less than 0.044 psia at 68°F or (2) *** REMOVE IF SUBJECT TO REG. V* to piping and valves two inches nominal size and smaller** or (3) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by TNRCC 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations Part 60.485(a) - (b).

Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump and compressor seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump and compressor seals found to be emitting VOC in excess of 10,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired.

I. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TNRCC Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

J. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TNRCC Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

K. Fugitive emission monitoring required by 30 TAC Chapter 115 may be used in lieu of Items F through I of this condition.

Compliance with the requirements of this condition does not assure compliance with requirements of an applicable New Source Performance Standard or an applicable National Emission Standard for Hazardous Air Pollutants and does not constitute approval of alternative standards for these regulations.

SPECIAL CONDITIONS - 28VHP

Piping, Valves, Connectors, Pumps, and Compressors in Volatile Organic Compounds (VOC) Service - 28VHP

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 psia at 68°F or (2) *** REMOVE IF SUBJECT TO REG. V* to piping and valves two inches nominal size and smaller** or (3) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by TNRCC 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations Part 60.485(a) - (b).

Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump and compressor seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump and compressor seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired.

I. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TNRCC Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

J. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TNRCC Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

K. Alternative monitoring frequency schedules of 30 TAC Sections 115.352-115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR 63, Subpart H, may be used in lieu of Items F through G of this condition.

Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard, or an applicable National Emission Standard for Hazardous Air Pollutants and does not constitute approval of alternative standards for these regulations.

Piping, Valves, Connectors, Pumps, and Compressors in (insert compound) Service - Intensive Directed Maintenance - 28MID

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. These conditions shall not apply (1) where the concentration in the stream is less than XX percent by weight or (2) where the volatile organic compounds (VOC) has an aggregate partial pressure or vapor pressure of less than 0.044 psia at 68°F or (3) *** REMOVE IF SUBJECT TO REG. V.* to piping and valves two inches nominal size and smaller** or (4) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by TNRCC 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer with a directed maintenance program. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations § 60.485(a) - (b).

A directed maintenance program shall consist of the repair and maintenance of components assisted simultaneously by the use of an approved gas analyzer such that a minimum concentration of leaking VOC is obtained for each component being maintained. Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. All new and replacement pumps and compressors shall be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. These seal systems need not be monitored and may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

All other pump and compressor seals emitting VOC shall be monitored with an approved gas analyzer at least quarterly.

H. Damaged or leaking valves, connectors, compressor seals, and pump seals found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TNRCC Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

I. In lieu of the monitoring frequency specified in paragraph F, valves in gas and light liquid service may be monitored on a semiannual basis if the percent of valves leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Valves in gas and light liquid service may be monitored on an annual basis if the percent of valves leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of valves leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

J. The percent of valves leaking used in paragraph I shall be determined using the following formula:

$$(Vl + Vs) \times 100/Vt = Vp$$

Where:

Vl = the number of valves found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

Vs = the number of valves for which repair has been delayed and are listed on the facility shutdown log.

Vt = the total number of valves in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor valves.

Vp = the percentage of leaking valves for the monitoring period.

K. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TNRCC Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard, or an applicable National Emission Standard for Hazardous Air Pollutants and does not constitute approval of alternative standards for these regulations.

SPECIAL CONDITIONS - 28LAER

Piping, Valves, Connectors, Pumps, Agitators, and Compressors in Volatile Organic Compounds (VOC) Service - Intensive Directed Maintenance - 28LAER

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. With the exception of paragraph N, these conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 psia at 68°F or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by TNRCC 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through. In addition, all connectors shall be monitored by leak-checking for fugitive emissions at least annually using an approved gas analyzer with a directed maintenance program.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer with a directed maintenance program. Non-accessible valves shall be monitored by leak-checking for fugitive emissions at least annually using an approved gas analyzer with a directed maintenance program. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations § 60.485(a) - (b).

A directed maintenance program shall consist of the repair and maintenance of components assisted simultaneously by the use of an approved gas analyzer such that a minimum concentration of leaking VOC is obtained for each component being maintained. Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. All new and replacement pumps and compressors shall be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. These seal systems need not be monitored and may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

All other pump, compressor, and agitator seals emitting VOC shall be monitored with an approved gas analyzer at least quarterly.

H. Damaged or leaking valves, connectors, agitator seals, compressor seals, and pump seals found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. At the discretion of the TNRCC Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

I. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TNRCC Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

J. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard, or an applicable National Emission Standard for Hazardous Air Pollutants and does not constitute approval of alternative standards for these regulations.

K. In lieu of the monitoring frequency specified in paragraph F, valves in gas and light liquid service may be monitored on a semiannual basis if the percent of valves leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Valves in gas and light liquid service may be monitored on an annual basis if the percent of valves leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of valves leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

L. The percent of valves leaking used in paragraph K shall be determined using the following formula:

$$(Vl + Vs) \times 100/Vt = Vp$$

Where:

Vl = the number of valves found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

Vs = the number of valves for which repair has been delayed and are listed on the facility shutdown log.

Vt = the total number of valves in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor valves.

Vp = the percentage of leaking valves for the monitoring period.

M. Alternative connector monitoring frequency schedules ("skip options") of 40 Code of Federal Regulations Part 63, Subpart H, National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks, may be used in lieu of the annual connector instrument monitoring required by paragraph E of this permit condition.

N. Any component found to be leaking by physical inspection (i.e., sight, sound, or smell) shall be repaired or monitored with an approved gas analyzer within 15 days to determine whether the component is leaking in excess of 500 ppmv of VOC. If the component is found to be leaking in excess of 500 ppmv of VOC, it shall be subject to the repair and replacement requirements contained in this special condition.

AUDIO, VISUAL AND OLFACTORY (AVO) INSPECTION

Piping, Valves, Pumps, and Compressors in (insert compound) Service

A. Audio, olfactory, and visual checks for (insert compound) leaks within the operating area shall be made every four hours.

B. Immediately, but no later than one hour upon detection of a leak, plant personnel shall take the following actions:

(1) Isolate the leak.

(2) Commence repair or replacement of the leaking component.

(3) Use a leak collection/containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.

Date and time of each inspection shall be noted in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the Texas Natural Resource Conservation Commission (TNRCC) upon request.

PETROLEUM MARKETING TERMINAL AUDIO, VISUAL, AND OLFACTORY (AVO) INSPECTION

Piping, Valves, Pumps, and Compressors in Petroleum Service

A. Audio, olfactory, and visual checks for petroleum product leaks within the operating area shall be made monthly.

B. Every reasonable effort shall be made to repair or replace a leaking component within 15 days after a leak is found. If the repair or replacement of a leaking component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired or replaced until a scheduled shutdown shall be identified in a list to be made available to representatives of the Texas Natural Resource Conservation Commission (TNRCC) upon request.

Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the TNRCC upon request.

28 CNTA

In addition to the weekly physical inspection required by Item E of Special Condition XX, all connectors in gas\vapor and light liquid service shall be monitored annually with an approved gas analyzer in accordance with Items F thru J of Special Condition XX. Alternative monitoring frequency schedules ("skip options") of 40 Code of Federal Regulations Part 63, Subpart H, National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks, may be used in lieu of the monitoring frequency required by this permit condition. Compliance with this condition does not assure compliance with requirements of applicable state or federal regulation and does not constitute approval of alternative standards for these regulations.

28CNTQ

A. In addition to the weekly physical inspection required by Item E of Special Condition XX, all accessible connectors in gas\vapor and light liquid service shall be monitored quarterly with an approved gas analyzer in accordance with Items F thru J of Special Condition XX.

B. In lieu of the monitoring frequency specified in paragraph A, connectors may be monitored on a semiannual basis if the percent of connectors leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Connectors may be monitored on an annual basis if the percent of connectors leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of connectors leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

Uncontrolled SOCMI Fugitive Emission Factors

Equipment/Service	SOCMI Average [1]	SOCMI Without C_2 [2]	SOCMI With C_2 [2]	SOCMI Non-Leaker[3]
Valves				
Gas/Vapor	0.0132	0.0089	0.0258	0.00029
Light Liquid	0.0089	0.0035	0.0459	0.00036
Heavy Liquid	0.0005	0.0007	0.0005	0.0005
Pumps				
Light Liquid	0.0439	0.0386	0.144	0.0041
Heavy Liquid	0.019	0.0161	0.0046	0.0046
Flanges/Connectors				
Gas/Vapor	0.0039	0.0029	0.0053	0.00018
Light Liquid	0.0005	0.0005	0.0052	0.00018
Heavy Liquid	0.00007	0.00007	0.00007	0.00018
Compressors	0.5027	0.5027	0.5027	0.1971
Relief Valve (Gas/Vapor)	0.2293	0.2293	0.2293	0.0986
Open-ended Lines [4]	0.0038	0.004	0.0075	0.0033
Sampling Connections [5]	0.033	0.033	0.033	0.033

Notes: All factors are in units of (lb/hr)/component.
1. Factors are taken from EPA Document, EPA-453/R-95-017, November 1995, Page 2-12.
2. Factors are TNRCC derived.
3. Control credit is included in the factor; no additional control credit can be applied to these factors. AVO walk-through inspection required.
4. The 28 Series quarterly LDAR programs require open-ended lines to equipped with a cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.
5. Use the SOCMI Sampling Connection factor for Non-Leaker. Emission factor is in terms of Pounds per Hour per Sample Taken.

Facility/Compound Specific Fugitive Emission Factors

Equipment/ Service	Ethylene Oxide [1]	Phosgene [2]	Butadiene [3]	Petroleum Marketing Terminal [4]	Oil and Gas Production Operations [5]				Refinery [6]
					Gas	Heavy Oil <20° API	Light Oil >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
Valves						
Gas/Vapor	75%	97%	97%	97%	97%	97%
Light Liquid	75%	97%	97%	97%	97%	97%
Heavy Liquid [2]	0% [3]	0% [4]	0% [4]	0% [4]	0% [4]	97%
Pumps						
Light Liquid	75%	75%	85%	93%	93%	93%
Heavy Liquid [2]	0% [3]	0% [3]	0% [5]	0% [6]	0% [6]	93%
Flanges/Connectors						
Gas/Vapor [7]	30%	30%	30%	30%	75%	97%
Light Liquid [7]	30%	30%	30%	30%	75%	97%
Heavy Liquid	30%	30%	30%	30%	30%	97%
Compressors	75%	75%	85%	95%	95%	95%
Relief Valve (Gas/Vapor)	75%	97%	97%	97%	97%	97%
Open-ended Lines [8]	75%	97%	97%	97%	97%	97%
Sampling Connections	75%	97%	97%	97%	97%	97%

Notes:

1. Audio, visual, and olfactory walk-through inspections are applicable for inorganic/odorous and low vapor pressure compounds referenced in Section II.

2. Monitoring components in heavy liquid service is not required by any of the 28 Series LDAR programs. If monitored with an instrument, the applicant must demonstrate that the VOC being monitored has sufficient vapor pressure to allow the reduction.

3. No credit may be taken if the concentration at saturation is below the leak definition of the monitoring program (i.e. (0.044 psia/14.7 psia) x 10^6 = 2,993 ppmv versus leak definition = 10,000 ppmv)

4. Valves in heavy liquid service may be given a 97% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.

5. Pumps in heavy liquid service may be given an 85% reduction credit if monitored at 2,000 ppmv by permit condition provided that the concentration at saturation is greater than 2,000 ppmv.

6. Pumps in heavy liquid service may be given a 93% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.

7. If an applicant decides to monitor their connectors using an organic vapor analyzer (OVA) at the same leak definition as valves, then the applicable valve credit may be used instead of the 30%. If this option is chosen, the company shall continue to perform the weekly physical inspections in addition to the quarterly OVA monitoring.

8. The 28 Series quarterly LDAR programs require open-ended lines to equipped with a cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.

Sample Fugitive Emission Rate Calculations
Chemical Plant Implementing the 28VHP LDAR Program

Component Name	Stream Type	Number of Components	SOCMI w/o C_2 Emission Factors	LDAR Program	Control Efficiency	Controlled Emission Rates	
						Lbs/Hour	Tons/Year
Valves	Gas/Vapor	1,019	0.0089	28VHP	97%	0.27	1.19
Valves	Light Liquid	2,263	0.0035	28VHP	97%	0.24	1.04
Pumps	Light Liquid	14	0.0386	28VHP	85%	0.08	0.36
Connectors	Gas/Vapor	1,435	0.0029	28VHP	97% *	0.12	0.55
Connectors	Light Liquid	3,056	0.0005	28VHP	97% *	0.05	0.20
Compressors	Gas/Vapor	1	0.5027	28VHP	85%	0.08	0.33
Relief Valves	Gas/Vapor	12	0.2293	28VHP	100% †	0.00	0.00
Open-Ended Lines	Gas/Vapor	3	0.0040	28VHP	100% ††	0.00	0.00
Total Fugitive Emission Rates						**0.84**	**3.67**

* Flanges monitored at 500 ppmv; therefore, the valve control credit is applied.
† Relief valves routed to a flare; therefore, 100% control credit is applied.
†† The 28 Series LDAR Programs require open-ended lines to equipped with a cap, blind flange, plug, or a second valve for 100% control credit. The connector count is increased by the number of open-ended lines to account for the credit.

Fugitive Emission Speciation for Sample Calculations

Chemical Name	Weight Percent in Stream	Controlled Fugitive Emissions	
		Lbs/Hour	Tons/Year
Propane	4%	0.03	0.15
Benzene	7%	0.06	0.26
Toluene	62%	0.52	2.28
Xylene	8%	0.07	0.29
Ethylbenzene	17%	0.14	0.62
Hydrogen Sulfide *	2%	0.02	0.07
Total VOC	**98%**	**0.82**	**3.60**
Hydrogen Sulfide *	**2%**	**0.02**	**0.07**

* Calculation method assumes that the maximum off-property impact will not exceed ESL or Regulation II limits for H_2S. See Section II, Odorous/Inorganic Compounds, and Section III, Audio/Visual/Olfactory Walk-Through Inspection, for additional information.

ATKINS

Appendix E

Callidus Technologies - Proposal to Freeport LNG Dated October 2, 2011

Proposed Liquefaction Ground Flare

Honeywell

CALLIDUS TECHNOLOGIES

by Honeywell

Automation & Control Solutions
Honeywell
7130 South Lewis Avenue
Suite 335
Tulsa, OK 74136

Main Line: 918-496-7599

October 2, 2011

RE: RTIP Multipoint Ground Flare, LP Flare
Callidus File Number F-1109-140071, Rev. 0

Ladies and Gentlemen:

Callidus sincerely appreciates the opportunity to present the following proposal. We appreciate the time and effort you will invest to review and evaluate our offering. When appropriate, Callidus prefers to visit your office in order to more completely present the technical advantages and unique features of our technology. Our presentation will also include a review of Callidus' approach to your particular application, further outline of personnel background and experience and answers to any questions you may have.

It should be noted that our proposed design is almost exactly the same as an existing Callidus 1,800 ton/hour ethylene multipoint ground flare. It is currently operating in Saudi Arabia.

Not only are the unique qualifications of the Callidus team well-matched to your project, but the entire Callidus staff is totally committed to providing technically competent and timely completion of any work committed to us.

Should questions arise for which immediate answers are required, please do not hesitate to contact our local sales representative, Jack Hornsby, at (281)-236-5029.

Sincerely,

BlBeck

Bryan L. Beck
Applications Engineer
+01-918-523-2255
bbeck@callidus.com

cc: File

CB&I Ground Flare Freeport
Callidus File Number F-1109-140071, Rev. 0
October 2, 2011

A. PROCESS SPECIFICATIONS

FREEPORT LNG	Project Number	1008	Item Number		11Z-5
	Page	3 of 12	1008-011-PDS-0180-001		
	Revision	Date	Description		By
API-537 Flare Data Sheet US Customary Units	D	9/13/2011	FOR AIR PERMIT / FERC		SWC
	E	9/22/2011	ADD C2= CASES		SWC

	PROCESS DESIGN CONDITIONS - PURCHASER	Note	CASE 1	CASE 2	CASE 3	CASE 4	
1	Design Flare Capacity, lb/hr		945,000	765,000	675,000	450,000	
2	Smokeless Capacity		0-100%	0-100%	0-100%	0-100%	
3	Gas Temperature, deg F		-35.6	59.0	70.0	86.1	
4	Static Pressure at Flare Inlet, psig	8	15 MAX	15 MAX	15 MAX	15 MAX	
5	Flare Inlet Diameter, inches						
6	Veq. SCFH air equivalent						
7	Heat Release, MMBTU/hr						
8	Duration @ Max. Rate, min.						
9	Relief Source		SCENARIO 2	SCENARIO 1	SCENARIO 3	SCENARIO 3A	
10	Controlling Case-For . . .		NON-FIRE	FIRE	NON-FIRE	NON-FIRE	
11	GAS COMPOSITION (Mole% / Mass%)		mole%	mole%	mole%	mole%	
12	Methane		88.59	44.39	56.81	33.70	
13	Ethane		6.66	3.34	3.41	1.05	
14	Propane		2.82	51.31	9.95	15.13	
15	Isobutane		0.53	0.27	0.40	0.31	
16	n-Butane		0.32	0.16	0.13		
17	Isopentane		0.06	0.03	0.04	0.03	
18	n-Pentane		0.02	0.01	0.01		
19	Hexane		0.01				
20	Heptane						
21	Octane						
22	Ethylene				20.45	35.30	
23	Propylene						
24	Butylene						
25	Acetylene						
26	Butadiene						
27	Benzene						
28	Toluene						
29	Xylene						
30	Hydrogen						
31	Carbon Monoxide						
32	Hydrogen Sulfide						
33	Ammonia						
34	Water Vapor						
35	Nitrogen		0.99	0.49	8.80	14.48	
37	Carbon Dioxide						
38	Nonane						
39							
40	TOTAL (should be 100%)		100.00	100.00	100.00	100.00	
41	Molecular Weight		18.3	31.2	23.1	28.6	
42	Higher Heating Value, BTU/SCF						
43	Ratio of Specific Heats, Cp/Cv						
44	Viscosity, cp						
45	UEL, % in air						
46	LEL, % in air						

[redacted]

B. ENGINEERING ASSESSMENT

Ground Flare Engineering Assessment

The key to successful smokeless burning of waste material using a multipoint is to properly design the burner system and integrate that system into a properly designed staging control system. Of particular importance in a multipoint flare is obtaining a high enough kinetic energy level in the combustion zone to promote mixing between the waste gas and the surrounding air. This energy level can be generated through use of the waste gas pressure, steam injection, or through the addition of low pressure air. For this ground flare design, we will be pressurized burners to generate the required kinetic energy.

Ground Flare Burner Design

Of particular importance is the design of the burner and its ability to provide mixing over the widest possible range of flow rates. The burner must be designed to inspirate air flow in proportion to waste gas flow. In addition, the burner design must provide for stability of the waste gas under greatly varying flow conditions. This design is most easily achieved by using a spider-type burner whose center hub acts as a stability point for the burner, ensuring stable combustion through a wide range of compositions and turndowns. The Callidus burner has a web underneath each arm, which is different than the typical high pressure tip. The burner web adds reinforcement to the arms so that they can withstand the thermal stress where each arm meets the center hub. On typical high pressure burners, this stress causes a crack at each arm, which leads to failure of the burner. The web is hollow on the inside to provide a better flow pattern to the outermost holes on the spider. This ensures that the gas will reach the area of the burner with the greatest access to air.

A tall fence is not the only requirement for reduced visible flame in a multipoint flare system. Proper burner drilling is vital to ensure that flame length can be properly maintained. Even small changes in drilling can result in excessive burner flows with insufficient combustion air, causing smoke or increased flame lengths. Additionally, the burner layout must be carefully planned to ensure that sufficient combustion air reaches every burner. A lack of combustion air will always result in longer flame lengths and the potential for smoke.

Callidus knows better than anyone that the flame length produced by a single burner or small group is burners is much less than the flame length produced by a large operating multipoint. There's no way to adequately test the large-scale behavior of a multipoint flare system in a test facility. Only an operating facility can truly determine the flame behavior of a large multipoint flare system. The Callidus burner drilling and burner layout has been well proven to produce reduced visible flame in numerous facilities throughout the world.

Ground Flare Staging Control

The burner turndown must be controlled through use of a burner staging system, which matches the number of burners in service to the flow rate of waste gas which must be flared. Improper staging can result in smoking burners or excessive valve cycling.

In addition to the normal staging system controlled through the customer DCS, a completely separate override system is included in the controls package furnished by Callidus.

The override system consists of a separate pressure monitor on the flare inlet and a separate staging valve power relay in the staging control panel. The override is set at a pressure above the normal staging pressure but below the relief bypass pressure.

If the override system pressure is reached, the pressure monitor deenergizes the valve power relay, which removes electrical power from all of the staging valves. The staging valves then fail open.

The valves used in the staging system are open/close butterfly valves, designed for tight shut-off. They are backed up by a manual butterfly and spectacle blind next to the manifold to provide maintenance shut-off.

Ground Flare Pilot System

The pilot design for the Callidus flares are the result of intensive testing to improve pilot operation in several aspects.

- Wind stability. All Callidus pilots are equipped with windshields over the mixers. Additionally, we use a matched investment cast mixer and tip combination, designed for wind stability and longevity.
- Longevity. The pilot gas tip and flame shield are all investment castings of CK-20 material. CK-20 is a casting version of 310SS. The castings metallurgy, the lack of forming stresses, and the metal thickness combine to make a long lived pilot.

The pilots for the elevated flare system are very similar.

Ground Flare Post Purge System

Heavier than air gas "bleed-off" can cause the gas mixture in the burner runner to pass through the waste gas explosive limit range as it transitions to air in the runner pipe.

This problem is controlled by a post purge cycle of nitrogen or some other non-combustible gas. When the staging valve closes, the purge system opens up for a short period of time using enough pressure to achieve distribution in the runner. After the cycle is complete, as measured by a timer function in the programmable controller, the purge shuts-down. It is only in service for a short period (typically

120-180 seconds on large stages, shorter on small stages) after each stage closure.

Ground Flare Radiation Control

The radiation fence is designed to serve two functions. The first is to enclose the flame to limit the amount of flame that is visible from the area outside the fence. The second is to minimize radiation to an acceptable level outside the fence, especially at the staging manifold where operator access is required.

The fence is designed to be opaque and to meet structural standards of the local wind and seismic loadings. It is a hot dip galvanized structure with heavy spray-galvanized panels for bolted field erection.

The toughest technical challenge associated with a multipoint fence is that is must block radiation while still allowing sufficient combustion air to reach the burners. Without sufficient combustion air, burner flame lengths will increase and burners will have a greater tendency to smoke. Callidus' fence design is proven to produce reduced visible flame and smokeless flaring in numerous locations throughout the world.

Ground Flare Staging Manifold

The staging manifold provides a distribution header for the various stage valve setups. It is also a stable point for instrument connections for the staging controls.

Ground Flare Relief Bypass System

Because of the remote possibility of the staging valves failing to open in an emergency, an alternate flow path is always offered to provide unquestioned protection. This flow path is a relief bypass around the staging valve. We offer collapsing-pin style valves which will automatically open in case of an emergency. Unlike a burst disk or a rupture disk, this type of valve can be quickly reset without taking any part of the system offline.

Ground Flare Automatic High Energy Ignition System

The primary ignition system for this project is an automatic high energy ignition system. This system uses electric spark pilot ignition technology that is similar to that used to ignite jet engines. Pilot status is continuously monitored with thermocouples. Should the system detect a pilot outage, the high energy ignition system will automatically commence sparking to reignite the pilot. If the pilot does not reignite after a set period of time, the system will begin to alarm. The time until alarm is field adjustable.

Ground Flare Manual Flame Front Generator

The backup flare ignition system proposed is a manual flame front generator (FFG) system. A FFG is extremely reliable with limited moving parts that require maintenance. Additionally, should maintenance be required, all moving parts are accessible at grade and can be repaired without shutting down the flare system.

The system consists of a panel to which natural gas and air are piped. The panel includes a strainer, firing valve, restriction orifice and pressure gauge for both the air and the gas lines. An individual ignition line is required for each pilot. The flow of air/gas mixture is allowed to fill the ignition inch line to one of the pilots. In essence, this air/gas mixture forms a fuse between the flame front generator panel and the pilot. The ignition pushbutton is depressed to ignite the end of this air/gas mixture. A flame front travels through the ignition line between the panel and the pilot and ignites the pilot.

Flare Gas Liquid Content

No discussion of smokeless flaring can be complete without stating that the presence of liquid hydrocarbon in the combustion zone will limit smokeless flaring. Even small droplets (600 Microns or less) in large quantities will negatively impact the smokeless capacity of the flare. Any hydrocarbon gas, which will condense at ambient temperatures, must be considered a possible source of liquid hydrocarbon in the combustion zone. The best possible KO drum design must be used and the drum must be located as close to the flare as is possible.

C. SCOPE OF EQUIPMENT SUPPLY

C.1 Multipoint Ground Flare

This proposal consists of the multipoint flare tips, risers, runners, valves, pilots, purge system, high energy spark ignition system, manual flame front generator ignition system, pilot fuel piping, and control system.

C.1.1 Burner System

One (1) CTI model CAL-MP staged, multipoint flare system consisting of the following major components

- CF8 stainless steel investment cast burners.
- 7' minimum length 304 ERW stainless steel 3" diameter burner risers. This height may vary based on runner piping diameter.
- Two (2) pilots minimum per stage are included.
- Two (2) thermocouples with 310 stainless steel sheaths included per pilot. Thermocouples are retractable thermocouples.
- 304 stainless steel burner runners to provide for connection of the burner/riser assemblies. Burner runners are welded pipe.
- Stainless steel weld-o-lets for high-strength burner riser connections to the runners.
- One (1) lot of 304 stainless steel pilot gas piping.
- One (1) lot of 304 stainless steel FFG ignition piping.
- One (1) high energy electric spark type pilot ignition system.
- One (1) manual flame front generator backup pilot ignition system.

C.1.2 Staging Manifold

The following items are included:

- 304 stainless steel staging manifold constructed of rolled and welded plate.
- Stainless steel staging valves with quick open air actuators, open and closed limit switches, and tight shut-off seals. Valves are fire-safe, lug body, double offset valves.
- Stainless steel butterfly type block valves with manual actuators. Valves are fire-safe, lug body, double offset valves.
- Pin actuated bypass valves. Valves have a replaceable pin that is destroyed during a high-pressure event. Once the event is over, the pin can be quickly replaced.
- Carbon steel saddle-type supports as required to mount runners on customer supplied piers.
- Spectacle-type isolation blinds.
- Stainless steel manifold drain catch facility located near the manifold low point.

C.1.3 Flare Monitoring and Control Panel

The control panel includes:

- Connection point to the end-users DCS
- Staging valve auto-open control
- Staging valve open and closed indication
- Blown buckling pin indication
- Pilot ignition auto-off-manual control
- Pilot failure alarms based on each thermocouple input
- Z Type Purge System

C.1.4 Wind Fence

The flare field is surrounded by an opaque wind fence designed to contain the flame. It has the following features:

- Galvanized A36 (or equivalent) carbon steel construction for panels.
- Fence is designed for a wind load per the inquiry specifications.
- View ports to monitor the burner.
- Fence is 45 feet tall.
- Fence supports are hot dip galvanized.

C.1.5 Radiation Shielding

The runners in the flare field will be protected by gravel in the field (by others).

C.1.6 Platforms with Access Ladders

Platforms to be provided for access to the bypass valves and staging valves as required. The platforms and access ladders will be hot-dip galvanized. Ladders will provide access to pilot components mounted outside the fence as required.

C.1.7 Post Purge System

Callidus has included a post purge system that will purge the flare burners after each flaring episodes. The post purge will open the purge valve downstream of the staging valve each time the staging valve closes.

D. UTILITIES

D.1 PILOTS: 85,000 Btu/hr (24.9 watts) of natural gas @ 30 psig (2 Bar) for each pilot (continuous).

D.2 ELECTRICAL: Approximately 2 kilowatts at 120 volt, 60 cycle, 1 phase for each spark ignitor, ignition transformer, and control system.

D.3 PURGE: Purge gas can be any gas that does not go to dew point at purge conditions and does not contain oxygen.

	Continuous (Nm^3/hr)	Destage Post-Purge (Nm^3/hr)
Multipoint Ground Flare	5	600

"Destage Post-Purge" is the highest flow rate for a single destaging row. It is possible that multiple rows can destage simultaneously. Purge rates are preliminary, and will be finalized in detailed engineering. Nitrogen is the recommended continuous and Post-Purge gas.

It is assumed that all continuously on-service stages will be purged down the flare header with plant purge. Because they are continuously on-service, post-purge is not required. No purge system is included for continuously on-service flares.

D.4 FLAME FRONT GENERATOR:

150 SCFH (5.58 Nm^3/hr) fuel gas at 50 PSIG (3.44 Bar) minimum supply pressure.
1500 SCFH (55.8 Nm^3/hr) instrument air at 50 PSIG (3.44 Bar) minimum supply pressure.
Flame Front Generator air and fuel gas are required intermittently during ignition only.

ATKINS

Appendix F

Callidus Technologies - Proposal to Freeport LNG Dated September 12, 2011

Proposed NGL Flare

CALLIDUS TECHNOLOGIES
by Honeywell

Automation & Control Solutions
Honeywell
7130 South Lewis Avenue
Suite 335
Tulsa, OK 74136

Main Line: 918-496-7599

September 12, 2011

Freeport LNG

RE: Your Reference – 1009-000-SP-0180-001
Callidus File No. F-1109-090047-HT

Attention: Steve Chafin
Email: schafin@freeportlng.com

Mr. Chafin:

For more than 35 years the Callidus team has participated in and have been responsible for design, start-up and maintenance of numerous flare systems. Of particular importance to your project is the team's experience with integrated flare systems, specifically, development and start-up of hundreds of flare applications.

Callidus sincerely appreciates the opportunity to present the following proposal and we appreciate the time and effort you will invest to review and evaluate our offering. When appropriate, Callidus prefers to visit your facility in order to more completely present the technical advantages and unique features of our technology. Our presentation will also include a review of Callidus' approach to your particular application, further outline of personnel background and experience and answers to any questions you may have.

Not only are the unique qualifications of the Callidus team well matched to your project, but also the entire Callidus staff is totally committed to providing technically competent and timely completion of any work committed to us. Should questions arise for which immediate answers are required, please feel free to contact us at our Tulsa offices or our local representative, Jack Hornsby with EnviroPro at 281.236.5029

With these comments in mind, we are pleased to offer the attached proposal.

Best Regards,

Ryan Pilkington
Applications Engineer
Direct Phone: (918) 523-2159
Email: Ryan.Pilkington@Honeywell.com

cc: Sales Office
Customer copies

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A. PROCESS SPECIFICATIONS

Case 1	Maximum Design	Smokeless Design
Flowrate (lb/hr)	50,890	50,890
Required Pressure at flare inlet (psig)	11.014	11.014
Molecular Weight	51.83	51.83
LHV (btu/scf)	2695	2695
Temperature (°F)	132.3	132.3

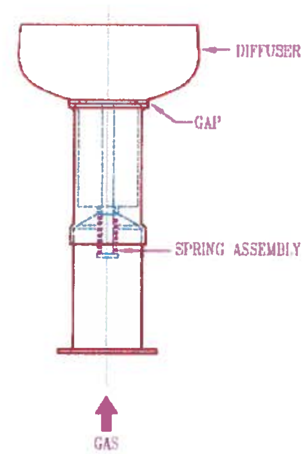
Case 2	Maximum Design	Smokeless Design
Flowrate (lb/hr)	59,799	59,799
Required Pressure at flare inlet (psig)	14.134	14.134
Molecular Weight	75.9	75.9
LHV (btu/scf)	3,898.6	3,898.6
Temperature (°F)	327.9	327.9

Both cases are 100% smokeless to Ringlemann 0

B. ENGINEERING ASSESSMENT

HEMISFLARE

The key to successful smokeless burning of waste material is to properly design the burner system to achieve optimum mixing of waste gas and air. Of particular importance is obtaining a high enough mechanical kinetic energy level in the combustion zone to promote mixing. This energy level can be generated through use of the waste gas pressure and, if necessary, modifying the burner topography to increase the ratio of gas/air interface area periphery to gas outlet area. The required energy level can be approximated by using the summation of the VDP of the fluids in the combustion zone. This value of the summation of the VDP's must reach some constant level for a given waste composition, burner design, environmental conditions, and other variables in order to provide smokeless operation.



Of particular importance is the design of the burner and its ability to provide mixing over the widest possible range of flow rates. The burner design must be executed to provide inspirated airflow and gas flow in proportion to each other. In addition, the burner design must provide for stability of the waste gas under greatly varying flow conditions. This is achieved in the Callidus HEMISFLARE design by controlling the outlet area of the gas exit by an internal spring system (which is constantly cooled by the flowing gas) ensuring stable combustion through a wide range of compositions and turndowns. During periods of low flow, the tip is virtually closed thus greatly lowering the required purge rate. As the gas pressure rises, however, this pressure forces the gas exit area to increase (the force generated by the gas pressure acting on the top "diffuser" element acts against the restraining spring pack), thus allowing more gas to flow up to the maximum capability of the burner.

In addition to the variable flow feature, the HEMISFLARE design ensures that only a thin film of gas is presented to the air. Also, by using an aerodynamic effect that is utilized in aircraft design, there is a strong negative pressure exerted by the gas flow on the ambient air that creates much more intense mixing than can be achieved with a simple nozzle system that relies solely on momentum entrainment.

With the HEMISFLARE, a burner staging system is not required. (Such a system proportions the number of burners in service to the flow rate of waste gas which must be flared. Improper staging can result in smoking burners or, in the case of steam-assisted burners, flameout due to over-steaming.) The burners are self-adjusting.

Pilots for the Callidus flares are the result of intensive testing to improve pilot operation in several aspects.

- Wind stability. All Callidus pilots are equipped with windshields over the mixers, in addition to the wind stability designed in with the matched mixer/tip combination - both are investment cast for quality control and longevity.

- Longevity. The pilot gas tip, flame shield and thermocouple mounting well, are all investment castings of CK-20 material. CK-20 is a casting version of 310SS. The castings metallurgy, the lack of forming stresses, and the metal thickness combine to make a long-lived pilot.

- Thermocouple life. Callidus testing has selected a thermocouple placement to maximize response in all weather conditions, as well as minimize the exposure to direct flame. The cast thermowell is designed to assure consistent thermocouple placement.

C. SCOPE OF SUPPLY

C.1 HEMISFLARE FLARE TIP

One (1) Callidus "HEMISFLARE" high pressure flare tip consisting of Two (2) 8" HEMISFLARE tips. The tip is 10 feet 0 inches overall length, constructed of 316SS. The flare has the following features:

- Two (2) high-stability flare pilots mounted on free floating brackets to prevent damage due to thermal expansion.
- One 18" carbon steel RFWN flanged inlet connection.
- Pilot mixers mechanically designed to support expected piping load.
- Plug welded brackets to avoid stress cracking.
- Pilot flame shield, gas tip and thermowell for the thermocouple are investment cast of CK-20.
- Simplex type "K" chromel-alumel thermocouple protected with a 310 stainless steel sheath and terminated in a conduit weatherhead for trouble-free and weatherproof connections

C.2 Self Supported Flare Stack

One (1) self supported flare stack to achieve 110 feet overall height. The following items are included as integral parts of the flare system:

- Carbon steel A-36 construction
- One (1) lot of carbon steel pilot gas and ignition piping
- One (1) lot conduit for thermocouple wire

C.3 Liquid Seal Drum

One (1) 6 feet 0 inches outside diameter x 30 feet 0 inches tangent to tangent vertical liquid seal drum. The seal is mounted in the flare stack base.

The following connections are provided on the vessel:

- One (1) 12 inch 150 lb. raised face flanged inlet at approximate elevation 10'-0"
- One (1) 2 inch 150 lb. raised face flanged overflow connection with skimmer
- One (1) 2 inch 150 lb. raised face flanged water inlet

- Two (2) 2 inch 150 lb. raised face flanged bridle connections for customer supplied bridle and level controls
- One (1) 2 inch 150 lb. raised face flanged drain connection
- One (1) 18 inch manway
- Specially designed gas distribution internals to provide the following features:
    - positive back pressure control
    - smooth flow transition
    - flashback control

C.4 Automatic / Manual Flame Front Generator

The flare ignition system proposed is an automatic flame front generator system. The system consists of a panel to which natural gas and air are piped. The panel includes a pressure regulator, hand firing valve, and a pressure gauge for both the air and the gas lines. An individual 1-inch line is required for each pilot. When the thermocouple senses pilot failure of the selected pilot, the flow of air/gas mixture is allowed to fill the 1-inch line to the pilot. In essence, this air/gas mixture forms a fuse between the flame front generator panel and the pilot. A flame front travels through the 1-inch line between the panel and the pilot and provides ignition of the pilot. The system consists of the following major components:

- One (1) pilot fuel gas metering system consisting of a pressure regulator, strainer, needle valve, solenoid valve, pressure gauge.
- One (1) ignition fuel gas metering system consisting of a pressure regulator, strainer, needle valve, solenoid valve, pressure gauge, and a restriction orifice to feed the ignition chamber
- One (1) air metering system consisting of a pressure regulator, strainer, needle valve, solenoid valve, pressure gauge, and a restriction orifice to feed the ignition chamber
- One (1) high voltage ignition transformer and spark plug
- Pilot status is registered by programmable logic controller constantly monitoring the pilot thermocouples
- Loss of pilot indicating lights
- Sight port
- One (1) manual ignition pushbutton
- One (1) 1 inch pilot selector (solenoid) valve per pilot
- One (1) mixing chamber

- One (1) NEMA 4X Z-purge control panel for Class 1, Div II, Group C, D hazardous area
- All components are shop mounted on a back plate with legs

D. UTILITIES

D.1 PILOTS: 85,000 Btu/hr of fuel gas @ 30 psig for each pilot (continuous)

D.2 FLAME FRONT GENERATOR: 150,000 Btu/hr of fuel gas at 15 psig, 1500 SCFH of compressed air at 15 psig (intermittent during ignition of pilot only)

D.3 ELECTRICAL: 120 volt, 60 cycle, 1 phase for spark ignitor and the ignition transformer

D.4 PURGE: Purge gas can be any gas that does not go to dew point at purge conditions and does not contain oxygen. Purge rate required = 26 SCFH

E. OTHER TECHNICAL DATA

E.1 Radiation Information

Radiation levels are shown on the attached plots of radiation at grade versus distance from the base of the flare stack. In addition, the following shows the radiation levels at the specific points of interest specified in the inquiry document. All radiation levels are specified in btu/hr-ft2 units and are +/- 100 btu/hr-ft2.

E.2 NOISE

The expected noise potential of the tip based on the smokeless/ultimate rate is shown in the table below:

OPERATING OPTION	30 FEET FROM BASE OF STACK	500 FEET FROM BASE OF STACK
Maximum Capacity	85 dba	70 dba

Noise levels are +/- 3 dba with the background noise level in each measured frequency 6- 8 dba less at the measured frequency point.

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Purchaser Supplied - General Information

		Note		REV
1	Purchaser		FREEPORT LNG EXPANSION, LP	
2	Reference Number			
3	Client			
4	Project		PRETREATMENT SYSTEM (PTS)	
5	Vendor			
6	Reference Number			
7				
8	Jobsite Location		STRATTON RIDGE, TEXAS	
9	Jobsite Climate		GULF COAST	
10	Unit Tag		FLARE STACK	
11	Equipment Number		6Z-1840	
12	Service		PROCESS FLARE	
13	Quantity Required		ONE	
14	Is Smokeless Required? (Y/N)		YES	
15	Preferred Smokeless Method		NON-ASSISTED	
16	Local Codes		40 CFR, NFPA 59A, 49 CFR 193, 333 CFR 127	
17	Is P&ID Attached? (Y/N)			
18				
19	Ambient Conditions (Design / Normal)		NORMAL	
20	Minimum Temperature, deg F		20	
21	Maximum Temperature, deg F		95	
22	Relative Humidity, %		PREVIOUS PROJECT: SEE GALVESTON DATA	
23	Maximum Wind Speed, mph		PREVIOUS PROJECT: SEE GALVESTON DATA	
24	Predominant Wind, (Y/N) / Direction		PREVIOUS PROJECT: SEE GALVESTON DATA	
25	Peak Solar Radiation, BTU/hr-sq.ft.		316 MAXIMUM INCIDENT	
26	Include Solar w/ Flare Radiation (Y/N)		YES	
27	Jobsite Elevation, ft above sea level		14	
28	Seismic Zone		SEE STRUCTURAL DESIGN (BELOW)	
29				
30	Flare Name			
31	Medium			
32	Product General Scope		100% SMOKELESS	
33			25 WT% LIQUID HANDLING CAPABILITY	
34				
35				
36				
37				
38	Specs			
39	Structural Design		FOR STRUCTURAL SUPPORT DESIGN, ASCE 7-LATEST	
40			CATEGORY III, EXP C, I=1.15, Kzt=1.0, UBC-97, ZONE 0	
41			WIND SPEED: 150 MPH SUSTAINED, 183 MPH BASIC	
42	Mechanical Design		ASME	
43	Electrical		NEC	
44	Non-Destructive Testing		ASME - 10% SPOT RADIOGRAPHY	
45				
46				

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API-537 Flare **Data Sheet** **US Customary Units**	A	8/24/2011	FOR AIR PERMIT	SWC

Purchaser Supplied - General Information

		Note		REV
1	Minimum Flare Height, ft			
2	Anticipated Flare Header Diameter, in			
3	Approx. Flare Header Length, ft			
4	Flare Header Network Volume, cu.ft.			
5	Plot Space Available, Length/Width, ft			
6	Aircraft Warning Lights Required? (Y/N)		YES	
7				
8	Welding Code		ASME	
9	Weld Inspection		ASME	
10	Surface Prep. & Paint Requirements		THREE COAT OFFSHORE PER FLNG SPEC	
11	Special Erection Requirements			
12				
13	Nozzle Loads on Flare Inlet			
14	Fx, Fy, Fz (kips)			
15	Mx, My, Mz (ft-kips)			
16	Special Piping Treatment			
17	Fireproofing			
18	Insulation			
19	Supports			
20	Covering			
21	Heat Tracing (Elec., Steam)			
22				
23	Utilities Available (Design / Normal)			
24	Steam Pressure, psig		N/A	
25	Steam Temperature, deg.F		N/A	
26	Location of Steam Conditions		N/A	
27	Blower Power, Volts / Phase / Freq			
28	Instr. Power, Volts / Phase / Freq		120 V / 1 / 60 HZ; 24 V DC	
29	Electrical Classification, Cl / Gp / Div		CLASS I / GROUP C&D / DIV 2	
30	Instrument Air, psig		100 PSIG NORMAL, 80 PSIG MINIMUM	
31	Plant Air, psig			
32	Nitrogen, psig			
33	Fuel Gas, psig / Case #	11	50 PSIG TO FUEL GAS SKID	
34	Purge Gas, psig / Case #			
35	Utility Costs			
36				
37	Nearby Structures (Distance, Height), ft			
38	Other Active Flares		POTENTIALLY: EXISTING ENCL GRD FLARE	
39	Direction from Proposed Flare		UNKNOWN AT THIS TIME	
40	Heat Release, BTU/hr			
41	Radiant Fraction			
42	Other Inactive Flares			
43	Cooling Towers			
44	Electrical Substations			
45	Property Line			
46				

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PROCESS DESIGN CONDITIONS - PURCHASER

		Note	CASE 1	CASE 2			
1	Design Flare Capacity, lb/hr		50,890	59,799			
2	Smokeless Capacity		0-100%	0-100%			
3	Gas Temperature, deg F		132.3	327.9			
4	Static Pressure at Flare Inlet, psig	8	50 MAX	50 MAX			
5	Flare Inlet Diameter, inches						
6	Veq, SCFH air equivalent						
7	Heat Release, MMBTU/hr						
8	Duration @ Max. Rate, min.						
9	Relief Source		DEBUTANIZER	COND STG			
10	Controlling Case For . . .		LOSS REFLUX	FIRE			
11	**GAS COMPOSITION** (Mole% / Mass%)		mole%	mole%			
12	Methane		1.26				
13	Ethane		4.39				
14	Propane		32.55				
15	Isobutane		32.49	1.89			
16	n-Butane		28.97	15.12			
17	Isopentane		0.26	36.87			
18	n-Pentane		0.01	19.15			
19	Hexane			14.8			
20	Heptane			7.34			
21	Octane			3.35			
22	~~Ethylene~~ R1SH + R2SH +R3SH		0.07	0.10			
23	Propylene						
24	Butylene						
25	Acetylene						
26	Butadiene						
27	Benzene			0.02			
28	Toluene			0.01			
29	Xylene						
30	Hydrogen						
31	Carbon Monoxide						
32	Hydrogen Sulfide						
33	Ammonia						
34	Water Vapor						
35	Nitrogen						
37	Carbon Dioxide						
38	Nonane			1.35			
39							
40	**TOTAL** (should be 100%)		100.00	100.00			
41	Molecular Weight		51.83	75.9			
42	Higher Heating Value, BTU/SCF		3007	4498			
43	Ratio of Specific Heats, Cp/Cv						
44	Viscosity, cp						
45	UEL, % in air						
46	LEL, % in air						

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MECHANICAL DESIGN DATA (PILOTS / IGNITION SYSTEM)

		Note	Purchaser - Specified		REV	Vendor - Proposed / Actual	REV
	PILOTS						
1	Quantity		THREE (3)				
2	Type		BY VENDOR				
3	Rating - Each, BTU/hr						
4	Gas Pressure		BY VENDOR				
5	Inspirator Type						
6	Inspirator Material						
7	Gas Orifice Size, in.						
8	Strainer (Y/N)		YES				
9	Flame Monitors (per pilot / per flare)						
10	Flame Monitor Type	13	FLAME ION ROD				
11	Pilot Fuel Connection Type / Size, in.		150# RFWN	1.5 INCH MIN			
12	Fuel Gas Manifold (Y/N)						
13	Manifold Connection Type / Size, in.						
14	Ignition Connection Type / Size, in.		150# RFWN	1.5 INCH MIN			
15	Retractable Pilots (Y/N)						
16	Retractable Thermocouples (Y/N)						
17							
18							
19							
20	**IGNITION SYSTEM**						
21	Type (FFG / Electronic / Other)		FLAME FRT GEN				
22	Distance from Stack, ft						
23	Automatic / Manual Ignition						
24	Elec. Class., Cl / Gp / Div		CLASS I, GRP C&D, DIV 2				
25	Remote Alarm Contacts - Quantity						
26	Remote Ignition Contact (Y/N)						
27	Pressure Regulators - Quantity						
28	Pressure Gauges - Quantity		YES -				
29	Pilot Selector Valves - Type / Quantity						
30	Pilot Indicator Lights (Y/N)		YES				
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							

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MECHANICAL DESIGN DATA (LIQUID SEAL)

		Note	Purchaser - Specified	REV	Vendor - Proposed / Actual	REV
	LIQUID SEAL					
1	Vessel Diameter, ft					
2	Height / Length (T/T), ft					
3	Material / Thickness, in.					
4	Integral / Separate from stack					
5	Design Code					
6	Code Stamp (Y/N)					
7	Design Pressure, psig					
8	Design Temperature, deg.F					
9	Corrosion Allowance, in.					
10	Seal Depth, in.					
11	Max. Vacuum w/o adding liquid, in. WC					
12	Freeze Protection Type					
13	Connection Type / Size, in. / #					
14	Instrument / Valve Requirements					
15	Special Requirements					
16	Vessel Connections					
17	Flare Gas Inlet Type / Size, in. / #					
18	Flare Gas Outlet Type / Size, in.					
19	Fill Nozzle Type / Size, in. / #					
20	Drain Type / Size, in. / #					
21	Level Gauge Type / Size, in. / #					
22	Level Switch Type / Size, in. / #					
23	Temperature Type / Size, in. / #					
24	Pressure Type / Size, in. / #					
25	Skimmer/Overflow Type / Size, in. / #					
26	Manway Type / Size, in. / #					
27	Skirt Access (Y/N) / Type / Size, in. / #					
28	Skirt Vents (Y/N) / Type / Size, in. / #					
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MECHANICAL DESIGN DATA (KNOCKOUT DRUM)

		Note	Purchaser - Specified	REV	Vendor - Proposed / Actual	REV
	KNOCKOUT DRUM		BY OTHERS			
1	Type (Horiz. / Vert. / Cyclone, ref. RP-521)		HORIZONTAL			
2	Vessel Diameter, ft					
3	Height / Length (T/T), ft					
4	Material / Thickness, in.					
5	Integral / Separate from stack					
6	Design Code					
7	Code Stamp (Y/N)					
8	Design Pressure, psig					
9	Design Temperature, deg.F					
10	Corrosion Allowance, in.					
11	Max. Liquid Level, ft.					
12	Liquid Holdup Volume, cu.ft.					
13	Freeze Protection Type					
14	Connection Type / Size, in. / #					
15	Instrument / Valve Requirements					
16	Special Requirements					
17	Vessel Connections					
18	Flare Gas Inlet Type / Size, in. / #					
19	Flare Gas Outlet Type / Size, in.					
20	Fill Nozzle Type / Size, in. / #					
21	Drain Type / Size, in. / #					
22	Level Gauge Type / Size, in. / #					
23	Level Switch Type / Size, in. / #					
24	Temperature Type / Size, in. / #					
25	Pressure Type / Size, in. / #					
26	Skimmer/Overflow Type / Size, in. / #					
27	Manway Type / Size, in. / #					
28	Skirt Access (Y/N) / Type / Size, in. / #					
29	Skirt Vents (Y/N) / Type / Size, in. / #					
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REQUIRED SYSTEM PERFORMANCE - PURCHASER

		Note	Specified	REV	Based on Case / Flow	REV
	FLOW PERFORMANCE					
1	Hydraulic Capacity, lb/hr		59,799			
2	Static Inlet Pressure (@flare stack inlet), psig		50 MAX			
3	Peak Exit Velocity, ft/s					
4	Peak Mach Number	4	0.5 MAX			
5						
6						
7	**RADIATION PERFORMANCE**					
8	Peak Radiation at Grade, BTU/hr-ft^2	1,2,3	SEE NOTES			
9	Distance to Peak Radiation, ft					
10	Distance to ______ BTU/hr-ft^2, ft					
11	Distance to ______ BTU/hr-ft^2, ft					
12	Radiant Fraction	6	≥ 0.3			
13						
14	**NOISE PERFORMANCE**					
15	SPL at Flare Base, dBA	5	≤ 115 @ GRADE			
16	SPL at ______ ft from base, dBA					
17	SPL at ______ ft from base, dBA					
18						
19						
20	**SMOKELESS PERFORMANCE**					
21	Smokeless Capacity		0-100%			
22	Smokeless Definition (R0 / R1 / R2)	10	R1 OR BETTER			
23	Opacity	10	≤20%			
24	**SMOKELESS STEAM CONSUMPTION**					
25	Primary Steam, lb/hr		N/A			
26	Secondary Steam, lb/hr		N/A			
27	Tertiary Steam, lb/hr		N/A			
28						
29	Max. Total Steam, lb/hr		N/A			
30	Continuous Steam, lb/hr		N/A			
31	S/HC ratio @ Design Smokeless Rate		N/A			
32	**SMOKELESS AIR REQUIREMENTS**					
33	Continuous (Min.), HP		N/A			
34	Second Stage, HP		N/A			
35	Third Stage, HP		N/A			
36	Max. Total Power, HP		N/A			
37	Design Air Capacity, CFM		N/A			
38	Design Blower Pressure, in.w.c.					
39	**UTILITY CONSUMPTION**					
40	Purge Gas, SCFH		BY VENDOR			
41	Pilot Gas, SCFH		BY VENDOR			
42	Ignition Gas, SCFH (Intermittent)					
43	Ignition Air, SCFH (Intermittent)					
44	Assist Gas, SCFH / lb/hr waste					
45	Supplemental Gas, SCFH					

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API-537 Flare Data Sheet US Customary Units	A	8/24/2011	FOR AIR PERMIT	SWC

PREDICTED SYSTEM PERFORMANCE - VENDOR

		Note	Predicted	REV	Based on Case / Flow	REV
	FLOW PERFORMANCE					
1	Hydraulic Capacity, lb/hr					
2	Static Inlet Pressure, psig					
3	Peak Exit Velocity, ft/s					
4	Peak Mach Number					
5						
6						
7	**RADIATION PERFORMANCE**					
8	Peak Radiation at Grade, BTU/hr-ft^2					
9	Distance to Peak Radiation, ft					
10	Distance to ________ BTU/hr-ft^2, ft					
11	Distance to ________ BTU/hr-ft^2, ft					
12						
13						
14	**NOISE PERFORMANCE**					
15	SPL at Flare Base, dBA					
16	SPL at ________ ft from base, dBA					
17	SPL at ________ ft from base, dBA					
18						
19						
20	**SMOKELESS PERFORMANCE**					
21	Smokeless Capacity, lb/hr					
22	Smokeless Definition (R0 / R1 / R2)					
23						
24	**SMOKELESS STEAM CONSUMPTION**					
25	Primary Steam, lb/hr					
26	Secondary Steam, lb/hr					
27	Tertiary Steam, lb/hr					
28						
29	Max. Total Steam, lb/hr					
30	Continuous Steam, lb/hr					
31	S/HC ratio @ Design Smokeless Rate					
32	**SMOKELESS AIR REQUIREMENTS**					
33	Continuous (Min.), HP					
34	Second Stage, HP					
35	Third Stage, HP					
36	Max. Total Power, HP					
37	Design Air Capacity, CFM					
38	Design Blower Pressure, in.w.c.					
39	**UTILITY CONSUMPTION**					
40	Purge Gas, SCFH					
41	Pilot Gas, SCFH					
42	Ignition Gas, SCFH (Intermittent)					
43	Ignition Air, SCFH (Intermittent)					
44	Assist Gas, SCFH / lb/hr waste					
45	Supplemental Gas, SCFH					
46						

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MECHANICAL DESIGN DATA (FLARE BURNER)

		Note	Purchaser - Specified	REV	Vendor - Proposed / Actual	REV
	FLARE BURNER BODY					
1	Model		BY VENDOR			
2	Nozzle Type		BY VENDOR			
3	Quantity of Nozzles / Size, inch		BY VENDOR			
4	Smokeless Method		SONIC			
5	Overall Length, ft					
6	Upper Section Length, ft		5			
7	Material / Diam. / Thickness, in		316 SS			
8	Lower Section Length, ft		5			
9	Material / Diam. / Thickness, in		316 SS			
10	Connection Type / Size, in					
11	Lining, Length, ft					
12	Material / Thickness					
13	Muffler, Length / Diameter, ft					
14	Windshield, Type / Material					
15	Flame Retention, (Y/N) / Material					
16						
17						
18						
19	**STEAM ASSIST EQUIPMENT**					
20	Primary Steam, Material		N/A			
21	Connection Type / Size, in		N/A			
22						
23	Secondary Steam, Material		N/A			
24	Connection Type / Size, in		N/A			
25						
26	Tertiary Steam, Material		N/A			
27	Connection Type / Size, in		N/A			
28						
29						
30						
31						
32	**AIR ASSIST EQUIPMENT**					
33	Air Plenum Length, ft		N/A			
34	Air Plenum Diameter, in		N/A			
35	Connection Type / Size, in		N/A			
36						
37						
38						
39						
40						
41						
42						
43						

FREEPORT LNG	Project Number	1009	Item Number	6Z-1840
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MECHANICAL DESIGN DATA (PURGE DEVICE / STACK)

		Note	Purchaser - Specified	REV	Vendor - Proposed / Actual	REV
	PURGE CONSERVATION DEVICE					
1	Type (Buoyancy / Velocity / None)					
2	Outside Diameter, in					
3	Overall Length, ft					
4	Material / Thickness					
5	Inlet Type / Size, in.					
6	Outlet Type / Size, in.					
7	Drain Type / Size, in.					
8	Loop Seal Depth, in. (Ref. API RP-521)					
9						
10	**STACK**		CODE PER AISC			
11	Overall Height, ft.	1,2,3	BY VENDOR			
12	Support Method					
13	Design Pressure, psig		125 PSIG			
14	Design Temperature, deg.F		-20 / 650			
15	Riser Material		CS			
16	Upper Section Length, ft					
17	Material / Diam. / Thickness, in.					
18	Middle Section Length, ft					
19	Material / Diam. / Thickness, in.					
20	Lower Section Length, ft					
21	Material / Diam. / Thickness, in.					
22	Inlet Type / Size, in.					
23	Drain Type / Size, in.					
24	Derrick Base Shape / Size, ft					
25	Guy Wire Dead Man Radius, ft					
26						
27						
28						
29	**PIPING ON STACK**					
30	Pilot Gas Lines - Quantity					
31	Material / Size (in) / Schedule					
32	Ignition Lines - Quantity					
33	Material / Size (in) / Schedule					
34	Primary Steam - Mat'l / Size / Sched		N/A			
35	Secondary Steam - Mat'l / Size / Sched		N/A			
36	Tertiary Steam - Mat'l / Size / Sched		N/A			
37						
38	Drain Line - Mat'l / Size / Sched					
39	Assist Gas Line - Mat'l / Size / Sched		N/A			
40	T/C Conduit - Mat'l / Size, in.					
41	Ignition / Power Conduit - Mat'l / Size, in.					
42	ACWL Power Conduit - Mat'l / Size, in					
43						
44						
45						
46						

FREEPORT LNG	Project Number	1009	Item Number	6Z-1840
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	MECHANICAL DESIGN DATA (ANCILLARIES)	Note	Purchaser - Specified	REV	Vendor - Proposed / Actual	REV
	AIR ASSIST BLOWER SYSTEM		N/A			
1	Fan Quantity		N/A			
2	Fan Type / Material		N/A			
3	Fan Location		N/A			
4	Damper Quantity		N/A			
5	Damper Control Required / Included		N/A			
6	Motor Type / Speed		N/A			
7	Motor Enclosure		N/A			
8	Motor Nameplate HP		N/A			
9	Motor / Fan - Lubrication		N/A			
10	Max. Motor Current - Winter, amps		N/A			
11	Supplemental Requirements		N/A			
12						
13						
14						
15	**LADDERS & PLATFORMS**		CODE PER OSHA			
16	Top Platform, Deg. / Size, ft					
17	Step-off Platforms, Quantity					
18	Buoyancy Seal Access (Y/N)					
19	Instrument Access, Quantity					
20	Ladders Type					
21	Material / Finish					
22	L&P Specification					
23						
24	**AIRCRAFT WARNING SYSTEM**		PER LOCAL CODE			
25	Quantity	12	SIX (6)			
26	Location					
27	Color / Type (Strobe / Beacon / Paint)		3 BEACON, 3 DBL OBS			
28	Retractable (Y/N)		YES			
29	Painting Specification					
30						
31	**EST. EQUIPMENT WEIGHTS, LB**					
32	Flare Tip					
33	Purge Reduction Device					
34	Gas/Air Risers + Piping					
35	Support System					
36	Ladders & Platforms					
37	Liquid Seal					
38	Knockout Drum					
39	Control Panels					
40						
41	**SMOKE SUPPRESSION CONTROL**					
42	Flare Gas Flow Detector					
43	Smoke Detector					
44	Control Strategy (Auto / Manual)					
45						

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GENERAL NOTES

PAGE NO.	NOTE NO.		REV NO.
Page 7, 10	1	RADIATION CALCULATIONS SHALL BE BASED UPON API METHOD WITH A REFERENCE POINT FIVE (5) FEET ABOVE GRADE (HEAD HEIGHT OF WORKING PERSONNEL). VENDOR SHALL SUPPLY RADIATION PLOT (ISOPLETH).	
Page 7, 10	2	MAXIMUM RADIATION LEVEL IS NOT TO EXCEED 1500 BTU/HR/FT2 INCLUSIVE OF SOLAR RADIATION OR;	
Page 7, 10	3	MAXIMUM RADIATION LEVEL IS NOT TO EXCEED 500 BTU/HR/FT2 EXCLUSIVE OF SOLAR RADIATION @ 175 FEET	
Page 7	4	MACH NUMBERS GREATER THAN 0.5 SHALL BE SUPPORTED WITH BACKUP DOCUMENTATION.	
Page 7	5	MAXIMUM NOISE LEVEL ANYWHERE AT GRADE.	
Page 7	6	VENDOR SHALL SUPPLY DATA TO VALIDATE LOWER RADIANT FRACTION VALUES FOR THE FLARE TIP OR PROVIDE FLARE TESTING.	
Page 3	8	VENDOR SHALL CLEARLY PROVIDE PRESSURE REQUIRED AT INLET FLANGE CONNECTION AS A FUNCTION OF FLARE THROUGHPUT (MASS FLOW - LB/HR).	
Page 7	10	FLOW MUST BE SMOKELESS (R1 OR BETTER) FROM PURGE TO PEAK FLOW. R0 FROM (VENDOR) LB/HR AND ABOVE.	
Page 2	11	FUEL GAS COMPOSITION: LATER	
Page 11	12	RADIATION SHIELDS SHALL BE PROVIDED TO PROTECT LIGHTS FROM FLAME RADIATION.	
Page 4	13	OPTION FOR THERMOCOUPLE BACKUP SHALL BE PROVIDED.	

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Appendix G

Copy of Requested Email Correspondence

Preliminary FLNG Liquefaction Project Info - CONFIDENTIAL
Ruben.Velasquez
to:
MDakas
10/07/2011 11:49 AM
Show Details

Melissa,

Attached is a copy of preliminary information for Freeport LNG's Liquefaction Project. This information is subject to verification by FLNG, so some files may change. However, it will give you an opportunity to go through the data and see where we are compared to your data needs listing.

Please provide a listing of information we still need from me by Tuesday, if possible, so we can discuss.

Thanks for your time yesterday!
Ruben

Ruben I. Velasquez, P.E.
Senior Engineer - Air Quality

ATKINS
6504 Bridge Point Parkway, Suite 200, Austin, TX 78730 | Tel: +1 (512) 342 3395 | Fax: +1 (512) 327 6840 | Cell: +1 (512) 923 0864 |
Email: Ruben.Velasquez@atkinsglobal.com | Web: www.atkinsglobal.com/northamerica
www.atkinsglobal.com

File(s) will be available for download until **12 October 2011**:

File: FLNG Liquefaction Project Info to Trinity RIV 10-7-2011.zip, 33,731.84 KB

You have received attachment link(s) within this email sent via Atkins SendIT. To retrieve the attachment(s), please click on the link(s).

New Users: Click on the attachment link to register and create a unique password. To download a userguide, visit http://sendit.pbsj.com
Accellion File Transfer

FLNG PTS - Fugitive Emissions Count - 3 Trains
Velasquez, Ruben I
to:
Melissa Dakas
10/13/2011 06:24 PM
Show Details

Melissa,
Here are Fugitive Equipment Counts for the Pretreatment Trains – total for 3 trains.
Ruben

Ruben I. Velasquez, P.E.
Senior Engineer - Air Quality

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6504 Bridge Point Parkway, Suite 200, Austin, TX 78730 | Tel: +1 (512) 342 3395 | Fax: +1 (512) 327 2453 | Cell: +1 (512) 923 0864 |
Email: Ruben.Velasquez@atkinsglobal.com | Web: www.atkinsglobal.com/northamerica www.atkinsglobal.com

Component Name	Stream Type	VOC Number of Components	Ammonia Number of Components	From H&M Balance Stream Number
Valves	Gas/Vapor	2947	159	1,2,3,5,6,7,8,9,10,16,20,23,24,27,28,40,41,42
	Light Liquid	697	691	25,26,28,31,32,33,34,35,36,37,38,39
	Heavy Liquid	434		H6,H7,H10,H11,H13,H2,H3,H12,H14,H4,H5,H8,H9,H27,H20,H21,H22,H16,H23
Pumps	Light Liquid	9	20	
	Heavy Liquid	5	12	H1
Flanges/Connectors	Gas/Vapor	6382	834	
	Light Liquid	1424	1355	
	Heavy Liquid	1161		
Compressors		24		12,13
Relief Valve (Gas/Vapor)		115	23	
Open-ended Lines				
Sampling Connections		9		

Freeport LNG Liquefaction Project
Quintana Island, Texas
FLEX Project No. 1008
CB&I Project No. 179810

Preliminary Flange and Valve Count

Reference - Liquefaction Unit Only	Total
Description	
FLANGE CONNECTIONS	
Size up to 1.5"	1,231
Size > 1.5" to 3"	682
Size > 3" to 6"	497
Size > 6" to 12"	530
Size > 12" to 18"	20
Size > 18" to 24"	18
Size > 24" to 30"	4
Size > 30" to 42"	18
Size > 42" to 60"	14
Size > 60" to 72"	4
	3,017
MANUAL AND AUTOMATED VALVES	
Size up to 1.5"	616
Size > 1.5" to 3"	341
Size > 3" to 6"	248
Size > 6" to 12"	265
Size > 12" to 18"	10
Size > 18" to 24"	9
Size > 24" to 30"	2
Size > 30" to 42"	9
Size > 42" to 60"	7
Size > 60" to 72"	2
	1,509

Approximate percent by Phase:

Liquid	24%
2 Phase	12%
Vapor	64%