Prevention of Significant Deterioration Greenhouse Gas Air Permit Application

Lavaca Bay LNG Project
Port Lavaca-Point Comfort, Texas

June 2014

Submitted to:

U.S. Environmental Protection Agency – Region 6
Multimedia Planning and Permitting Division
Fountain Place 12th Floor, Suite 1200
1445 Ross Avenue
Dallas, Texas 75202-2733

Texas Commission on Environmental Quality
12100 Park 35 Circle, Bldg. C
Austin, Texas 78753

Submitted by:

Excelerate Liquefaction Operations (Port Lavaca), LLC
1450 Lake Robbins Drive, Suite 200
The Woodlands, TX 77380

Prepared by:

TETRA TECH

Tetra Tech, Inc.
160 Federal Street, 3rd Floor
Boston, MA 02110

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ACRONYMS AND ABBREVIATIONS

°C	degree Celsius
°F	degree Fahrenheit
AVO	Auditory, Visual, and Olfactory
BACT	Best Available Control Technology
BOG	boil-off gas
Btu	British thermal unit
Btu/kWh	British thermal units per kilowatt-hour
CAA	Clean Air Act
CCS	carbon capture and storage
CFR	Code of Federal Regulations
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
DLE	Dry Low Emissions
DOE	U.S. Department of Energy
ELO	Excelerate Liquefaction Operations
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPNs	Emission Point Numbers
EAB	Environmental Appeals Board
FIP	Federal Implementation Plan
FLSO	floating liquefaction, storage, and offloading unit
GHG	greenhouse gas
GTG	gas turbine generator
GTT	Gaztransport & Technigaz SA
GWP	global warming potential
HFC	hydrofluorocarbon
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid
HHV	higher heating value
hp	horsepower
HRSG	heat recovery steam generator
IGG	inert gas generator
INGAA	Interstate Natural Gas Association of America
ISO	International Organization for Standardization
kg	kilogram
kW	kilowatt
kWh	kilowatt-hour
LAER	Lowest Achievable Emission Rate
lb	pound
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
lb/MWh	pounds per megawatt-hour
LDAR	Leak Detection and Repair
LHV	lower heating value
LNG	liquified natural gas
LNGCs	LNG carriers

m^3	cubic meters
MEA	monoethanolamine
MMBtu	million British thermal units
MMBtu/hr	million British thermal units per hour
MMscf	million standard cubic feet
MSC	Matagorda Ship Channel
MTPA	million tons per annum
MW	megawatt
MWh	megawatt-hour
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
O_2	oxygen
PFC	perfluorocarbon
PM	particulate matter
PM_{10}	particulate matter < 10 microns in diameter
$PM_{2.5}$	particulate matter < 2.5 microns in diameter
Port	Port of Port Lavaca-Point Comfort
ppmvd	parts per million by volume, dry basis
Project	Lavaca Bay LNG Project
PSD	Prevention of Significant Deterioration
PVEC	Pioneer Valley Energy Center
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
SAC	single annular combustor
SF_6	sulfur hexafluoride
SIP	State Implementation Plan
SO_2	sulfur dioxide
SOAH	State Office of Administrative Hearings
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
tpy	tons per year
UHC	unburned hydrocarbons
ULSD	ultra-low sulfur diesel oil
VOC	volatile organic compound
WHRU	waste heat recovery unit
WLE	Wet Low Emissions

1.0 INTRODUCTION

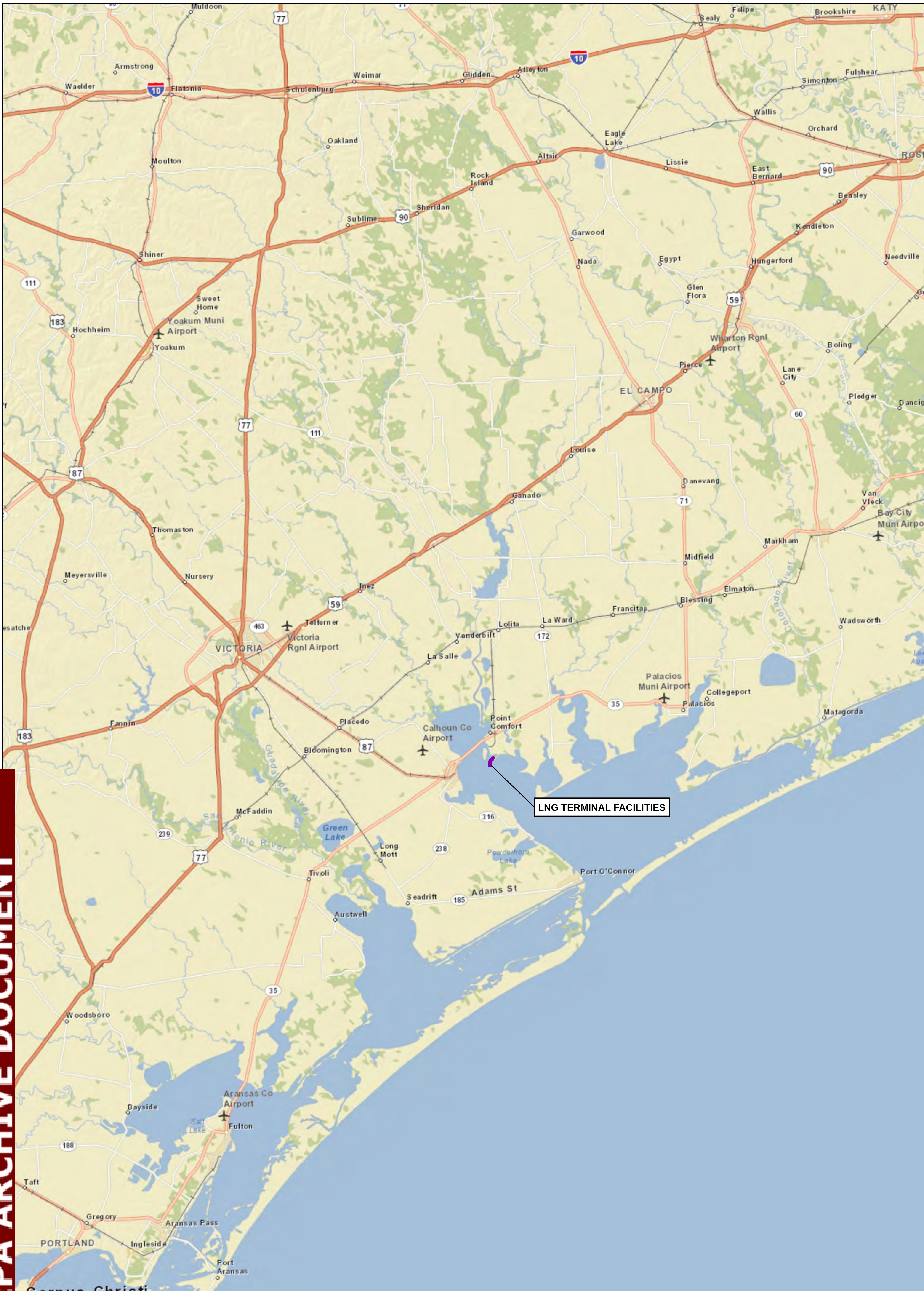
Excelerate Liquefaction Operations (Port Lavaca), LLC (herein after referred to as ELO Port Lavaca) is proposing to operate the Lavaca Bay LNG Project (Project) in Calhoun County, Texas. The Project will include liquefied natural gas (LNG) terminal facilities, consisting of both onshore facilities and marine facilities, to be located on a parcel of land on the South Peninsula of Point Comfort within the Port of Port Lavaca-Point Comfort (Port). Figure 1-1 shows the general site location.

The Project will be constructed in two phases. Phase 1 will include construction of a single Floating Liquefaction, Storage, and Offloading unit (FLSO) that will have a storage capacity of approximately 251,000 cubic meters (m^3) of LNG and the nominal design capacity to produce four million tons per annum (MTPA) and a peak capacity to produce up to five MTPA of LNG. The first phase will also include construction of the marine infrastructure required for the first FLSO and construction of the onshore pre-treatment facilities and infrastructure required for the first FLSO. Phase 2 will consist of construction of a second FLSO and the marine and onshore facilities and infrastructure required for the second FLSO. Phase 2 will essentially double the LNG production capacity to a nominal design capacity of eight MTPA and a peak capacity of up to ten MTPA. ELO Port Lavaca intends to permit both phases simultaneously since it anticipates no significant break in construction between the phases.

Potential emissions of greenhouse gases (GHG) from the Project are subject to Prevention of Significant Deterioration (PSD) review. Under a Federal Implementation Plan (FIP) issued on December 23, 2010, the U.S. Environmental Protection Agency (EPA) is currently the permitting authority for major sources of GHG emissions in Texas.[1] However, the Texas Commission on Environmental Quality (TCEQ) has adopted rule changes to its State Implementation Plan (SIP) that, once approved by EPA, will allow TCEQ to become the permitting authority for major sources of GHG emissions in the state. Therefore, this PSD air permit application, which addresses only the Project's GHG emissions, has been submitted to EPA and TCEQ concurrently consistent with EPA's proposed "Transition Process for Pending GHG PSD Permit Applications."[2]

TCEQ is currently the permitting authority for all other PSD pollutants. Therefore, a separate PSD and State air permit application (Permit Application Nos. PSD-TX-1412 and 120056) was submitted to TCEQ on May 15, 2014 to address the non-GHG pollutants subject to PSD review for the Project, which include carbon monoxide (CO), nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter (PM), including particulate matter less than 10 microns (PM_{10}) and 2.5 microns ($PM_{2.5}$), volatile organic compounds (VOC), and sulfuric acid mist (H_2SO_4). A review copy of the May 15, 2014 PSD non-GHG air permit application was also filed with EPA Region 6.

[1] 75 FR 82365, Dec. 30, 2010.
[2] U.S. Environmental Protection Agency (EPA), "Transition Process for Pending GHG PSD Permit Applications and Issued GHG PSD Permits upon Rescission of the Texas GHG PSD FIP" (Dallas, TX: EPA Region 6, Office of Air and Radiation, February 4, 2014), http://www.epa.gov/region6/6pd/air/pd-r/ghg/tx-ghg-psd-proposedapproval-ghg.pdf



LNG Terminal Facilities

Lavaca Bay LNG Project
Calhoun and Jackson Counties, Texas

Figure 1-1
General Location Map

N

0 2.5 5 10 15 20
Standard Miles

Path: P:\Excelerate\Lavaca Bay Floating Liquefaction\11_GIS\GIS\Spatial\MXD\Air_Permit_Application\20130730_Fig1_1_General_Location.mxd

To facilitate EPA's review of this PSD GHG air permit application, individuals familiar with both the Project and the preparation of this application are identified below. EPA should contact these individuals if additional information or clarification is required during the review process.

ELO Port Lavaca Environmental Contact:

Ernest Ladkani
Excelerate Liquefaction Operations (Port Lavaca), LLC
1450 Lake Robbins Drive, Suite 200
The Woodlands, TX 77380
(832) 813-7687
ernest.ladkani@excelerateenergy.com

Permitting Consultants:

Keith Kennedy
Tetra Tech
160 Federal Street, 3rd Floor
Boston, MA 02110
Telephone (617) 803-7809
keith.kennedy@tetratech.com

Chris L. Williams
Tetra Tech
160 Federal Street, 3rd Floor
Boston, MA 02110
Telephone (617) 443-7568
chris.l.williams@tetratech.com

Application Fee

PSD air permit applications submitted to TCEQ are required to include an application fee based on the estimated capital cost of the project. Because EPA, rather than TCEQ, is currently the PSD permitting authority for GHG emissions in Texas, no application fee is included with this PSD GHG permit application. Furthermore, ELO Port Lavaca has already submitted the maximum required application fee of $75,000, along with an original signed copy of TCEQ Table 30, Estimated Capital Cost and Fee Verification, as part of the the PSD non-GHG air permit application submitted to TCEQ on May 15, 2014. Should TCEQ become the PSD permitting authority for GHG emissions prior to issuance of a GHG permit for the Project, no further application fee should be required.

Professional Engineer Seal

In the event that TCEQ becomes the PSD permitting authority for GHG emissions prior to the issuance of a GHG permit for the Project, this application will be subject to the filing requirements of 30 Texas Administrative Code (TAC) § 116.110(f), which requires projects with an estimated capital cost greater than $2,000,000 to submit air permit applications under the seal of a Texas licensed professional engineer. Therefore, ELO Port Lavaca is submitting this application under the seal of George S. Lipka, P.E.

Organization of Documents

EPA Region 6 hosted a planning meeting with ELO Port Lavaca on April 30, 2013, in which EPA agreed that certain TCEQ application forms could be used as part of the PSD GHG permit application. This introductory section includes the following documents with original signatures:

- TCEQ Form PI-1, General Application for Air Preconstruction Permit; and
- Professional Engineer Seal.

(Signed copies of two other TCEQ forms, the Core Data Form, and Table 30, the Estimated Capital Cost and Fee Verification, can be found in the PSD non-GHG pollutant air permit application submitted to TCEQ on May 15, 2014.)

Supporting information for this application is organized into five additional sections, plus appendices:

- Section 2 – Project Description including Plot Plan and Process Flow Diagram;
- Section 3 – GHG Emissions;
- Section 4 – Regulatory Review and Applicability;
- Section 5 – Best Available Control Technology Analysis;
- Section 6 – References;
- Appendix A – TCEQ Application Tables;
- Appendix B – Emission Calculations; and
- Appendix C – Equipment Performance Data.

TCEQ Form PI-1, General Application for Air Preconstruction Permit

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

Important Note: The agency requires that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued and no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: Excelerate Liquefaction Operations (Port Lavaca), LLC		
Texas Secretary of State Charter/Registration Number (if applicable): 32051300690		
B. Company Official Contact Name: Mike Trammel		
Title: Vice President – Government and Environmental Affairs		
Mailing Address: 1450 Lake Robbins Drive, Suite 200		
City: The Woodlands	State: TX	ZIP Code: 77380
Telephone No.: 832-813-7100	Fax No.: 832-813-7103	E-mail Address: Mike.Trammel@excelerateenergy.com
C. Technical Contact Name: Ernest Ladkani		
Title: Senior Manager – Environmental Permitting/Compliance		
Company Name: Excelerate Energy, L.P.		
Mailing Address: 1450 Lake Robbins Drive, Suite 200		
City: The Woodlands	State: TX	ZIP Code: 77380
Telephone No.: 832-813-7687	Fax No.: 832-813-7103	E-mail Address: Ernest.Ladkani@excelerateenergy.com
D. Site Name: Lavaca Bay LNG Project		
E. Area Name/Type of Facility: Liquefied natural gas (LNG) terminal		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Liquefaction, storage and export of LNG		
Principal Standard Industrial Classification Code (SIC): 4925		
Principal North American Industry Classification System (NAICS): 221210		
G. Projected Start of Construction Date: 2015		
Projected Start of Operation Date: 2018		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: On FM 1593, approx. 2.4 miles south of intersection with SH 35 in Point Comfort, Texas		
City/Town: Point Comfort	County: Calhoun	ZIP Code: 77971
Latitude (nearest second): 28 deg 37'39"	Longitude (nearest second): 96 deg 33'41"	

I.	**Applicant Information (continued)**	
I.	Account Identification Number (leave blank if new site or facility):	
J.	Core Data Form.	
Is the Core Data Form (Form 10400) attached? If No, provide customer reference number and regulated entity number (complete K and L).		☐ YES ☒ NO
K.	Customer Reference Number (CN): 604576488	
L.	Regulated Entity Number (RN): 107273930	
II.	**General Information**	
A.	Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.	☐ YES ☒ NO
B.	Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.	☐ YES ☒ NO
C.	Number of New Jobs: 470	
D.	Provide the name of the State Senator and State Representative and district numbers for this facility site:	
State Senator: Glen Hegar		District No.: 18
State Representative: Geanie Morrison		District No.: 30
III.	**Type of Permit Action Requested**	
A.	Mark the appropriate box indicating what type of action is requested.	
☒ Initial ☐ Amendment ☐ Revision (30 TAC 116.116(e) ☐ Change of Location ☐ Relocation		
B.	Permit Number (if existing):	
C.	Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)*	
☒ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit		
☒ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source		
☐ Other:		
D.	Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

III.	**Type of Permit Action Requested *(continued)***		
E.	Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.0		☐ YES ☒ NO
1.	Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:			
City:	County:	ZIP Code:	
2.	Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:			
City:	County:	ZIP Code:	
3.	Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO", attach detailed information.		☐ YES ☐ NO
4.	Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?		☐ YES ☐ NO
F.	Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.		
List:			
G.	Are you permitting planned maintenance, startup, and shutdown emissions? If Yes, attach information on any changes to emissions under this application as specified in VII and VIII.		☒ YES ☐ NO
H.	Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) Is this facility located at a site required to obtain a federal operating permit? If Yes, list all associated permit number(s), attach pages as needed).	☐ YES ☒ NO ☐ To be determined (A new federal operating permit application will be submitted.)	
Associated Permit No (s.):			
1.	Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.		
☐ FOP Significant Revision	☐ FOP Minor	☐ Application for an FOP Revision	
☐ Operational Flexibility/Off-Permit Notification		☐ Streamlined Revision for GOP	
☐ To be Determined		☒ None	

III. Type of Permit Action Requested *(continued)*		
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*		
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)***		
☐ GOP Issued	☐ GOP application/revision application submitted or under APD review	
☐ SOP Issued	☐ SOP application/revision application submitted or under APD review	
IV. Public Notice Applicability		
A. Is this a new permit application or a change of location application?		☒ YES ☐ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.		☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?		☐ YES ☒ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?		☐ YES ☒ NO
If Yes, list the affected state(s) and/or Class I Area(s).		
List:		
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.		
1. Is there any change in character of emissions in this application?		☐ YES ☐ NO
2. Is there a new air contaminant in this application?		☐ YES ☐ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?		☐ YES ☐ NO
F. List the total annual emission increases associated with the application ***(List all that apply and attach additional sheets as needed):***		
Carbon Dioxide (CO2): 4,202,710		
Methane (CH4): 483.1		
Nitrous Oxide (N2O): 7.2		
CO2 Equivalents (CO2e): 4,216,932		
Other speciated air contaminants not listed above:		

V. Public Notice Information *(complete if applicable)*		
A. Public Notice Contact Name: Ernest Ladkani		
Title: Senior Manager – Environmental Permitting/Compliance		
Mailing Address: Excelerate Energy, L.P., 1450 Lake Robbins Drive, Suite 200		
City: The Woodlands	State: TX	ZIP Code: 77380
B. Name of the Public Place: Calhoun County Public Library		
Physical Address *(No P.O. Boxes)*: 200 West Mahan St.		
City: Port Lavaca	County: Calhoun	ZIP Code: 77979
The public place has granted authorization to place the application for public viewing and copying.		☒ YES ☐ NO
The public place has internet access available for the public.		☒ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits		
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable: Michael J. Pfeifer		
Mailing Address: 211 S. Ann St. Suite 301		
City: Port Lavaca	State: Texas	ZIP Code: 77979
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located.		
Chief Executive: Mayor Pam Lambden		
Mailing Address: P.O. Box 497		
City: Point Comfort	State: Texas	ZIP Code: 77978
Name of the Indian Governing Body: Not applicable		
Mailing Address: Not applicable		
City:	State:	ZIP Code:

V. Public Notice Information *(complete if applicable) (continued)*		
C. Concrete Batch Plants, PSD, and Nonattainment Permits		
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. *(continued)*		
Name of the Federal Land Manager(s): Not applicable		
D. Bilingual Notice		
Is a bilingual program required by the Texas Education Code in the School District?		☒ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?		☒ YES ☐ NO
If Yes, list which languages are required by the bilingual program?	Spanish	
VI. Small Business Classification *(Required)*		
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?		☐ YES ☒ NO
B. Is the site a major stationary source for federal air quality permitting?		☒ YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?		☒ YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?		☐ YES ☒ NO
VII. Technical Information		
A. The following information must be submitted with your Form PI-1 ***(this is just a checklist to make sure you have included everything)***		
1. ☒ Current Area Map (See Figure 2-1)		
2. ☒ Plot Plan (See Figure 2-2)		
3. ☐ Existing Authorizations		
4. ☒ Process Flow Diagram (See Figure 2-3)		
5. ☒ Process Description		
6. ☒ Maximum Emissions Data and Calculations (See Section 3 and Appendix B)		
7. ☒ Air Permit Application Tables (See Appendix A)		
a. ☒ Table 1(a) (Form 10153) entitled, Emission Point Summary (See Appendix A)		
b. ☒ Table 2 (Form 10155) entitled, Material Balance (See Appendix A)		
c. ☒ Other equipment, process or control device tables (See Appendix A)		
B. Are any schools located within 3,000 feet of this facility?		☐ YES ☒ NO

VII.	**Technical Information**		
C.	Maximum Operating Schedule:		
Hour(s): 24	Day(s): 7	Week(s): 52	Year(s): 8,760
Seasonal Operation? If Yes, please describe in the space provide below.			☐ YES ☒ NO
D.	Have the planned MSS emissions been previously submitted as part of an emissions inventory?		☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.			
E.	Does this application involve any air contaminants for which a disaster review is required?		☐ YES ☒ NO
F.	Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)?		☐ YES ☒ NO
VIII.	**State Regulatory Requirements** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*		
A.	Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?		☒ YES ☐ NO
B.	Will emissions of significant air contaminants from the facility be measured?		☒ YES ☐ NO
C.	Is the Best Available Control Technology (BACT) demonstration attached?		☒ YES ☐ NO
D.	Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?		☒ YES ☐ NO
IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*		
A.	Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?		☒ YES ☐ NO
B.	Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?		☐ YES ☒ NO

IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	
Is the estimated capital cost of the project greater than $2 million dollars?		☒ YES ☐ NO
If Yes, submit the application under the seal of a Texas licensed P.E.		
XI.	**Permit Fee Information**	
Check, Money Order, Transaction Number ,ePay Voucher Number: (Already submitted with PSD non-GHG application.)		Fee Amount: $ 75,000
Paid online?		☐ YES ☒ NO
Company name on check: Excelerate Liquefaction Solutions		
Is a copy of the check or money order attached to the original submittal of this application? (Already submitted with PSD non-GHG application.)		☐ YES ☒ NO ☐ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached? (Already submitted with PSD non-GHG application.)		☐ YES ☒ NO ☐ N/A

TCEQ

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

XII. Delinquent Fees and Penalties

This form will not be processed until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.

XIII. Signature

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

Name: Mike Trammel, Vice President – Government and Environmental Affairs

Signature: Mike Trammel

Original Signature Required

Date: 6/09/2014

Professional Engineer Seal

Professional Engineer Seal

Regulatory Requirement

Pursuant to 30 TAC § 116.110(f), permit applications for projects with an estimated capital cost greater than $2,000,000 must be submitted under the seal of a Texas licensed professional engineer. Therefore, ELO Port Lavaca is submitting this application under the seal of George S. Lipka, P.E.

Signature and Seal

I directly supervised the engineering work products contained in the application forms and supporting information for this PSD GHG Air Permit Application.

To the best of my knowledge, the representations made in this document are accurate and true. By affixing my seal below, I submit that the engineering work and calculations performed in the above listed documents were either performed by myself or under my direct supervision, as defined in Section 131.18 of the Texas Engineering Practice Act, and in compliance with Title 30 of the Texas Administrative Code, Chapter 116, Section 116.110(f).

George S. Lipka	[signature]
P.E. Name	P.E. Signature
Senior Engineer	June 5, 2014
Position/Title	Date
Tetra Tech, Inc.	115302
Company	P.E. Number

2.0 PROJECT DESCRIPTION

The Project will enable the liquefaction of natural gas at a floating liquefaction terminal using Black & Veatch PRICO liquefaction trains to be sited adjacent to a deep-draft shipping channel for which a dredging permit has been issued by the United States Army Corps of Engineers. The natural gas will be liquefied for export as LNG on ocean-going LNG carriers (LNGCs) to foreign markets. Liquefaction of natural gas will occur on two FLSOs, which will be permanently moored at the Project site but capable of relocation. LNGCs arriving to receive LNG from the FLSOs will require a deep-draft shipping channel for arrival at and departure from the FLSOs, and a turning basin and berth pockets to facilitate the loading of LNG. Presented in this section is a summary description of the proposed Project.

2.1 Location

The Project will be located on a parcel of land on the South Peninsula of Point Comfort within the Port area of Lavaca Bay. As shown in Figure 1-1, the site is located on the northeastern side of Lavaca Bay approximately 25 miles southeast of Victoria and 75 miles northeast of Corpus Christi.

The LNG terminal will be located on approximately 110 acres of land. At the present time, approximately 70 acres of upland exists at the site and the remaining 40 acres will be created through the use of dredge spoil from construction of the berths. ELO Port Lavaca will utilize 85 acres (including the 40 acres created through the use of dredge spoil) for LNG terminal operations. The remaining 25 acres will be utilized as a construction staging area. The entire 110 acres will be fenced and secured.

2.2 Process Description

The Project will consist of two main components: 1) marine facilities, including the two FLSOs with the liquefaction equipment, and infrastructure; and 2) onshore facilities, including pre-treatment equipment and infrastructure. Details of each Project component are described below although not all facilities described in this section have GHG emissions.

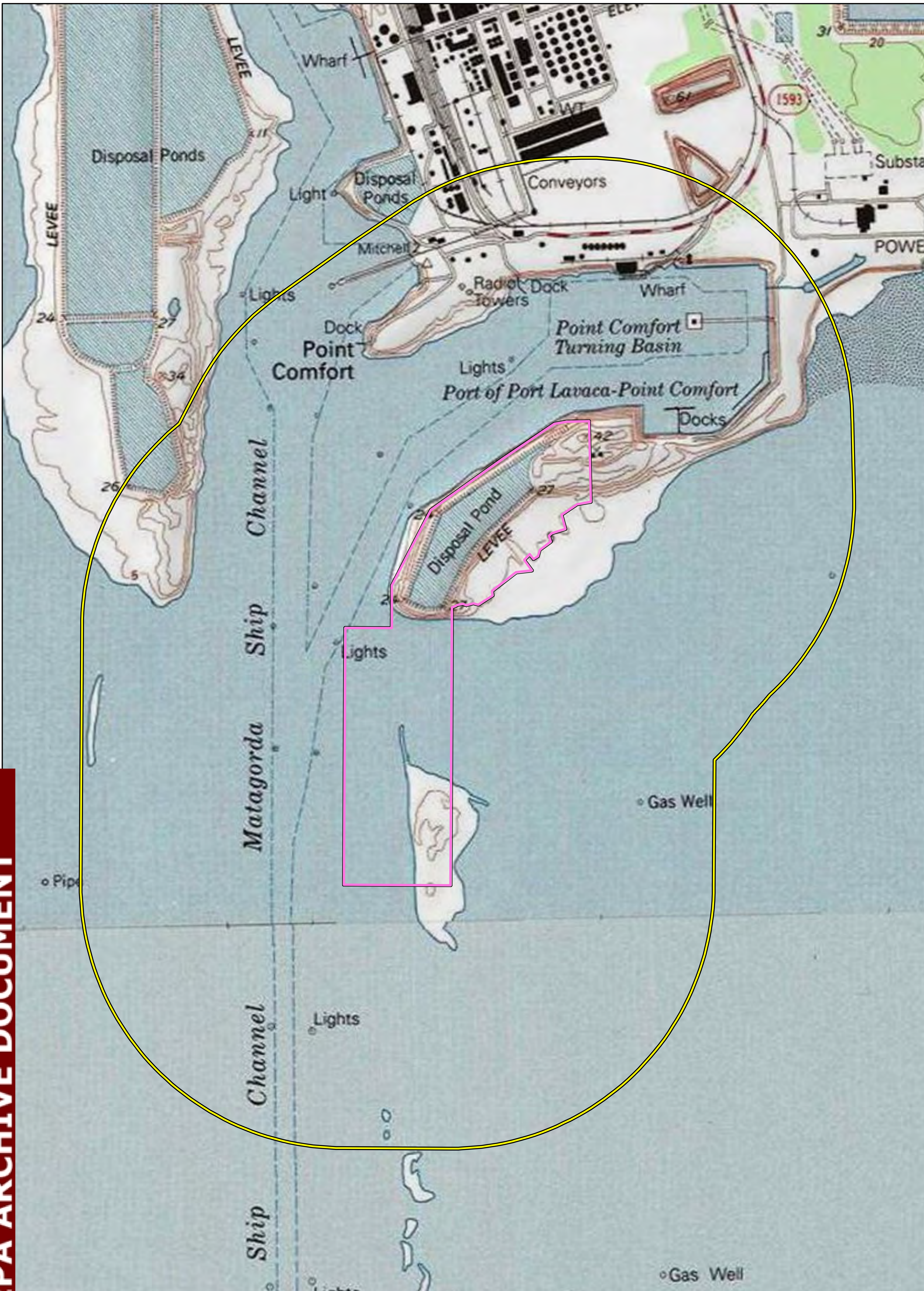
An area map of the site region is shown in Figure 2-1. A plot plan for the proposed Project is presented in Figure 2-2 and a process flow diagram is shown in Figure 2-3.

2.2.1 Marine Facilities

The marine facilities will consist of the following:

- Two FLSOs;
- New berthing pockets adjacent to the existing Matagorda Ship Channel (MSC);
- A jetty system (consisting of two berths) adjacent to the berthing pockets; and
- Mooring structures

The emission units at the marine facilities are described in detail in the following section. All marine facility emission units are located on the FLSOs so the following description only addresses that portion of the marine facilities.



Terminal Boundary

Terminal Boundary Buffer (3000ft)

Lavaca Bay LNG Project

Calhoun and Jackson Counties, Texas

Figure 2-1
Area Map

N

0 500 1,000 2,000 3,000

Feet

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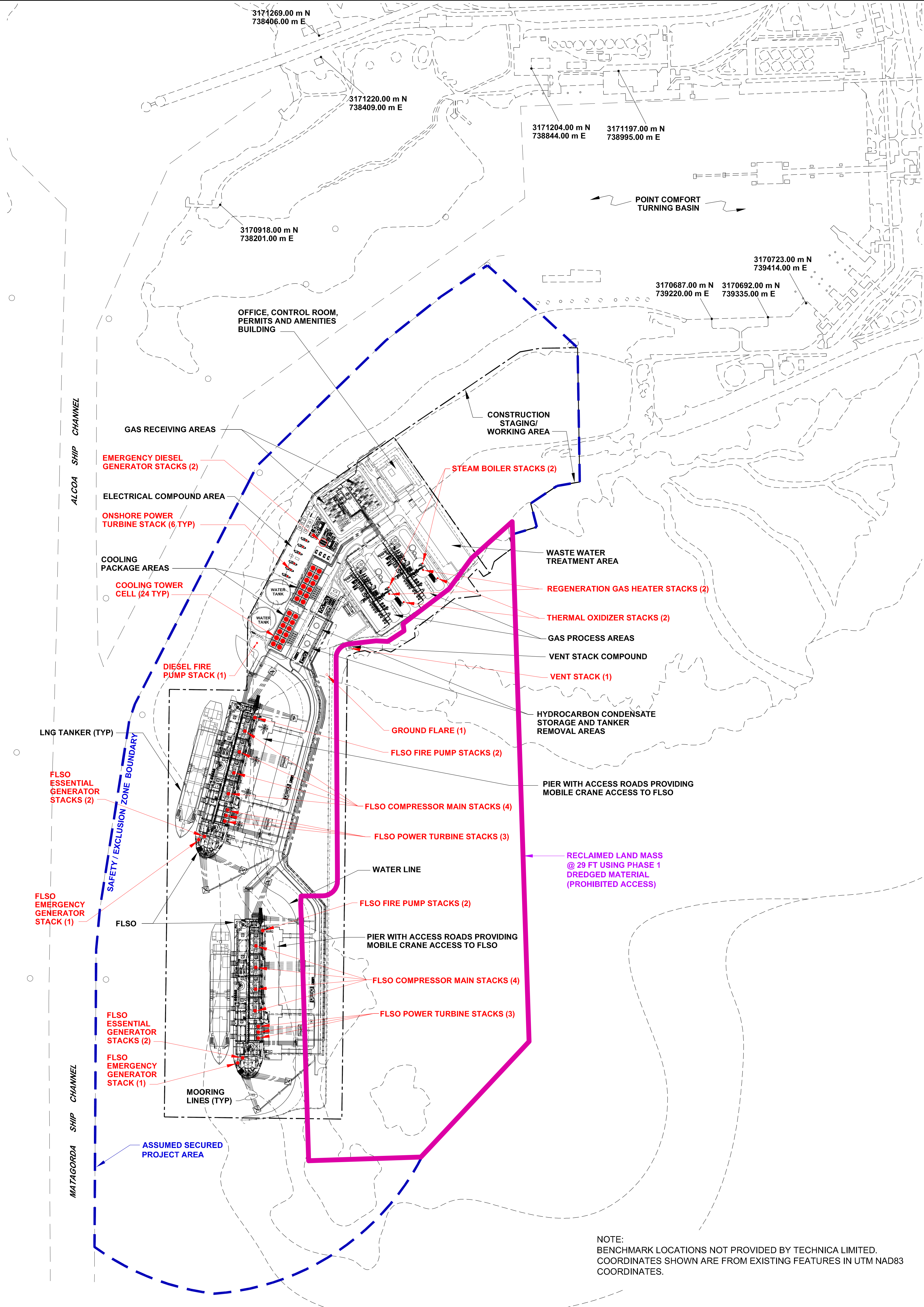


Source: Adapted from drawing "Lavaca Bay LNG FLSO Overall General Arrangement, Phases 1 & 2", dated 01/23/13 from Technica Limited.

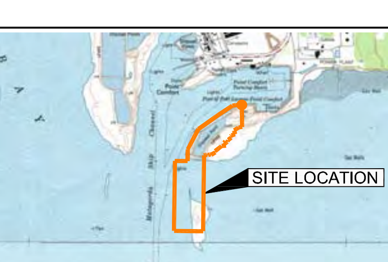
Fence Line
Existing Contour
Existing Bouy
Assumed Secured Project Area / Safety / Exclusion Zone Boundary
Reclaimed Land Mass @ 29 ft

Lavaca Bay LNG Project
Calhoun and Jackson Counties, Texas

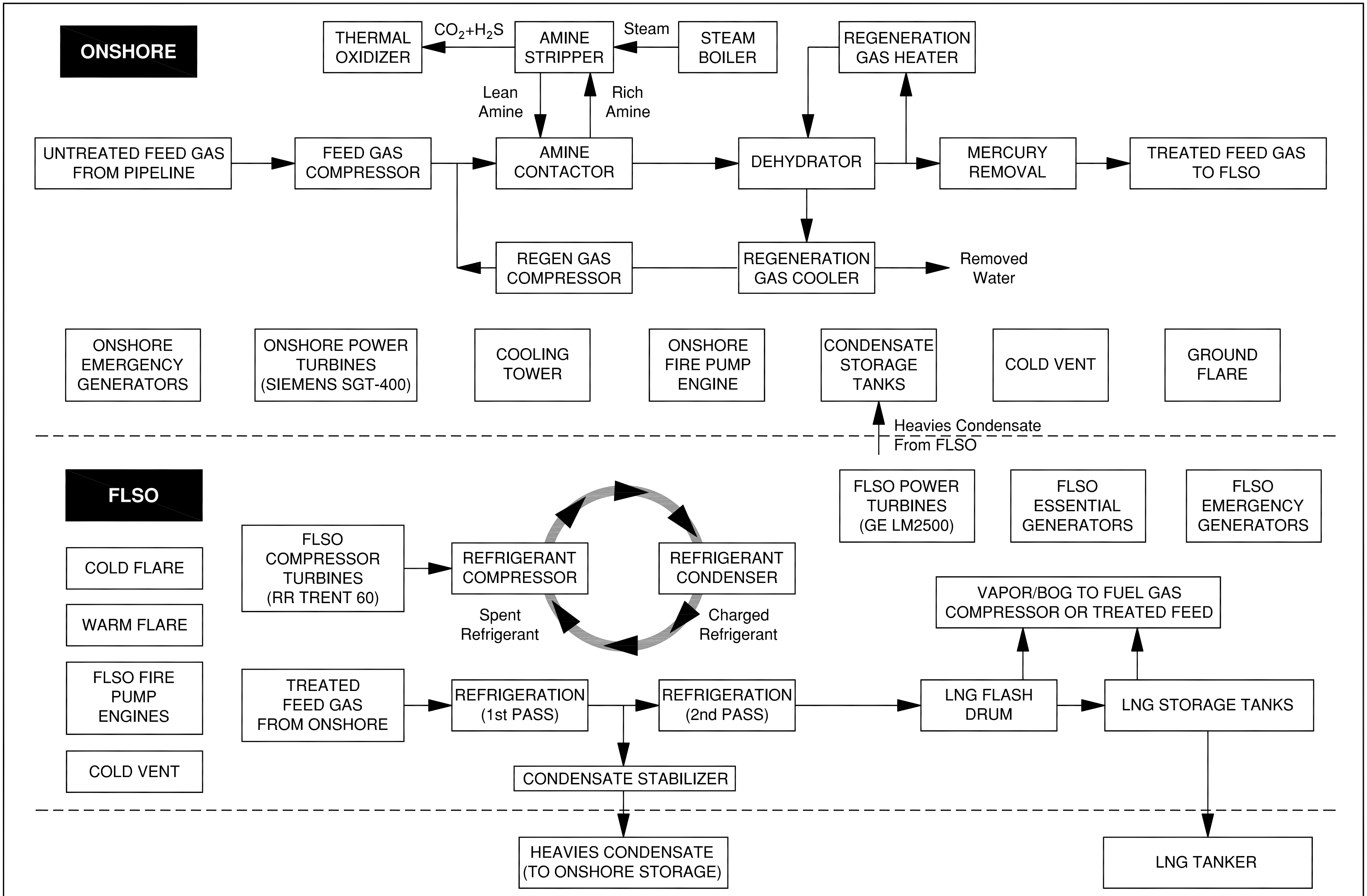
Figure 2-2
Plot Plan

0 600 1200
SCALE IN FEET

N



P:\EXCELERATE\LAVACA BAY FLOATING LIQUEFACTION\21-CAD\4620-2000_PROJ_LAYOUT_PLOT PLAN-REV_A.DWG PLOT/UPDATE: Mar 18 2014 13:08:14



Lavaca Bay LNG Project

Calhoun and Jackson Counties, Texas

Figure 2-3

Process Flow Diagram

P:\EXCELERATE\LAVACA BAY FLOATING LIQUEFACTION\21-CAD\4620-2000_LAVACA_PFD_REV A.DWG PLOT/UPDATE: May 1 2014 11:37:59

FLSOs

The FLSOs will have an overall length of approximately 1,100 feet (338 meters), a breadth (moulded) of approximately 203 feet (62 meters), a depth (moulded) of approximately 110 feet (33.4 meters), and a designed draft of approximately 49 feet (15 meters). Each FLSO's deadweight will be approximately 171,000 tons and the full load displacement will be 282,000 tons.

The FLSOs will be double-hulled. Within the hull of each FLSO, 10 LNG storage tanks with a liquid containment system designed by Gaztransport & Technigaz SA (GTT), referred to as the Mark III membrane containment system will be installed. The storage tanks will be laid out five tanks long by two tanks wide, with a nominal capacity of 25,100 m^3 each, making a total storage per FLSO of 251,000 m^3.

A series of modularized Process and Utility components will be located on each FLSO. Liquefaction will be provided on each FLSO using four PRICO system trains, each with a nominal capacity of one MTPA,[3] developed by Black & Veatch. Centrifugal refrigerator compressors will be powered by four Rolls-Royce Trent 60 Wet Low Emissions (WLE), or a similar model, aeroderivative mechanical drive gas turbines, forming a self-contained LNG production and storage facility. LNG-related equipment for managing boil-off and gas freeing liquid tanks will also be contained on the FLSOs.

The FLSOs will not be self-propelled and will only be capable of moving with the assistance of tugs. The FLSOs will be permanently moored to the shore utilizing the required number of mooring lines that are attached to each of the six "deadmen" located onshore. This will allow the FLSOs to remain in their berth pockets for the life of the Project regardless of weather conditions. The FLSOs will be capable of being relocated after the life of the Project and include all equipment necessary for operation in undeveloped locations.

Electrical power for FLSO operations will be provided onboard by three General Electric LM2500+G4, or a similar model, aeroderivative gas turbine generator (GTG) packages. The FLSO's electrical system will be capable of supplying all FLSO-based processes, utilities, marine (onboard) habitability, and safety systems to enable the liquefaction process to be carried out. An accommodation module, capable of housing up to 100 personnel, will be included onboard. Once emplaced in the Port, the self-sufficiency of the FLSOs will enable the FLSOs to remain at the berth pockets for the duration anticipated.

The FLSOs are being specifically designed with the ability to fit into a standard shipyard slot and will be constructed by Samsung Heavy Industries in the Republic of South Korea (South Korea). The FLSO will undergo extensive testing in the shipyard with final commissioning activities completed on-site. A summary of the main components on each FLSO is below.

Tank Pumps

Each FLSO will have three types of tank pumps; LNG cargo pumps, LNG spray/stripping pumps, and emergency LNG pumps. For each FLSO, there will be a total of 20 LNG cargo pumps of the centrifugal submerged type driven by integral electric motors. There will be 10 spray/stripping pumps and they will also be of the centrifugal submerged type driven by integral electric motors.

The LNG Cargo pumps will be used to:

- Transfer cargo to vessels receiving LNG from the facility;

[3] Under ideal atmospheric conditions and 100 percent availability, a PRICO system train can exceed one MTPA and produce up to 1.25 MTPA.

- Transfer cargo between the tanks on the FLSO.

The LNG spray/stripping pumps will be used to:

- Feed LNG to LNG vaporizer to produce warm gas for purging inert gas from the storage tanks.
- Spray LNG in the LNG storage tank for cooling down after warm gas purge is completed;
- Maintain temperature of an empty LNG storage tank or cool down after natural warming; and
- Strip the LNG storage tanks

There will be three sets of emergency LNG pumps stored in readiness for use. They will be capable of being handled through the top of the LNG storage tank without opening the tanks. These pumps will be electric motor driven.

High Duty Compressors

The high duty compressors will be centrifugal type, electric motor driven high duty compressors. There will be two sets of compressors (one in operation and one on stand-by) installed in the cargo machinery room of each FLSO. These will be used to:

- Transfer generated vapor to the LNGC during gas trial when loading LNG; and
- Re-circulate hot LNG vapor to warm-up the storage tanks on the FLSO during gas freeing operations

Boil-Off Gas Compressors

For each FLSO, there are three high pressure electrically driven boil-off gas centrifugal compressors supplying high pressure fuel gas for refrigerator compressor gas turbines and three medium pressure screw compressors supplying medium pressure fuel for power generation GTGs.

Refrigerator Compressor Turbines

The liquefaction process will consist of four refrigerator compressors on each FLSO driven by four Rolls-Royce Trent 60 WLE, or a similar model, gas turbines.

Instrument Air Packages

Instrument air (control air) is provided on each FLSO by two electrically driven screw-type compressors. These control air compressors will be fresh water-cooled and located in the forward machinery space. Control air from the compressors is led to two control air reservoirs. Three control air dryers (adsorption type) are provided for removing the moisture in the control air system.

Plant Air

Plant air (general air) is provided on each FLSO by an electrically driven screw-type compressor. This general service air compressor will be fresh water-cooled and supply air to one general service air reservoir forward and one aft. A shut-off valve is provided at each air distribution group in the forward, aft and cargo machinery spaces. Hose connection valves are fitted for general service usage in all spaces.

Nitrogen Packages

On board each FLSO, two membrane type nitrogen generation packages will be used to purge pipelines and equipment during preparation, for sealing compressors, and for using as refrigerant.

Power Generation Turbines and Supply Equipment

The primary source for power generation for each of the FLSOs will be three General Electric LM2500+G4, or a similar model, aeroderivative natural gas fueled GTG packages. Two of the three GTGs will be in continual use with the third GTG on standby / reserve mode. However, the third GTG will be brought into service when offloading LNG cargo. Essential generator sets will consist of two 5.5 megawatt (MW) generator packages. The service function of these generators is for start-up, black start scenarios, and in the event of a GTG service failure while offloading operations are underway. Emergency power generation will be provided by one diesel turbo-charged 1.3 MW generator package. The sole purpose of the generator will be to provide emergency lighting and battery charging capabilities in a power failure scenario in which no power can be provided by the GTG's or the essential generators.

Flares and Vents

Each FLSO will include an elevated flare tower containing two high-pressure process flares, and one low-pressure tank relief and maintenance flare. The two high-pressure process flares include a cold flare and a warm flare, which will handle gases purged from the FLSO’s cryogenic and non-cryogenic piping systems, respectively. The two high-pressure flares will operate with a continuous pilot flame to burn routine flows of purged gas, and are also designed to accept emergency releases of gas. The low-pressure tank relief and maintenance flare will burn gases produced during “gas freeing” of the LNG storage tanks for periodic inspections, and during infrequent “gas-in” or “cooldown” operations for any LNGCs that arrive at the terminal with only inert gas or warm methane vapor in their cargo tanks. The low-pressure flare will also receive emergency releases of gas from the LNG storage tank relief valves. Each FLSO will also include a low-pressure tank maintenance cold vent, which will receive any gases from the LNG storage tanks or LNGCs that do not have a sufficient heating value to be flared.

Firewater Systems

Each of the FLSOs will have two electric driven and two diesel engine driven fire pumps. Firewater will be supplied from the surrounding bay through sea chests on each FLSO.

Other Process or Auxiliary Equipment and Structures

- Inert Gas
- Distilled Water
- Potable Water
- Hot Oil
- Oily water/effluent treatment
- Closed/open drains

2.2.2 Onshore Facilities

The onshore facilities will be required for treatment of natural gas from the pipeline prior to transfer to both of the FLSOs. Construction and operational support infrastructure will also be included with the onshore facilities. Specifically, the onshore facilities will include:

- Construction staging/worker area;
- Feed gas metering;
- Inlet bulk separation;

- Feed gas pre-treatment;
- Condensate storage;
- Power generation (primary and essential/emergency);
- Onshore utilities;
- Vent/flare facilities;
- Oily water/effluent treatment plant; and
- Support buildings, including offices, control room, warehouse, and shop

Pipeline quality gas will be piped into inlet facilities located onshore for metering, compression and processing. The processed, liquefiable gas stream will be piped aboard the FLSOs via “Chiksan” style loading arms directly into feed gas streams for liquefaction located on the FLSO.

A description of each component of the onshore facilities required for both of the FLSOs is included below.

Construction Staging/Worker Area

ELO Port Lavaca has available the 25 acres of land to the north of the proposed oily water/effluent treatment plant and operation support buildings for use during construction. The area will be used primarily for construction staging and ELO Port Lavaca will maintain use of the 25-acre area throughout the life of the Project. Because this area is located within the fenceline for the onshore facilities, it will be considered permanent.

Inlet Bulk Separation

In the event that pipeline pigging does result in liquid slugs entering the LNG terminal, a bulk inlet separator will allow the majority of this liquid to be removed and sent to the closed drains system. Inlet bulk separation will reduce the loads on the compressor suction vessels, and help minimize the potential for free liquid carryover to downstream equipment.

Feed Gas Metering

A metering system will be installed at the outlet of the gas treatment plant prior to the inlet of each high pressure gas arm before the gas is transferred to the FLSO. The metering system will consist of dual, Fiscal Standard, and Ultrasonic Flow meters configured as duty/stand-by with a single chromatograph analyzer monitoring the gas quality.

Feed Gas Pre-Treatment

Amine System

An amine system will be located onshore to remove carbon dioxide and hydrogen sulfide from the feed gas. The amine system will include a thermal oxidizer to incinerate reduced sulfurs.

Dehydration

Although the pipeline quality feed gas will have already been dehydrated to low levels, there may be residual water content unsuitable for processing in a liquefaction process. To effectively reduce the water content to zero, further dehydration will be carried out downstream of the amine system. This dehydration system will utilize molecular sieve adsorbent to remove water and will be regenerated using treated feed gas. The saturated regeneration gas will be cooled to condense the water component, separated, re-compressed and recycled back to the amine unit inlet. The dehydrated feed gas will pass through a mercury removal bed and then be routed to the FLSO via process flow meters for heavies removal and liquefaction. The mercury removal bed is replaced approximately every 5 years upon saturation by a licensed contractor.

Condensate Storage

Hydrocarbon condensate will be produced in the FLSOs and stored in two hydrocarbon storage tanks within the onshore facilities. At regular intervals the condensate from the storage tanks will be offloaded to road tankers to control the inventory in the storage tank.

Onshore Utilities

Cooling Water System

A cooling water system will be provided within the onshore facilities, composed of a cooling tower system, circulation pumps, water makeup, and chemical addition. The onshore facilities will utilize a closed-loop system. The cooling tower will be designed to reject heat gained from both onshore and FLSO sources. The source of the cooling water will be from the utility water storage tanks located within the onshore facilities. These tanks, each with a capacity of approximately 7.5 million gallons, will be supplied from municipal sources.

Instrument/Plant Air and Nitrogen

An instrument air package will be installed to produce the instrument air to meet the onshore facilities' instrument air requirement. The instrument air package consists of two compressors, where one is in service and the other is standby. A nitrogen generation package will also be installed to meet the onshore facilities' nitrogen requirement.

Power Generation

Electrical power to the onshore facilities will be supplied via a combination of gas and steam turbine generating sets. Seven Siemens SGT-400, or a similar model, natural gas fired combined cycle electric generation turbines and two steam turbines will be installed but no more than six will operate at any time.

The gas turbines will be fueled by natural gas only via a tie-in to the incoming feed gas and will operate in 6 + 1 duty/standby mode. The steam turbines will be running continuously using heat recovery steam generators installed within the exhaust ducting of each gas turbine.

Emergency power supplies for the onshore facilities will be provided by emergency diesel generators with an electric starter. These generators will also provide power for a "black-start"[4] of the facility.

The main high voltage transformer and switchgear will be co-located with the generators within the electrical compound, with low voltage switchgear in local equipment rooms located throughout the facility as required.

As only low voltage power will be required for the remote metering stations, this will be sourced from local grid connections.

[4] A black-start is the procedure to recover from a total or partial shutdown which has caused an extensive loss of supplies. This entails isolated power stations being started individually and gradually being reconnected to each other in order to form an interconnected system again.

Cold Vent and Ground Flare

In order to facilitate the safe de-inventory of hydrocarbon gas when required, both a cold vent and a ground flare will be installed. The purpose of the cold vent will be to allow the rapid depressurization of the onshore facilities in an emergency scenario. The ground flare system will be used when controlled depressurization is required, e.g., for maintenance. This operation can take place over a prolonged period of time, with the flare used to minimize the atmospheric emission of flammable gas.

Firewater

A fire water system will be installed to provide adequate fire water to the various areas of the LNG terminal facilities to allow fire-fighting activities to take place and to prevent escalation of an existing incident. The fire water supply will be from the utility water storage tank which in turn is supplied from municipal sources. The storage tanks each have a capacity of approximately 7.5 million gallons. The utility water storage tank level will be monitored and in case of a low storage tank level, a standby diesel powered sea water pump will be started to feed the fire water main ring.

Oily Water/ Effluent Treatment

To eliminate any hazardous liquid emissions to the environment, the LNG terminal will feature an oily water/effluent treatment plant. This system will treat contaminated water from both the onshore facilities and the FLSO. The exact treatment flow rates and capacity will be determined during detailed design. The system will consist of three main components:

- Oily water treatment package;
- Cooling water blow down treatment package; and
- Effluent water treatment package

The oily water system collects and treats hydrocarbon-contaminated liquids from the onshore facilities closed drains system and spill collection areas, as well as bilge water and closed drains from the FLSOs. The package will allow bulk separation of hydrocarbon liquids, water and solids. Hydrocarbon liquids and solids will be removed by truck for off-site disposal. The produced water will be sent to the cooling water blow down treatment package.

The cooling water blow down treatment package neutralizes the dosing chemicals added to the cooling water. Blow down water from the cooling towers is treated along with produced water from the oily water/effluent treatment packages. Once treated, the water can be disposed of via road tanker, direct to sea (if within local discharge specifications), reused within the cooling water loop or recycled to the oily water treatment package if specifications are not met.

The effluent water treatment package receives effluent water from the onshore facilities and the FLSOs. The package performs preliminary treatment prior to further processing in the cooling tower blow down treatment plant.

Support Buildings

Operation support buildings will include a control room located in the main building that will include office space, a warehouse, and a shop to allow for repairs and maintenance.

3.0 GHG EMISSIONS

This section presents long-term potential emissions of GHGs from the proposed Project. Annual potential GHG emissions for the marine facilities are addressed in Section 3.1. Annual potential GHG emissions for the onshore facilities are addressed in Section 3.2. Site-wide annual potential emissions are presented in Section 3.3. The Emission Point Numbers (EPNs) proposed for each source in the PSD non-GHG permit application submitted to TCEQ on May 15, 2014 are listed in their respective subsections below. In general, emissions are tabulated on an annual basis per EPN. However, in some cases emissions are proposed by ELO Port Lavaca to be limited to less than full load operation throughout the year so for these cases, emissions are also tabulated on an annual basis for the combined group of similar EPNs to reflect these limitations. See Section 5 of this application for the Best Available Control Technology (BACT) analysis for GHG emissions from each proposed emission source. Appendix B of this application contains detailed GHG emission calculations. Appendix C of this application contains vendor information and equipment performance data.

GHG, as an air pollutant subject to PSD review, is defined in the Code of Federal Regulations (CFR) at 40 CFR 51.166(b)(48), as the aggregate group of six greenhouse gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).[5] Potential emissions of GHG are measured in units of CO_2 carbon dioxide equivalent (CO_2e), which are determined by first multiplying the mass emissions for each of the six greenhouse gases by its associated global warming potential (GWP), which is listed in Table A-1 of 40 CFR 98, and then by summing the resulting values.

Table 3-1 lists the relevant GWPs that are in effect as of January 1, 2014.[6]

Table 3-1
Selected GWPs from Table A-1 of 40 CFR 98

Compound	CAS Number	Chemical Formula	Global Warming Potential (100-Year Time Horizon)
Carbon dioxide	124-38-9	CO_2	1
Methane	74-82-8	CH_4	25
Nitrous oxide	10024-97-2	N_2O	298
Sulfur hexafluoride	2551-62-4	SF_6	22,800

The proposed Project will only have emissions of CO_2, CH_4, and N_2O, so the GWPs for HFCs and PFCs, which include multiple individual compounds each with a different GWP, are not listed here. Sulfur hexafluoride is used chiefly as an insulating gas inside electrical switchgear produced by some manufacturers. No components containing SF_6 will be used by the proposed Project.

3.1 Marine Facilities

The marine facilities will include two FLSOs. The FLSOs liquefy a treated gas stream, store the LNG, then off-load the LNG to an LNGC. This section describes the emission units and potential emissions associated with the FLSOs.

[5] U.S. Government Printing Office (GPO), Electronic Code of Federal Regulations (e-CFR), last modified May 22, 2014, http://www.ecfr.gov.
[6] EPA updated the GWPs for certain compounds, including CH_4 and N_2O, effective January 1, 2014. (See 78 FR 71903, Nov. 29, 2013.)

3.1.1 Refrigerator Compressor Turbines Normal Operations

EPNs: NFLSOCT1 through NFLSOCT4 (North FLSO)
SFLSOCT1 through SFLSOCT4 (South FLSO)

Each FLSO will have four aeroderivative natural gas fired simple cycle refrigerator compressor turbines, which will be Rolls-Royce Trent 60 WLE, or a similar model. Each turbine will be rated at approximately 59 MW of shaft power output, each with a maximum heat input rate of approximately 534.7 million British thermal units (MMBtu) per hour[7] at 15 degrees Celsius (°C) (59 degrees Fahrenheit [°F]) ambient temperature. These turbines will drive the compressors for the liquefaction refrigeration system. Table 3-2 shows potential annual GHG emissions for the FLSO refrigerator compressor turbines. For all GHG pollutants, potential annual emissions are based on vendor information for steady-state full load operation, using the 100% load case at 15 °C ambient temperature. Each turbine may operate for up to 8,760 hours per year at full load. Emissions of CO_2 and N_2O are calculated using the emission factors for general stationary fuel combustion sources in Subpart C of 40 CFR 98, which for natural gas combustion are: 53.06 kilogram (kg) CO_2/MMBtu, and 0.0001 kg N_2O/MMBtu. CH_4 emissions are based on the vendor-estimated concentration for unburned hydrocarbons (UHC) minus the vendor-estimated concentration for VOC, both provided as methane equivalent concentrations in parts per million by volume on a dry basis (ppmvd) at 15 percent oxygen (O_2). CO_2e emission rates use GWPs of 25 for CH_4, and 298 for N_2O, from Table A-1 of 40 CFR 98.

Table 3-2
FLSO Refrigerator Compressor Turbines –Potential Annual GHG Emissions

Pollutant	Tons per Year (tpy) (per turbine)
CO_2	273,930
CH_4	25.8
N_2O	0.52
CO_2e	274,729

3.1.2 Refrigerator Compressor Turbine Startup/Shutdown

EPNs: NFLSOCT1 through NFLSOCT4 (North FLSO)
SFLSOCT1 through SFLSOCT4 (South FLSO)

The FLSO refrigerator compressor turbines will be shut down periodically for scheduled inspections and maintenance. According to a typical Rolls-Royce maintenance schedule, each turbine must be shut down once per year for inspections and maintenance, with each outage lasting approximately 4 days. Typical mass emission totals per startup and shutdown event have been obtained from another Trent 60 project for UHC (assumed to be mainly methane) and VOC (assumed to be the non-methane component of UHC), and have been used to estimate the additional potential GHG emissions resulting from one startup/shutdown cycle per compressor turbine per year.

Table 3-3 presents increased total GHG emissions due to startup and shutdown. Even though annual operating hours will be less than 8,760 due to the 4-day maintenance outage, the increased total emissions shown below conservatively assume that each compressor turbine operates without interruption. Startup and shutdown emissions increase the annual facility-wide totals for CH_4 and CO_2e by a very small

[7] Unless otherwise stated, all heat rates and heating values are presented in terms of higher heating value (HHV).

amount. CO_2 and N_2O emission totals do not increase because the worst-case 1-hour emissions for these pollutants are lower during startup and shutdown than during full load operation. See Appendix B of this application for detailed emission calculations.

Table 3-3
FLSO Refrigerator Compressor Turbines – Additional GHG Emissions from Startup/Shutdown

Pollutant	Increased Annual tpy (per SUSD Cycle)
CO_2	N/A
CH_4	0.099
N_2O	N/A
CO_2e	2.5

3.1.3 Power Generation Turbines

EPNs: NFLSOPT1 through NFLSOPT3 (North FLSO)
SFLSOPT1 through SFLSOPT3 (South FLSO)

Each FLSO will have three aeroderivative natural gas fired electric generation turbines, which will be General Electric LM2500+G4, or a similar model. Each turbine will be rated at approximately 32.9 MW of shaft power output at an ambient temperature of 24 °C (75 °F), with a maximum heat input rate of 372.7 million British thermal units per hour (MMBtu/hr) at an ambient temperature of 4.4 °C (40 °F). These turbines will generate electricity to power all the electric-driven equipment on each FLSO. Each turbine will also have an associated waste heat recovery unit (WHRU), which uses excess heat from the exhaust gas to warm a circulating mineral oil bath. This heated oil is used by various processes onboard the FLSO, including the fuel gas heater and the LNG vaporizer. Emission rates are based on vendor information for steady-state full load operation. Each turbine may operate for up to 8,760 hours per year at full load. Annual potential emissions assume operation equivalent to 8,760 hours per year at full load for two of the three power turbines on each FLSO, and 1,036 hours per year at full load for the third power turbine on each FLSO. It is anticipated that all three turbines will normally operate only during cargo transfer to an LNGC, but any combination of turbines may be operated at any time.

Table 3-4 shows potential annual GHG emissions for a single FLSO power generation turbine, and for the combined operation of all six FLSO power generation turbines (three per FLSO). For all GHG pollutants, potential annual emissions are based on the 100% load case at 24 °C ambient temperature, with a per-turbine heat input rate of 337.9 MMBtu/hr. Emissions of CO_2 and N_2O are calculated using the emission factors for general stationary fuel combustion sources in Subpart C of 40 CFR 98, which for natural gas combustion are: 53.06 kg CO_2/MMBtu, and 0.0001 kg N_2O/MMBtu. CH_4 emissions are calculated by subtracting the VOC emission rate (based on the EPA *AP-42* emission factor for gas-fired turbines[8]) from the UHC emission rate (based on the vendor-estimated UHC concentration, provided as a methane equivalent concentration in ppmvd at 15 percent O_2). CO_2e emission rates use GWPs of 25 for CH_4, and 298 for N_2O, from Table A-1 of 40 CFR 98.

[8] U.S. Environmental Protection Agency (EPA), *AP-42, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources*, 5th ed. (Research Triangle Park, NC: EPA Office of Air Quality Planning and Standards, Office of Air and Radiation, January 1995), http://www.epa.gov/ttnchie1/ap42/index.html.

Table 3-4
FLSO Power Generation Turbines – Potential Annual GHG Emissions

Pollutant	tpy (per turbine)	tpy (all 6 turbines)
CO_2	173,124	733,445
CH_4	10.2	43.1
N_2O	0.33	1.4
CO_2e	173,476	734,935

3.1.4 Essential Generators

EPNs: NESGEN1 and NESGEN2 (North FLSO)
SESGEN1 and SESGEN2 (South FLSO)

Each FLSO will have two diesel oil fired "essential generators," which will be MAN 12V32/40 engines or a similar model. Each engine will be rated at approximately 5,760 kilowatt (kW) of shaft power output, with an electric generator output of approximately 5,472 kW, and with a maximum heat input rate of approximately 47.1 MMBtu/hr. These engines will operate to generate electricity during initial startup of the FLSO equipment, to supplement the output of the power turbines during cargo transfer and at other times, to supply power during periods of maintenance on a power turbine, during emergencies, and for maintenance and testing. The final engine model selected will be equipped with controls sufficient to meet the applicable standards under 40 CFR 60 Subpart IIII, which for engines of this size and purpose, are the EPA Tier 4 standards for non-road generating sets, as listed in 40 CFR 1039. Fuel oil sulfur content will be limited to no more than 0.0015 percent by weight. Annual potential GHG emissions assume that each essential generator will operate for up to 720 hours per year at full load. Table 3-5 shows potential annual GHG emissions for the FLSO essential generators. Emissions of CO_2, CH_4, and N_2O are calculated using the emission factors for general stationary fuel combustion sources in Subpart C of 40 CFR 98, which for combustion of distillate fuel oil No. 2 are: 73.96 kg CO_2/MMBtu, 0.003 kg CH_4/MMBtu, and 0.0006 kg N_2O/MMBtu. CO_2e emission rates use GWPs of 25 for CH_4, and 298 for N_2O, from Table A-1 of 40 CFR 98.

Table 3-5
FLSO Essential Generators – Potential Annual GHG Emissions

Pollutant	tpy (per engine)
CO_2	2,767
CH_4	0.11
N_2O	0.022
CO_2e	2,776

3.1.5 Emergency Diesel Generator

EPNs: NFLSOEGN (North FLSO)
SFLSOEGN (South FLSO)

Each FLSO will have one diesel oil fired emergency generator, which will be a Cummins KTA50-DM1 engine, or a similar model. This engine will be rated at approximately 1,290 kW of shaft power output, with a maximum heat input rate of approximately 11.5 MMBtu/hr. The emergency generator will operate to generate electricity to start up the essential generators, during emergencies, and for maintenance and testing. The emergency generator will be subject to the applicable standards under 40 CFR 60 Subpart IIII, which for an engine of this size and purpose, are the EPA Tier 2 standards for engines larger than 560 kW, as listed in 40 CFR 89.112. The Cummins KTA50-DM1 engine currently selected does not achieve the required Tier 2 emission limits; however, the final engine model selected will be compliant so these standards have been assumed for potential emissions. Fuel oil sulfur content will be limited to no more than 0.0015 percent by weight. Annual potential emissions assume that each emergency generator will operate for up to 52 hours per year at full load. Table 3-6 shows potential annual GHG emissions for the FLSO emergency generator. Emissions of CO_2, CH_4, and N_2O are calculated using the emission factors for general stationary fuel combustion sources in Subpart C of 40 CFR 98, which for combustion of distillate fuel oil No. 2 are: 73.96 kg CO_2/MMBtu, 0.003 kg CH_4/MMBtu, and 0.0006 kg N_2O/MMBtu. CO_2e emission rates use GWPs of 25 for CH_4, and 298 for N_2O, from Table A-1 of 40 CFR 98.

Table 3-6
FLSO Emergency Generator – Potential Annual GHG Emissions

Pollutant	tpy (per engine)
CO_2	49
CH_4	2.0E-03
N_2O	4.0E-04
CO_2e	49

3.1.6 Fire Pump Engines

EPNs: NFLSOFP1 and NFLSOFP2 (North FLSO)
SFLSOFP1 and SFLSOFP2 (South FLSO)

Each FLSO will have two diesel oil fire pump engines, which will be Cummins QSK60-DM engines, or a similar model. Each engine will be rated at approximately 1,900 kW of shaft power output, with a maximum heat input rate of approximately 17.6 MMBtu/hr. The fire pump engines will operate during emergencies, and for maintenance and testing. The engines will be subject to the emission standards for fire pump engines in Table 4 of 40 CFR 60, Subpart IIII. The Cummins QSK60-DM model currently selected does not achieve the required emission limits; however, the final engine model selected will be compliant. Fuel oil sulfur content will be limited to no more than 0.0015 percent by weight. Annual potential GHG emissions assume that each fire pump engine will operate for up to 52 hours per year at full load. Table 3-7 shows potential annual GHG emissions for the FLSO fire pump engines. Emissions of CO_2, CH_4, and N_2O are calculated using the emission factors for general stationary fuel combustion sources in Subpart C of 40 CFR 98, which for combustion of distillate fuel oil No. 2 are: 73.96 kg CO_2/MMBtu, 0.003 kg CH_4/MMBtu, and 0.0006 kg N_2O/MMBtu. CO_2e emission rates use GWPs of 25 for CH_4, and 298 for N_2O, from Table A-1 of 40 CFR 98.

Table 3-7
FLSO Fire Pump Engines – Potential Annual GHG Emissions

Pollutant	tpy (per engine)
CO_2	75
CH_4	3.0E-03
N_2O	6.1E-04
CO_2e	75

3.1.7 Cold Flare

EPNs: NFLSOCF (North FLSO)
SFLSOCF (South FLSO)

Each FLSO will be equipped with one cold flare, which will flare off any gases vented from relief valves in the cryogenic portions of the liquefaction or LNG storage systems. The cold flare is designed for a maximum emergency gas relief rate of 142,402 kg/hour. The cold flare will operate with a continuous pilot flame for 8,760 hours per year to burn gases purged from the FLSO's cryogenic piping systems. The cold flare will also operate during emergencies, which are anticipated to occur very infrequently, if ever. Table 3-8 shows estimated annual GHG emissions for the FLSO cold flares during continuous purging and pilot burner operation. Emissions of CO_2 and N_2O are calculated using the emission factors for general stationary fuel combustion sources in Subpart C of 40 CFR 98, which for natural gas combustion are: 53.06 kg CO_2/MMBtu, and 0.0001 kg N_2O/MMBtu. In accordance with TCEQ BACT guidance for flares, CH_4 emissions assume 99 percent destruction of all hydrocarbons in the flared gas that contain three or fewer carbons (CH_4, C_2H_6, and C_3H_8), which are all conservatively treated as methane for the purpose of the emission calculation.[9]

Table 3-8
FLSO Cold Flare – Potential Annual GHG Emissions

Pollutant	tpy (per flare)
CO_2	5,598
CH_4	19.6
N_2O	0.011
CO_2e	6,092

3.1.8 Warm Flare

EPNs: NFLSOWF (North FLSO)
SFLSOWF (South FLSO)

Each FLSO will be equipped with one warm flare, which will flare off any gases vented from relief valves in the non-cryogenic portions of the liquefaction or LNG storage systems. The warm flare is designed for a maximum emergency gas relief rate of 101,894 kg/hour. The warm flare will operate with a continuous pilot flame for 8,760 hours per year to burn gases purged from the FLSO's non-cryogenic piping systems. The warm flare will also operate during emergencies, which are anticipated to occur very infrequently if ever. Table 3-9 shows estimated annual GHG emissions for the FLSO warm flares during continuous purging and pilot burner operation. Emissions of CO_2 and N_2O are calculated using the emission factors for general stationary fuel combustion sources in Subpart C of 40 CFR 98, which for natural gas combustion are: 53.06 kg CO_2/MMBtu, and 0.0001 kg N_2O/MMBtu. In accordance with TCEQ BACT guidance for flares, CH_4 emissions assume 99 percent destruction of all hydrocarbons in the flared gas that contain three or fewer carbons (CH_4, C_2H_6, and C_3H_8), which are all conservatively treated as methane for the purpose of the emission calculation.

[9] Texas Commission on Environmental Quality (TCEQ), "Current Best Available Control Technology (BACT) Requirements: Flares and Vapor Combustors" (August 2011), https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_flares.pdf.

Table 3-9
FLSO Warm Flare – Potential Annual GHG Emissions

Pollutant	tpy (per flare)
CO_2	5,581
CH_4	19.5
N_2O	0.011
CO_2e	6,072

3.1.9 FLSO LNG Tank Inspections

EPNs: NFLSOTRMF and NFLSOTMV (North FLSO)
SFLSOTRMF and SFLSOTMV (South FLSO)

(Note: Each FLSO will be equipped with one dedicated low-pressure tank relief and maintenance flare located on the flare tower alongside the high-pressure cold and warm flares, and one low-pressure tank maintenance cold vent. The emissions related to FLSO LNG tank inspections in Section 3.1.9, and LNGC gas-in and cooldown in Section 3.1.10, will occur at the tank relief and maintenance flare, and at the tank maintenance cold vent.)

In order to maintain compliance with American Bureau of Shipping classification rules for LNG storage facilities, each LNG storage tank on the FLSO must be physically inspected once every five years. Since each FLSO has 10 LNG storage tanks, two tanks on each FLSO will be inspected every year. The following steps are involved in preparing an empty LNG storage tank for inspection, and then preparing it to accept LNG again:

1) Warming Up: Residual liquid LNG in the empty tank is vaporized, and the secondary barrier is warmed to 5 °C. Cold LNG vapor in the empty tank is sent to the high duty compressor and then to the warm-up heater, after which it is returned to the bottom of the tank. Excess warm LNG vapor will be sent to the low-pressure tank relief and maintenance flare.

2) Gas Freeing: Warm LNG vapor is replaced by inert gas, which is introduced at the bottom of the tank until the hydrocarbon concentration inside the tank is reduced to 2 percent by volume. Displaced LNG vapor will be flared until the methane concentration drops below 5 percent by volume, at which point gases will be sent to the tank maintenance cold vent.

3) Aerating: Dry air is introduced at the top of the tank, pushing inert gas to the tank maintenance cold vent. This step will continue until the tank contains a safe, breathable atmosphere, with at least 20 percent O_2, and less than 0.2 percent CH_4, 0.5 percent CO_2, and 50 ppm CO, by volume.

4) Perform tank inspection.

5) Drying: Dry air is again introduced, this time at the bottom of the tank, to push out moist atmospheric air that has entered during the tank inspection period. This step will continue until the dew point in the tank drops below -20 °C. (No pollutant emissions are associated with step, as only air is sent to the tank maintenance cold vent.)

6) Inerting: Inert gas is introduced at the bottom of the tank, pushing dry air to the tank maintenance cold vent. This step will continue until the tank contains less than 2 percent O_2, and the dew point in the tank drops below -40 °C.

7) Gas-In: Warm LNG vapor is produced by the LNG vaporizer, and introduced at the top of the tank to push inert gas to the tank maintenance cold vent until the methane concentration reaches 5 percent by volume, at which point it will be sent to the tank relief and maintenance flare. The gas-in step will continue until the tank contains less than 1.0 percent CO_2 by volume.

8) Cooldown: Liquid LNG is sprayed through the header at the top of tank, where it evaporates and cools the tank walls and insulation. Cooldown will continue until an average tank temperature of -130 °C is achieved (excluding the top temperature sensor). Boil-off gas produced by this step may either be (a) sent to the fuel gas compressor for use by the FLSO combustion turbines; (b) sent to one or more of the other LNG storage tanks through a vapor return line; or (c) warmed to ambient temperature prior to being sent to the tank relief and maintenance flare. The amount of gas that must be flared will depend on the fuel demand and available headspace in the other tanks during the procedure. For worst-case potential emissions, it is assumed that all of the boil-off gas will be flared.

Each FLSO will be equipped with an inert gas generator (IGG) to produce the inert gas required in steps 2 and 6 of the LNG tank inspection process. The IGG will be an Aalborg "Smit Gas GIn 15.000- 0.25 BUFD", or a similar model, with a maximum rated heat input of approximately 62.5 MMBtu/hr, capable of generating 15,000 Nm^3/hour of inert gas at a temperature of 30 °C. The IGG will burn ultra low-sulfur diesel (ULSD) fuel oil to create a low-oxygen gas, which is then scrubbed with seawater and dried to remove all traces of moisture, resulting in a final product containing about 85 percent nitrogen, 14 percent CO_2, and no more than 0.5 percent O_2, with trace amounts of NO_x, CO, and SO_2. This gas can then be safely introduced into an LNG tank without risk of creating an explosive mixture. (For the purpose of GHG emission calculations, the inert gas is assumed to contain no CH_4 or N_2O.)

The IGG can also be used in dry air mode, which simply removes the moisture from ambient air, to provide the dry air required in steps 3 and 5 of the LNG tank inspection process.

The composition of the LNG vapor vented from the tank in step 1, and produced during steps 7 and 8, is assumed to be identical to that of "Net LNG to Storage," as provided by ELO Port Lavaca (see Appendix B of this application).

Durations, flow rates, and temperatures for the gases involved in each step have been estimated based on documents and guidance provided by Gaztransport & Technigaz SA (GTT). For each step, gas will be introduced at the proper flow rate and tank location (either top or bottom) to produce a "piston effect," which takes advantage of the different densities between gases to cause one to sit on top of the other, forming two layers. This eliminates mixing of the gases, except at the boundary between layers, thus minimizing the gas volume required to replace a tank's contents. For most steps, a replacement ratio of 1.7 is sufficient to replace the gas in one LNG storage tank (approximately 42,670 m^3 of replacement gas for a tank capacity of 25,100 m^3). For step 5 (drying), a replacement ratio of 1.9 is required due to the very similar densities of dry air and damp atmospheric air. Steps 1 and 8 (warming up and cooling down) are governed by the minimum time required for safe thermal expansion or contraction of the tank, rather than a specific volume of gas to be introduced. The following durations have been estimated for each step:

1) Warming Up: 44 hours to raise the tank temperature from -140 °C to 50 °C, during which time excess warm LNG will be flared.

2) Gas Freeing: 10 hours to achieve a tank hydrocarbon concentration of 2 percent by volume (gases will be sent to the tank relief and maintenance flare for the first nine hours, and to the tank maintenance cold vent for the final hour).

3) Aerating: 10 hours to achieve a safe, breathable atmosphere for tank inspection, during which time gases will be sent to the tank maintenance cold vent.

4) Tank Inspection: No gas flow will occur during the tank inspection.

5) Drying: 10 hours to achieve a dew point of -20 °C, during which time gases will be sent to the tank maintenance cold vent.

6) Inerting: 10 hours to achieve 2 percent O_2, and a dew point of -40 °C, during which time gases will be sent to the tank maintenance cold vent.

7) Gas-In: 10 hours to achieve 1.0 percent CO_2 by volume (gases will be sent to the tank maintenance cold vent for the first hour, and to the tank relief and maintenance flare for the remaining nine hours).

8) Cooldown: 10 hours to achieve an average tank temperature of -130 °C, during which time gases will be sent to the tank relief and maintenance flare.

Table 3-10 shows estimated annual GHG emissions due to LNG tank inspection activities. See Appendix B of this application for detailed calculations of emissions during each step of the process.

Table 3-10
FLSO LNG Tank Inspections – Potential Annual GHG Emissions

Pollutant	Vent emissions, tpy (per FLSO)	Flare emissions, tpy (per FLSO)	Total tpy for LNG Tank Inspections (per FLSO)
CO_2	28	616	644
CH_4	5.9	2.1	8.0
N_2O	0	1.1E-03	1.1E-03
CO_2e	175	669	844

3.1.10 LNGC Gas-in and Cooldown

EPNs: NFLSOTMEP (North FLSO)
SFLSOTMEP (South FLSO)

Most LNGCs receiving cargoes at the facility will arrive with a small heel of liquid LNG remaining in their cargo tanks, which will therefore already be cold and ready to receive cargo. However, it has been conservatively estimated that up to 20 LNGCs per year for the entire facility could arrive with warm, empty cargo tanks, which must be cooled prior to receiving cargo. Empty tanks will either contain warm methane vapor, which means the tanks must simply be cooled down, or will contain inert gas, which means they must be flushed first with LNG vapor, or "gassed-in," before being cooled, to prevent CO_2 in the inert gas from freezing into dry ice. It has been assumed for calculating potential emissions that up to 12 LNGCs per year for the entire facility could require gas-in and cooldown, and that an additional 8 LNGCs per year could require just a cooldown. The process is similar to that for LNG tank inspections described above, except that only two steps are required, a gas-in step that replaces inert gas with warm LNG vapor, and a cooldown step to achieve the required tank temperature for receiving LNG cargo.

For calculating potential emissions, an average LNGC capacity of 151,000 m^3 has been assumed, with four cargo tanks averaging 37,750 m^3 each. Given these parameters, it has been estimated that approximately 20 hours is required for gas-in of an entire LNGC, and that 10 hours is required for cooldown, based on documents and guidance provided by GTT. The introduced LNG vapor is assumed to have the same composition as "Net LNG to storage" provided in Appendix B, and the inert gas in the LNGC cargo tanks is assumed to have the same composition as that generated by the FLSO IGG. As with LNG tank inspections, gases containing at least 5 percent methane will be sent to the tank relief and maintenance flare, and gases containing less than 5 percent methane will be sent to the tank maintenance cold vent. Gases are assumed to be vented for the first hour of LNGC gas-in, and flared for the remaining 19 hours. Boil-off gas produced during cooldown may be used as fuel or returned to another LNG tank depending on operating conditions, but for worst-case potential emissions, it is assumed that all of the boil-off gas will be flared.

Table 3-11 shows estimated annual GHG emissions due to LNGC gas-in activities. See Appendix B of this application for detailed calculations of emissions during the process.

Table 3-11
LNGC Gas-In and Cooldown – Potential Annual GHG Emissions

Pollutant	Vent emissions, tons (per gas-in)	Flare emissions, tons (per gas-in)	Flare emissions, tons (per cooldown)	Total tpy for 12 LNGC gas-ins and 20 cooldowns (facility-wide)
CO_2	2.3	273	858	20,453
CH_4	3.4	0.81	3.0	111.0
N_2O	0	4.3E-04	1.6E-03	0.038
CO_2e	88	293	933	23,238

3.1.11 FLSO Fuel Oil Storage Tanks

EPNs: NFLSOFOTK1 through NFLSOFOTK5 (North FLSO)
SFLSOFOTK1 through SFLSOFOTK5 (South FLSO)

Each FLSO will be equipped with five fuel oil storage tanks, serving the essential generators, emergency generator, fire pump engines, incinerator, and IGG. Fuel oil will be stored in the forward machinery space in two storage tanks with capacities of 835 m^3 and 1,220 m^3, respectively, and two service tanks of 60 m^3 each. In the aft machinery space, the fire pump engines will share one 8 m^3 service tank. Potential vapor emissions from working losses and breathing losses have been estimated using the TANKS emissions estimation software program, Version 4.0.9d, based on potential annual consumption of ULSD on each FLSO. However, fuel oil vapor emissions are presumed to contain no CO_2, CH_4, or N_2O, and therefore do not result in any emissions of GHG.

3.1.12 Equipment Leak Fugitive Emissions

EPNs: NFLSOFUG (North FLSO)
SFLSOFUG (South FLSO)

Each FLSO will have fugitive emissions of natural gas and LNG vapor from valves, flanges, pumps, connectors and compressors seals that are an integral part of the design of the process for safety and maintenance purposes. Total numbers of components were minimized in accordance with LNG industry standards and estimated from engineering design documents for the Project. Fugitive emission factors for each component type were obtained from Table 4 of the January 2008 TCEQ document, "Emissions Factors for Equipment Leak Fugitive Components," which is an addendum to RG-360A, the TCEQ Emissions Inventory Guidelines.[10] Weight fractions of CO_2 and CH_4 in the fugitive gas were based on composition data for "Treated Gas" provided by the Project. (Treated gas is the stream sent to the FLSO from the onshore plant, after it has been stripped of CO_2 by the amine treatment system. See Appendix B of this application for detailed composition data.) Control efficiencies were then applied based on TCEQ's Leak Detection and Repair (LDAR) Program guidance document APDG 6129v2 for implementation of LDAR program 28 MID with auditory, visual and olfactory (AVO) inspections.[11] Potential emissions are shown in Table 3-12 below.

Table 3-12
FLSO Equipment Leak Fugitive GHG Emissions

Component	No. of Components (Total for both FLSOs)	Emission Factor (lb/hr-component)	Control Efficiency % (28MID with AVO)	Annual Controlled CO_2 Emissions (tpy)	Annual Controlled CH_4 Emissions (tpy)	Annual Controlled CO_2e Emissions (tpy)
Valves	3,792	0.00992	97	0	4.59	114.7
Flanges	7,584	0.00086	97	0	0.80	19.9
Compressor Seals	64	0.0194	95	0	0.25	6.3
Pumps	100	0.00529	93	0	0.15	3.8
Connectors	300	0.00044	97	0	0.016	0.40
TOTAL				0	5.80	145.0

Note: Emissions assume a reduction credit based on LDAR program 28 MID with AVO.

3.1.13 Insignificant GHG Emission Sources

Each FLSO also includes the following equipment, for which potential GHG emissions are assumed to be negligible, and have not been estimated.

- Each FLSO will be equipped with one incinerator for domestic, non-process waste, which will be a Hyundai-Atlas model with a supplemental fuel oil firing rate of approximately 2.9 MMBtu/hr. The incinerator will not be operated in state waters or while the FLSO is moored at the Project site, and therefore potential emissions will be zero.
- Each FLSO will be equipped with various lubricant and waste oil storage tanks. These tanks will store lubricating oil for the FLSO turbines and engines. The capacities and exact contents of these tanks will be determined later. Regardless, vapor emissions from lubricant and waste oil tanks are presumed to contain no GHG compounds.

3.1.14 Emission Sources Accounted for Elsewhere

The following emission sources have potential GHG emissions that are already accounted for as part of one or more other activities described in the sections above. For the sources listed below, it would be

[10] Texas Commission on Environmental Quality (TCEQ), "Emissions Factors for Equipment Leak Fugitive Components," Addendum to RG-360A, (January 2008), https://www.tceq.texas.gov/assets/public/implementation/air/ie/pseiforms/ef_elfc.pdf.
[11] Texas Commission on Environmental Quality (TCEQ), "Control Efficiencies for TCEQ Leak Detection and Repair Programs," APDG 6129v2 (July 2011), Microsoft Word file, http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSource Review/control_eff.doc.

difficult to characterize their emissions except as part of these other aforementioned activities. Here are brief summaries of these sources and where their potential emissions are included.

- Each FLSO will be equipped with 10 LNG storage tanks, each with a gross capacity of 25,100 m^3. Low-pressure boil-off gas (BOG) from the LNG storage tanks will be burned in the combustion turbines, re-liquefied and returned to the tanks, or lost as fugitive emissions from the LNG piping system. LNG vapor may also be sent to the tank relief and maintenance flare or tank maintenance cold vent when an LNG storage tank is emptied for periodic inspections. Potential GHG emissions from the LNG storage tanks are therefore reflected in the LNG tank inspection emissions presented in Section 3.1.9, and in the fugitive emissions calculated separately for the LNG piping system in Section 3.1.12.
- Each FLSO will be equipped with one low-pressure tank relief and maintenance flare located on the flare tower alongside the high-pressure cold and warm flares. This low-pressure flare will burn gases produced during “gas freeing” of the LNG storage tanks for periodic inspections, and during infrequent “gas-in” or “cooldown” operations for any LNGCs that arrive at the terminal with only inert gas or warm methane vapor in their cargo tanks. The low-pressure flare will also receive emergency releases of gas from the LNG storage tank relief valves. Potential GHG emissions from this source are reflected in the LNG tank inspection emissions presented in Section 3.1.9, and in the LNGC gas-in and cooldown emissions presented in Section 3.1.10.
- Each FLSO will also include a low-pressure tank maintenance cold vent, which will receive any gases from the LNG storage tanks or LNGCS that do not have a sufficient heating value to be flared. Potential GHG emissions from this source are reflected in the LNG tank inspection emissions in Section 3.1.9, and in the LNGC gas-in and cooldown emissions in Section 3.1.10.
- Each FLSO will be equipped with one inert gas generator (IGG), which will be an Aalborg “Smit Gas GIn 15.000- 0.25 BUFD” or similar model, with the capacity to generate 15,000 Nm^3/hour of inert gas, and a maximum heat input rate of approximately 62.5 MMBtu/hr firing diesel oil. The IGG is used to generate large quantities of inert (non-combustible) gas, which is used to inert the LNG storage tanks during maintenance, to inert LNG piping and the cargo machinery room, and to ventilate the ballast tanks. The IGG includes a single burner that burns fuel oil to generate combustion exhaust, which is then cooled and scrubbed with seawater, and dried to remove all traces of moisture. The resulting inert gas is approximately 85 percent nitrogen and 14 percent CO_2, with no more than 0.5 percent O_2 by volume, and trace amounts of other gases such as NO_x, CO and SO_2. (For the purpose of GHG emission calculations, the inert gas is assumed to contain no CH_4 or N_2O.) Potential GHG emissions from the IGG are reflected in the LNG tank inspection emissions in Section 3.1.9.

3.2 Onshore Facilities

Natural gas will be transported through a pipeline that will be connected to existing pipeline transmission systems to the onshore facilities. The gas will be treated onshore and transferred to the FLSO to be liquefied, stored and eventually transferred to LNGCs for delivery to markets.

3.2.1 Power Generation Turbines

EPNs: OSPT1 through OSPT7

The onshore facility will include seven natural gas fired combined cycle electric generation turbines, which will be Siemens SGT-400, or a similar model. Each turbine will be rated at approximately 13.4 MW of turbine shaft output power at 15 °C (59 °F) ambient, and guaranteed to provide 11.5 MW of electric generator output at 30 °C (86 °F) ambient. The maximum heat input rate will be approximately 145.5 MMBtu/hr at an ambient temperature of minus 3 °C. The combustion turbines will be equipped with heat recovery steam generators (HRSGs) to supply steam for two steam turbine electric generators, rated at approximately 6 MW each. Power from the generating turbines will be used to operate the feed gas compressors, as well as the entire onshore gas pre-treatment plant. For annual GHG emissions it is assumed that only six of the seven combustion turbines will operate at any given time, but that these six will operate for the equivalent of 8,760 hours per year at full load, with the seventh combustion turbine offline.

Table 3-13 shows a summary of the potential annual GHG emissions for a single onshore power generation turbine, and for the combined operation of all seven onshore turbines. Emission rates are based on vendor heat input information for steady-state full load operation. For all GHG pollutants, potential annual emissions are based on the 100% load case at 15 °C (59 °F) ambient temperature, with a per-turbine heat input rate of 142.4 MMBtu/hr. Emissions of CO_2, CH_4, and N_2O are calculated using the emission factors for general stationary fuel combustion sources in Subpart C of 40 CFR 98, which for natural gas combustion are: 53.06 kg CO_2/MMBtu, 0.001 kg CH_4/MMBtu, and 0.0001 kg N_2O/MMBtu. CO_2e emission rates use GWPs of 25 for CH_4, and 298 for N_2O, from Table A-1 of 40 CFR 98.

Table 3-13
Onshore Power Generation Turbines – Potential Annual GHG Emissions

Pollutant	tpy (per turbine)	tpy (facility-wide)
CO_2	72,977	437,864
CH_4	1.4	8.3
N_2O	0.14	0.83
CO_2e	73,053	438,316

3.2.2 Steam Boilers – Amine Regeneration

EPNs: OSSTBLR1 and OSSTBLR2

Two natural gas fired steam boilers will be located within the onshore facilities. Each boiler will have a maximum heat input rate of approximately 215.7 MMBtu/hr. Steam from the boilers will be used to regenerate the amine solution for the amine treatment units, which remove carbon dioxide and hydrogen sulfide from the feed gas. For annual potential GHG emissions it is assumed that each boiler may operate for up to 8,760 hours per year at full load. Table 3-14 shows potential annual GHG emissions for the steam boilers. Emissions of CO_2, CH_4, and N_2O are calculated using the emission factors for general stationary fuel combustion sources in Subpart C of 40 CFR 98, which for natural gas combustion are: 53.06 kg CO_2/MMBtu, 0.001 kg CH_4/MMBtu, and 0.0001 kg N_2O/MMBtu. CO_2e emission rates use GWPs of 25 for CH_4, and 298 for N_2O, from Table A-1 of 40 CFR 98.

Table 3-14
Onshore Steam Boilers – Potential Annual GHG Emissions

Pollutant	tpy (per boiler)
CO_2	110,514
CH_4	2.1
N_2O	0.21
CO_2e	110,628

3.2.3 Thermal Oxidizers – Amine Regeneration

EPNs: OSTO1 and OSTO2

The onshore facility will include two natural gas fired thermal oxidizers, which will be used to oxidize hydrogen sulfide (H_2S) and residual hydrocarbons in the waste gas stream produced from the amine stripper columns. The feed gas pre-treatment system uses an amine solution to remove CO_2 and H_2S from the incoming pipeline gas. Steam is then bubbled through this amine solution in the amine stripper columns to release the captured CO_2 and H_2S. This waste gas stream, which contains traces of methane as well as CO_2 and H_2S, is then burned in the thermal oxidizers. Each thermal oxidizer will have a supplemental heat input rate of approximately 89.0 MMBtu/hr, and will heat the waste gas stream to at least 800 °C. For annual potential GHG emissions it is assumed that each thermal oxidizer may operate for up to 8,760 hours per year at full load. Table 3-15 shows expected maximum short-term emission rates for the thermal oxidizers. CO_2 emissions are based on the outlet molar flow rate provided by Black & Veatch in their design documents for the Project. (This CO_2 flow rate is presumed to include both the CO_2 removed from the incoming feed gas, and the additional CO_2 produced by combustion of waste stream hydrocarbons and supplemental fuel.) CH_4 emissions assume 99.9 percent destruction of the inlet molar flow provided by Black & Veatch, plus CH_4 generated by combustion of supplemental fuel, using the natural gas emission factor of 0.001 kg CH_4/MMBtu in Subpart C of 40 CFR 98. CO_2e emission rates use GWPs of 25 for CH_4, and 298 for N_2O, from Table A-1 of 40 CFR 98.

Table 3-15
Onshore Thermal Oxidizers – Potential Annual GHG Emissions

Pollutant	tpy (per oxidizer)
CO_2	256,935
CH_4	1.3
N_2O	0.086
CO_2e	256,994

3.2.4 Regeneration Gas Heaters

EPNs: OSRGH1 and OSRGH2

The onshore facility will include two natural gas fired regeneration gas heaters, each with a maximum heat input rate of approximately 47.6 MMBtu/hr. These heaters are used to regenerate the molecular sieves in the pre-treatment plant's dehydration units, which remove all traces of moisture from the feed gas. When a molecular sieve becomes saturated with water, the regeneration gas heaters are used to heat a stream of incoming feed gas, which is passed through the dehydration unit to drive off the adsorbed water. This water is later condensed out of the feed gas and collected for disposal, while the feed gas stream is recycled back into the pre-treatment plant. For annual potential GHG emissions it is assumed that each regeneration gas heater may operate for up to 8,760 hours per year at full load. Table 3-16 shows potential annual GHG emissions for the regeneration gas heaters. Emissions of CO_2, CH_4, and N_2O are calculated using the emission factors for general stationary fuel combustion sources in Subpart C of 40 CFR 98, which for natural gas combustion are: 53.06 kg CO_2/MMBtu, 0.001 kg CH_4/MMBtu, and 0.0001 kg N_2O/MMBtu. CO_2e emission rates use GWPs of 25 for CH_4, and 298 for N_2O, from Table A-1 of 40 CFR 98.

Table 3-16
Regeneration Gas Heaters – Potential Annual GHG Emissions

Pollutant	tpy (per heater)
CO_2	24,388
CH_4	0.46
N_2O	0.046
CO_2e	24,413

3.2.5 Emergency Generators

EPNs: OSEGN1 and OSEGN2

The onshore facility will include two diesel oil fired emergency generators, which will be Caterpillar C175-16 engines, or a similar model. Each engine will be rated at approximately 3,000 kW of electric generator output, with a maximum heat input rate of approximately 31.1 MMBtu/hr. The emergency generators will operate to generate electricity for start up of the combined cycle combustion turbines, during emergencies, and for maintenance and testing. The emergency generators will be subject to the applicable standards under 40 CFR 60 Subpart IIII, which for an engine of this size and purpose, are the EPA Tier 2 standards for engines larger than 560 kW, as listed in 40 CFR 89.112. Fuel oil sulfur content will be limited to no more than 0.0015 percent by weight. For annual potential emissions it is assumed that each emergency generator will operate for up to 100 hours per year at full load. Table 3-17 shows potential annual GHG emissions for the emergency generators.

Table 3-17
Onshore Emergency Generators – Potential Annual GHG Emissions

Pollutant	tpy (per engine)
CO_2	253
CH_4	0.010
N_2O	2.1E-03
CO_2e	254

3.2.6 Fire Pump Engine

EPN: OSFP

The onshore facility will include one diesel oil fired fire pump engine, which will be a Cummins CFP7E-F30 engine, or a similar model. The engine will be rated at approximately 142 kW (190 horsepower [hp]) of shaft power output, with a maximum heat input rate of approximately 1.4 MMBtu/hr. The fire pump engine will operate during emergencies, and for maintenance and testing, and will be subject to the emission standards for fire pump engines in Table 4 of 40 CFR 60, Subpart IIII.

Fuel oil sulfur content will be limited to no more than 0.0015 percent by weight. For annual potential GHG emissions it is assumed that the fire pump engine will operate for up to 52 hours per year at full load. Table 3-18 summarizes the potential annual GHG emissions for the fire pump engine.

Table 3-18
Onshore Fire Pump Engine – Potential Annual GHG Emissions

Pollutant	tpy (per engine)
CO_2	6
CH_4	2.4E-04
N_2O	4.9E-05
CO_2e	6

3.2.7 Ground Flare

EPN: OSGF

The onshore facility will include one ground flare, which will be used for controlled depressurization of pre-treatment plant equipment prior to maintenance. The ground flare will be equipped with a pilot flame, but the pilot will only be lit during these planned depressurizations. Annual potential GHG emissions are based on one planned depressurization per year, using the estimated internal volume of a single gas pre-treatment train to determine the amount of gas combusted. Table 3-19 shows potential annual GHG emissions for the ground flare. Emissions of CO_2 and N_2O are calculated using the emission factors for general stationary fuel combustion sources in Subpart C of 40 CFR 98, which for natural gas combustion are: 53.06 kg CO_2/MMBtu, and 0.0001 kg N_2O/MMBtu. In accordance with TCEQ BACT guidance for flares, CH_4 emissions assume 99 percent destruction of all hydrocarbons in the flared gas that contain three or fewer carbons (CH_4, C_2H_6, and C_3H_8), which are all conservatively treated as methane for the purpose of the emission calculation.

Table 3-19
Onshore Ground Flare – Potential Annual GHG Emissions

Pollutant	tpy
CO_2	215
CH_4	0.75
N_2O	4.0E-04
CO_2e	234

3.2.8 Cooling Towers

EPNs: NCT1 through NCT12 (North cooling tower)
SCT1 through SCT12 (South cooling tower)

The onshore facility will include two onshore 12-cell wet cooling towers, which will provide cooling water for both the onshore pre-treatment plant, and for the FLSOs. The cooling towers will have a total inlet water flow of approximately 45,810 m^3 (12,101,700 gallons) per hour, with a maximum total heat rejection of approximately 3,874 MMBtu/hr. No GHG compounds are emitted from the cooling towers.

3.2.9 Condensate Storage and Loadout

EPNs: OSHCTK1 and OSHCTK2

The onshore gas pretreatment area will include two hydrocarbon condensate storage tanks, each with a capacity of approximately 132,084 gallons. The liquefaction process onboard the FLSOs will cause trace amounts of heavier hydrocarbons (such as butane, propane, etc.) to condense out of the treated feed gas as it cools. These hydrocarbon condensates will be piped onshore into the condensate storage tanks, where they will be stored until removed periodically by tanker trucks. The collected condensates will be sold to other petrochemical facilities for use in a variety of products. It is estimated that daily condensate production from each FLSO may range from 0 gallons per day up to nearly 51,000 gallons per day depending on feed gas composition. About 89 percent of the condensate will consist of pentane and heavier alkanes on a molar basis, including approximately 27 percent hexane and approximately two percent benzene. The composition data provided by the Project (see Appendix B of this application) indicate that vapor emissions from condensate storage and loadout will not contain any CO_2, CH_4, or N_2O, and therefore will not result in any emissions of GHG.

3.2.10 Onshore Fuel Storage Tanks

EPNs: OSFOTK1 through OSFOTK3

Each onshore engine will include its own fuel storage tanks. No tank sizes or dimensions have been selected yet, so reasonable estimates of tank capacity were made based on the potential annual fuel use for each engine. Potential vapor emissions from working losses and breathing losses have been estimated using TANKS 4.0.9d. However, fuel oil vapor emissions are presumed to contain no CO_2, CH_4, or N_2O, and therefore do not result in any emissions of GHG.

3.2.11 Equipment Leak Fugitive Emissions

EPN: OSFUG

The onshore facility will have fugitive emissions of natural gas from valves, flanges, pumps, connectors and compressors seals that are that are an integral part of the design of the process for safety and maintenance purposes. Total numbers of components were minimized in accordance with LNG industry standards and estimated from engineering design documents for the Project. Fugitive emission factors for each component type were obtained from Table 4 of the January 2008 TCEQ document, “Emissions Factors for Equipment Leak Fugitive Components.” Weight fractions of CO_2 and CH_4 in the fugitive gas were based on composition data for “Feed Gas” provided by the Project. (Feed gas is the untreated stream entering the onshore plant from the pipeline header system. See Appendix B of this application for detailed composition data.) Control efficiencies were then applied based on TCEQ’s LDAR Program guidance document APDG 6129v2 for implementation of LDAR program 28 MID with AVO inspections. Potential emissions are shown in Table 3-20 below.

Table 3-20
Onshore Equipment Leak Fugitive GHG Emissions

Component	No. of Components (Total for both FLSOs)	Emission Factor (lb/hr-component)	Control Efficiency % (28MID with AVO)	Annual Controlled CO_2 emissions (tpy)	Annual Controlled CH_4 emissions (tpy)	Annual Controlled CO_2e emissions (tpy)
Valves	3,000	0.00992	97	0.14	3.5	87.8
Flanges	6,000	0.00086	97	0.023	0.61	15.2
Compressor Seals	10	0.0194	95	1.5E-03	0.038	1.0
Pumps	20	0.00529	93	1.1E-03	0.029	0.73
Connectors	1,560	0.00044	97	3.1E-03	0.081	2.0
TOTAL				0.16	4.3	106.7

Note: Emissions assume the gas to be 1.56% VOC, and assume a reduction credit based on LDAR program 28 MID with AVO.

3.2.12 Insignificant Emission Sources

The onshore facility also includes the following equipment, for which potential emissions are assumed to be negligible, and have not been estimated.

- The onshore facility will include one cold vent, for the disposal of high-pressure hydrocarbon vapors under emergency situations. The cold vent system will collect all discharges from pressure relief and emergency depressurization valves, and is designed for a worst-case gas relief rate of approximately 215,000 kg/hour. The onshore cold vent will operate only during emergencies, which are anticipated to occur very infrequently, if ever. The onshore cold vent is therefore not included in the facility's potential emissions.
- Two amine make-up tanks. These tanks will store amine solution for the amine stripping process, with an estimated volume of 50,985 gallons each. The exact volume and dimensions of these tanks will be determined later. The amine compounds typically used in this process have an extremely low vapor pressure, and potential emissions are expected to be negligible.
- Various lubricant and waste oil storage tanks. These tanks will store lubricating oil for the onshore turbines and engines. The capacities and exact contents of these tanks will be determined later. Regardless, emissions will be negligible due to low vapor pressure and thus have not been estimated.
- VOC emissions from the oily water treatment package are expected to be negligible.

3.3 Site-Wide Annual Potential GHG Emissions

Tables 3-21 and 3-22 present the combined total annual potential GHG emissions (in tons/year) for each type of Project emission source, grouped by facility area. Table 3-23 summarizes annual potential site-wide total emissions.

Table 3-21
Marine Facilities Annual Potential GHG Emissions (tons/yr)

Source Type (number of units)	CO_2	CH_4	N_2O	CO_2e
Refrigerator Compressor Turbines (8)	2,191,437	206.6	4.1	2,197,833
Compressor Turbine Startup/ Shutdown	0	0.79	0	20
Power Generation Turbines (6)	733,445	43.1	1.4	734,935
Essential Generators (4)	11,067	0.45	0.090	11,105
Emergency Generators (2)	98	4.0E-03	7.9E-04	98
Fire Pump Engines (4)	298	0.012	2.4E-03	299
Cold Flare (2)	11,196	39.3	0.021	12,185
Warm Flare (2)	11,161	39.1	0.021	12,145
LNG Tank Inspection (all tanks)	1,288	16.0	2.3E-03	1,688
LNGC Gas-In and Cooldown (all LNGCs)	20,453	111.0	0.038	23,238
Fugitive Emissions	0	5.8	0	145
TOTAL	**2,980,444**	**462.1**	**5.7**	**2,993,691**

Table 3-22
Onshore Facilities Annual Potential GHG Emissions (tons/yr)

Source Type (number of units)	CO_2	CH_4	N_2O	CO_2e
Power Generation Turbines (7)	437,864	8.3	0.83	438,316
Steam Boilers (2)	221,029	4.2	0.42	221,257
Thermal Oxidizers (2)	513,870	2.6	0.17	513,987
Regeneration Gas Heaters (2)	48,776	0.92	0.092	48,826
Emergency Diesel Generators (2)	507	0.021	4.1E-03	508
Diesel Fire Water Pump	6	2.4E-04	4.9E-05	6
Onshore Ground Flare (1)	215	0.75	4.0E-04	234
Onshore Fugitive Emissions	0.16	4.3	0	107
TOTAL	**1,222,266**	**21.0**	**1.5**	**1,223,242**

Table 3-23
Site-Wide Annual Potential GHG Emissions (tons/yr)

Source	CO_2	CH_4	N_2O	CO_2e
Marine Facilities Emissions	2,980,444	462.1	5.7	2,993,691
Onshore Facilities Emissions	1,222,266	21.0	1.5	1,223,242
SITE-WIDE TOTAL	**4,202,710**	**483.1**	**7.2**	**4,216,932**

4.0 REGULATORY REVIEW AND APPLICABILITY

EPA and TCEQ have promulgated regulations that establish ambient air quality standards and emission standards for sources of air pollution. These regulations, as they relate to GHG emissions, and their potential applicability to the Project are reviewed in this section.

The EPA is authorized by the Clean Air Act (CAA), 42 USC 7401 et seq., as amended in 1977 and 1990, to promulgate regulations governing air pollution in the United States, which are codified in Title 40 of the CFR, Parts 50 through 99. The TCEQ's air permitting requirements are codified in Title 30 of the Texas Administrative Code (30 TAC). These requirements implement or incorporate the applicable federal regulations in 40 CFR Parts 50-99, and establish permit review procedures for all facilities that can emit pollutants to the ambient air.

New facilities are required to obtain an air quality permit from TCEQ prior to commencing construction. No other pre-construction air quality permits are generally required. However, since EPA has not yet approved TCEQ's PSD program for GHG, EPA currently has PSD air permitting authority for GHG emissions from the Lavaca Bay LNG Project. This application is therefore being concurrently submitted to EPA Region 6 and TCEQ.

The federal and state regulations that are potentially applicable to the GHG emissions from the Project include:

- Prevention of Significant Deterioration;
- Title V Operating Permit; and
- Greenhouse Gas Reporting.

4.1 Prevention of Significant Deterioration

PSD is a federally-mandated review program that applies to new major stationary sources, and major modifications of existing sources, in areas designated as attainment or unclassifiable with respect to the National Ambient Air Quality Standards (NAAQS) that EPA has established for six non-GHG pollutants referred to as "criteria" pollutants. While no NAAQS value has been established for GHG, the PSD program has been modified to include review of major sources of GHG emissions.

Consistent with EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), an applicant is not required to model or conduct ambient monitoring for GHGs, nor is any assessment of impacts of GHGs in the context of the additional impacts analysis or PSD Class I area provisions. Instead, compliance with the BACT analysis is the proper technique to be employed to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs.

The emission threshold for major stationary sources varies under PSD according to the type of facility. A facility is considered major under PSD if it emits or has the potential to emit 250 tpy or more of any criteria pollutant, or 100 tpy if it belongs to one of 28 categories of stationary sources listed under 40 CFR 52.21 (b)(1)(i). The Lavaca Bay LNG Project is subject to the 100 tpy PSD threshold because it includes a combined-cycle electric generating plant, which falls into the listed source category for fossil fuel-fired steam electric plants with a heat input of more than 250 MMBtu per hour.

The EPA published final rules for permitting major sources of GHGs on June 3, 2010, known as the PSD and Title V Greenhouse Gas Tailoring Rule.[12] After July 1, 2011, new sources are subject to PSD permitting requirements if they have the potential to emit *both* 250 tpy or more of GHGs on a mass basis *and* 100,000 tpy or more of GHGs on a CO_2e basis.

Table 4-1 lists the PSD major source emission rate thresholds for GHG. The proposed facility will be a new source capable of emitting greater than 250 tpy of GHGs on a mass basis and 100,000 tpy of CO_2e. As a result, ELO Port Lavaca is required to obtain a PSD GHG air permit.

Table 4-1
PSD GHG Regulatory Thresholds and Project Potential Emissions

Pollutant	Project Potential Annual Emissions (tons)	PSD Major Source Threshold (tons)	PSD Review Applies
CO_2	4,202,710	250 tpy (for sum of all individual gases on a mass basis)	Yes
CH_4	483.1		
N_2O	7.2		
GHGs (as CO_2e)	4,216,932	100,000	Yes

4.2 Title V Operating Permit

The Project is subject to New Source Performance Standards (NSPS) and will have potential emissions greater than 100 tpy for at least one criteria pollutant, and will therefore be subject to the Title V operating permit requirements under 40 CFR 70 (including the Title V portion of EPA's Greenhouse Gas Tailoring Rule). TCEQ has been delegated authority by EPA to administer the federal Title V operating permit program under its regulations at 30 TAC Chapter 122. Affected facilities are required to submit an operating permit application to TCEQ prior to commencement of operation.

4.3 Greenhouse Gas Reporting

On November 8, 2010, EPA signed a rule that finalizes reporting requirements for the petroleum and natural gas industry under 40 CFR Part 98.[13] Subpart W of 40 CFR Part 98 requires petroleum and natural gas facilities that have actual GHG emissions of 25,000 metric tons or more of CO_2e per year to report annual emissions of specified GHGs from various processes within the facility and conduct associated monitoring. LNG storage and LNG import and export equipment are considered part of the source category regulated by Subpart W. Therefore, since actual emissions from the proposed Project are expected to exceed the 25,000 metric ton threshold, ELO Port Lavaca will be required to comply with all applicable requirements of the rule.

[12] 75 FR 31513, Jun. 3, 2010.
[13] 75 FR 74488, Nov. 30, 2010.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

5.1 Introduction

EPA regulations require that the BACT be applied to each new and modified facility that emits an air pollutant for which a significant net emissions increase will occur from the source or modification. The only PSD pollutant addressed in this permit application is GHG.

GHG, as a PSD air pollutant, is defined at 40 CFR 51.166(b)(48) to be the aggregate group of six greenhouse gases: CO_2, N_2O, CH_4, HFCs, PFCs, and SF_6. CO_2, N_2O, and CH_4 are all emitted as byproducts of fuel combustion. CO_2 and CH_4 can also be constituents of natural gas and LNG vapor that enters the atmosphere either through purpose-designed vents, or as fugitive emissions from process components such as valves, flanges, and seals. ELO Port Lavaca will not include any potential sources of HFCs and PFCs, which are used primarily in commercial refrigeration and air conditioning equipment; or of SF_6, which is used chiefly as an insulating gas inside electrical switchgear produced by certain manufacturers.

Therefore, a GHG BACT analysis has been completed for the following types of equipment, as presented in the following sections:

- Section 5.2 – Combustion Turbines (FLSO refrigerator compressor turbines, FLSO power generation turbines, and onshore power generation turbines);
- Section 5.3 – Generator Engines and Fire Pump Engines (FLSO essential generators, FLSO emergency generators, FLSO fire pump engines, onshore emergency generators, and onshore fire pump engine);
- Section 5.4 – Boilers and Heaters (onshore steam boilers and onshore regeneration gas heaters);
- Section 5.5 – Amine Unit Thermal Oxidizers;
- Section 5.6 – Flares;
- Section 5.7 – Tank Maintenance Cold Vents; and
- Section 5.8 – Fugitives.

5.1.1 Definition of BACT

40 CFR 52.21(b)(12) defines “Best Available Control Technology” as:

> An emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may

be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

5.1.2 BACT Methodology

The PSD regulations do not prescribe a procedure for conducting BACT analyses. Instead, the EPA has consistently interpreted the BACT requirement as containing two core criteria: First, the BACT analysis must include consideration of the most stringent available technologies, *i.e.*, those that provide the "maximum degree of emissions reduction." Second, any decision to require as BACT a control alternative that is less effective than the most stringent available must be justified by an analysis of objective indicators showing that energy, environmental, and economic impacts render the most stringent alternative unreasonable or otherwise not achievable.

EPA has developed what it terms the "top-down" approach for conducting BACT analyses and has indicated that this approach will generally yield a BACT determination satisfying the two core criteria. Under the "top-down" approach, progressively less stringent control technologies are analyzed until a level of control considered BACT is reached, based on the environmental, energy, and economic impacts. The top-down approach utilized in this BACT analysis is discussed in detail in the 1990 EPA guidance document, *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting* ("NSR Manual").[14] In addition to the 1990 NSR Manual, the BACT analysis pertaining to GHG has been conducted in accordance with EPA's 2011 guidance document, *PSD and Title V Permitting Guidance for Greenhouse Gases*.[15] The 2011 guidance document refers to the same top-down methodology described in the 1990 document, and it provides additional clarification and detail with regard to some aspects of a BACT analysis for GHGs.

5.1.3 Top-Down BACT Process

The Top-Down BACT process in the NSR Manual involves the following five steps:

Step 1: Identify all potential control technologies applicable to the pollutant and process.

Step 2: Determine the technical feasibility of each control technology identified under Step 1 as applicable to the proposed facility and eliminate those that are infeasible.

Step 3: Rank the remaining control technologies based on achievable overall control effectiveness.

Step 4: Evaluate the most effective control technology based on economic, energy, and environmental factors. If the most effective control technology is not feasible as a result of economic, energy, or environmental factors, the next most effective technology is evaluated. This process continues until a technology is selected. If the top ranked technology is chosen as the BACT, it is not necessary to review the economic, environmental, and energy factors.

[14] U.S. Environmental Protection Agency (EPA), *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting* (Research Triangle Park, NC: EPA Office of Air Quality Planning and Standards, Draft October 1990), http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf.

[15] U.S. Environmental Protection Agency (EPA), *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA-457/B-11-001 (Research Triangle Park, NC: EPA Office of Air Quality Planning and Standards, Air Quality Policy Division, March 2011), http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.

Step 5: Select as BACT the most effective option not eliminated in Steps 2 – 4 above and corresponding emission limit for the pollutant.

The application of each of these five steps for the proposed facility's GHG emissions is discussed in the following sections. In Step 1, the applicant must identify all "available" control options which have the potential for practical application to the emission unit and regulated pollutant under evaluation, including lower-emitting processes and practices. In assessing available GHG control measures, we reviewed EPA's RACT/BACT/LAER Clearinghouse, Southern Research's Greenhouse Gas Mitigation measures, the South Coast Air Quality Management District's BACT determinations, and the EPA Region 6 website.[16] According to the Region 6 website, no liquefaction facilities in Region 6 have received an EPA-issued GHG PSD permit to date (and thus there are no EPA Region 6 final GHG BACT determinations for liquefaction facilities). However, EPA has issued draft GHG permits for the Freeport LNG and the Corpus Christi LNG projects, and a number of non-LNG turbine facilities have received GHG PSD permits from Region 6. These draft and final permits were reviewed and the most relevant are summarized in the following section.

5.1.4 Context for GHG BACT Analysis

The evaluation and selection of BACT for ELO Port Lavaca's proposed GHG emissions sources is limited to consideration of control technologies that are potentially feasible for the Project *as designed*. The proposed layout and equipment fleet for the Project have been selected to fulfill specific aims, and consideration of technologies that would amount to altering the basic design of the Project's pre-treatment, liquefaction, or storage facilities (such as replacing combustion turbines with electric motors) is beyond the scope of EPA's regulatory power in determining what constitutes BACT. EPA has repeatedly identified two principles that limit the application of BACT:

- Only the applicant may define the project's purpose and objectives.
- BACT cannot require measures that would redefine the source.

These two principles are addressed in the discussion below.

Definition of the project's purpose and objectives. The Project has been designed to provide for the safe, reliable and cost-effective production of LNG for export using proven and demonstrated technologies. The FLSO design was carefully selected to meet Excelerate's business objectives using the PRICO liquefaction trains. Excelerate's design philosophy for the FLSO was to maintain autonomy onboard, i.e., complete independence from land-based power supplies. This was done specifically to preclude the necessity of being dependent on the South Texas power grid to assure stringent uptime requirements to support commercial LNG offtake agreements. A study of electric-driven refrigerator compressors was carried out during the autonomy investigations and it became clear that the complexity of the grid supply to the FLSO via numerous, large-diameter electric cables, suitably flexible to be capable of vessel draft and tidal range fluctuations, was not only technically challenging, but also commercially infeasible, and presented serious safety concerns for operating personnel. The same philosophy exists for the onshore portions of the Project more in order to maintain high reliability requirements necessary for commercial LNG production.

[16] "RACT/BACT/LAER Clearinghouse (RBLC)," U.S. Environmental Protection Agency (EPA), last modified May 26, 2014, http://cfpub.epa.gov/rblc/; "Greenhouse Gas Mitigation," Southern Research Institute, accessed May 26, 2014, http://www.southernresearch.org/environment-energy/greenhouse-gas-mitigation; "BACT Main Page," South Coast Air Quality Management District, last modified October 21, 2013, http://www.aqmd.gov/bact/; "Air Permits | EPA Region 6," last modified March 4, 2013, http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

The turbines were selected to drive the PRICO liquefaction trains and provide electrical power based on the size, efficiency, and reliability of those turbines. For the FLSO and onshore power turbines, waste heat from the turbines has been designed to be recovered to increase overall efficiency. For the FLSO power turbines, excess heat from the exhaust gas is used to heat mineral oil used in various processes aboard the FLSO. For the onshore turbines, excess heat from the exhaust gas will be used in an efficient combined cycle configuration whereby an additional 12 MW of power will be generated from steam produced by the waste heat of the combustion turbines.

As defined, BACT applies to the facilities and emission units that will be operated by ELO Port Lavaca. Alternative production processes, methods, systems, or techniques that would result in wholesale replacement of a proposed facility, or that would be inconsistent with the fundamental objectives and basic design of the Project, would impermissibly redefine the source and need not be included in the BACT analysis.

EPA has had a long-standing policy regarding the responsibility of the project proponent in defining the key elements and purpose of a project. This policy was described by the Environmental Appeals Board (EAB) in its order denying review of the BACT determination for Prairie State Generating Company (PSD Appeal No. 05-05):

> The real conflict here concerns who is the appropriate entity to identify the facility's purpose or basic design. Petitioners essentially maintain that this role falls to [the permitting authority], independent of how the applicant articulates the project in its permit application… Petitioners' argument, however, does not explain how the permit issuer is to identify the proposed Facility's basic purpose and, thus, it offers no clear standard for doing so. We must reject this approach and instead conclude the statute contemplates that the permit issuer looks to how the permit applicant defines the proposed facility's purpose or basic design in its application, at least where that purpose or design is objectively discernable, as it is here.
>
> Our conclusion flows from the specific statutory words and phrases identified both by Petitioners and OAR and from Congress' establishment of the PSD program as a permitting system that is initiated by an application from the owner or operator of a proposed source… The specific statutory words in the definition of BACT (i.e., processes, methods, systems, and techniques) that Petitioners point to as including the "means" but excluding the "facility's 'end,' 'object,' 'aim,' or 'purpose'" from BACT review must not be read in isolation, but instead are a part of a permit application process that requires the "proposed facility" to be subject to BACT. In this context, the permit applicant initiates the process and, in doing so, we conclude, defines the proposed facility's end, object, aim, or purpose – that is the facility's basic design, which no doubt will be reflected in the permit applicant's schematic design for the proposed facility….
>
> For these reasons, we conclude that the permit issuer appropriately looks to how the applicant, in proposing the facility, defines the goals, objectives, purpose, or basic design for the proposed facility. Thus, the permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility, and therefore, the permit issuer must discern which design elements are inherent to that purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve

> pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility.[17]

The U.S. Court of Appeals for the Seventh Circuit later upheld the EAB decision.[18]

BACT cannot require measures that would redefine the source. For proposed natural gas-fired combustion turbines at electric generating facilities, EPA or the EAB have recently deferred to the project proponent in identifying the generating technology which best meets the scope and purpose of a project. EPA accepted the applicant's proposal to use simple-cycle combustion turbines in making the BACT determination for the Cheyenne Prairie Generating Station rather than more efficient turbines in order to achieve "consistency with other locations." In that case, EPA stated that the selection of a fleet of like turbines for different locations provides advantages with knowledge of maintenance and operations, stocking of spare parts, and ability to swap turbines between locations.

Similarly for the Pio Pico Energy Center, EPA accepted the applicant's BACT proposal to use simple-cycle combustion turbines rather than more efficient combined-cycle technology because the latter would be inconsistent with the business purpose and fundamental design elements of the project.[19]

Finally, in the recent order denying review of the BACT determination for La Paloma Energy Center (PSD Appeal No. 13-10), the EAB found the following:

> Sierra Club has failed to demonstrate that the Region clearly erred or abused its discretion in establishing the GHG permit limits for the combustion turbines at the proposed LPEC facility. The Board finds no support in EPA's BACT guidance for Sierra Club's position that the three specific turbine models proposed by LPEC must be identified as separate control technologies throughout the Region's five-step analysis. The Region had a rational basis for its determinations that all three of the permitted turbine models are comparably efficient on a performance basis, that the assigned BACT limits are substantially equivalent except for marginal differences attributable to capacity, and that the GHG emission limits for all three turbine models represent BACT for highly efficient combined cycle combustion turbines.
>
> Sierra Club has failed to demonstrate that the Region abused its discretion in concluding that adding solar technology to this facility would "redefine the source." Under the circumstances of this case, the business purposes and site-specific constraints described in the administrative record support the Region's conclusion that the addition of supplemental solar power to this facility would constitute redesign of the source.[20]

A Texas court and Texas administrative proceedings have also maintained that the BACT review process cannot be used to redefine the source proposed by the applicant. In *Blue Skies Alliance v. Texas Commission on Environmental Quality*, the Amarillo court of appeals rejected a claim that an applicant proposing a coal-fired power plant should have to consider replacing a proposed facility, pulverized coal boilers, with integrated gasification combined cycle technology. The court held:

> BACT requires that those production processes, methods, systems, and techniques (control technologies) that will achieve the maximum reduction of regulated pollutants be **applied** to any **proposed** major stationary source. We believe that the BACT definition clearly provides that

[17] *In re Prairie State Generating Company*, 13 E.A.D. 1 (EAB 2006).
[18] *Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007).
[19] *In re Pio Pico Energy Center,* PSD Appeal Nos. 12-04, 12-05, & 12-06 (EAB Aug. 2, 2013), 16 E.A.D. ___.
[20] *In re La Paloma Energy Center, LLC*, PSD Appeal No. 13-10 (EAB Mar. 14, 2014), 16 E.A.D. ___.

> only those control technologies that can be applied to the proposed major source be considered in the BACT analysis. Thus, the only control technologies that must be considered in a BACT analysis are those control technologies that can be incorporated into or added to the facility as proposed by the applicant.[21]

The Texas State Office of Administrative Hearings ("SOAH") recently reaffirmed this principle for a proposed LNG export facility, citing *Blue Skies Alliance* and determining that, "In the ALJs' opinion, the use of electrically-driven compression is not a production process that can be applied to the source proposed by CCL; it is a complete replacement of the emission source itself."[22] SOAH also determined that the proposed simple-cycle turbines were essential to the applicant's business objectives for the proposed LNG export facility.

5.2 Combustion Turbines

Step 1: Identify Potentially Feasible GHG Control Options

A review of recently-issued and draft GHG PSD permits for proposed new combustion turbines found that GHG BACT is generally defined as energy-efficient design and good combustion practices, in the form of limits on heat input rate and CO_2e emissions per unit of output. GHG BACT determinations also generally specify GHG tpy limits in the form of CO_2e, and in a few cases, for the individual constituent compounds of CO_2, CH_4, and N_2O, as well. Rate limits for GHG are mainly specified as pounds per megawatt-hour (lb/MWh) of CO_2e (on either a gross or net MWh basis, which varies by permit). Occasionally rate limits are specified as lb CO_2/MWh, or as lb CO_2e per unit of product output. Compliance is typically calculated on a 12-month rolling average basis, although shorter averaging periods, and rolling updates as frequent as daily, are also found. Table 5-1 summarizes the relevant recently-issued GHG BACT determinations for simple cycle turbines. Although some of these have not been included in any relevant GHG BACT determinations, the following technologies are considered to be potentially feasible control options for the ELO Port Lavaca combustion turbines:

- Low carbon-emitting fuels
- Energy efficiency
- Good combustion, operating and maintenance practices
- Carbon capture and storage (CCS)

Each of these control options is discussed in detail in Step 2 of the combustion turbine GHG BACT analysis.

[21] *Blue Skies Alliance v. Texas Comm'n on Envt'l Quality*, 283 S.W.3d 525, 535 (Tex.App.—Amarillo 2009, no pet.) (emphasis in original).
[22] *In re Application of Corpus Christi Liquefaction LLC for Air Quality Permit Nos. 105710 and PSD-TX-1306 for the Construction of a Natural Gas Liquefaction and Export Terminal with Regasification Capabilities*, SOAH Docket No. 582-13-5205, TCEQ Docket No. 2013-1191-AIR, Proposal for Decision at 29 (May 15, 2014).

Table 5-1
Recent Relevant GHG BACT Determinations for Simple Cycle and Compressor Turbines

Company / Location	Permit Reference No.	Year Permit Issued	Process Description	Control Technology	GHG BACT Emission Limit / Requirements
Indeck Wharton Energy Center Danevang, TX	PSD-TX-1374-GHG	2014	Simple cycle combustion turbine	Energy-efficient design & good combustion practices	1,276 lb CO_2/MWh (gross) for GE 7FA.05 option 1,337 lb CO_2/MWh (gross) for Siemens SGT-5000F(5) option 2,500 operating-hour rolling basis, rolling daily, each turbine
EFS Shady Hills, LLC EPA Region 4	PSD-EPA-R4013	2014	Simple cycle combustion turbine	Energy-efficient design & good combustion practices	1,377 lb CO_2e/MWh (gross) when firing natural gas
Copano Processing, L.P. Houston Central Gas Plant	PSD-TX-104949-GHG	2013	Compressor turbine with waste heat recovery	Energy-efficient design & good combustion practices	Maintain a minimum thermal efficiency of 40% with WHRU on a 12-month rolling average basis (equal to 0.84 lb CO_2e/hp-hr)
LADWP Scattergood Generating Station Playa Del Ray, CA	800075	2013	Simple cycle combustion turbine	Energy-efficient design & good combustion practices	1,271 lb CO_2e/MWh (net) 12-month rolling average
Puget Sound Energy Freedonia Generating Station Bellevue, WA	PSD-11-05	2013	Simple cycle combustion turbine	Energy-efficient design & good combustion practices	1,299 lb CO_2e/MWh (net) for GE 7FA.05 1,310 lb CO_2e/MWh (net) for GE 7FA.04 1,278 lb CO_2e/MWh (net) for SGT6-5000F4 1,138 lb CO_2e/MWh (net) for GE LMS100
Pio Pico Energy Center, LLC Otay Mesa, CA	SD 11-01	2012	300 MW simple cycle power plant	Energy-efficient design & good combustion practices	1,328 lb CO_2e/MWh (gross) 720 operating-hour rolling average
York Plant Holding, LLC Springettsbury Township, PA	67-05009C*	2012	Simple cycle combustion turbine	Energy-efficient design & good combustion practices	1,330 lb CO_2e/MWh (net) 30-day rolling average Combustion turbine annual net heat rate limited to 11,389 Btu/kWh (HHV) when firing natural gas
Cheyenne Light, Fuel & Power / Black Hills Power, Inc. Laramie County, WY	PSD-WY-000001-2011.001	2012	Simple cycle combustion turbine	Energy-efficient design & good combustion practices	1,600 lb CO_2e/MWh (gross) 365-day rolling average

Company / Location	Permit Reference No.	Year Permit Issued	Process Description	Control Technology	GHG BACT Emission Limit / Requirements
El Paso Electric Company Montana Power Station El Paso, TX	PSD-TX-1290-GHG	Draft (2014)	Simple cycle combustion turbine	Energy-efficient design & good combustion practices	1,194 lb CO_2/MWh (gross) 5,000 operating-hour rolling average
Freeport LNG Development Freeport LNG Freeport, TX	PSD-TX-1302-GHG	Draft (2014)	Simple cycle combustion turbine	Energy-efficient design & good combustion practices	738 lb CO_2e/MWh (net) 365-day rolling average
Corpus Christi Liquefaction, LLC LNG Terminal Gregory, TX	PSD-TX-1306-GHG	Draft (2014)	Compressor turbine with & without waste heat recovery	Energy-efficient design & good combustion practices	8,041 lb CO_2e/MMscf of LNG produced 12-month rolling average

Step 2: Eliminate Technically Infeasible Options

Low carbon-emitting fuels. As described in this application, combustion turbine technology and the use of natural gas as a fuel source are fundamental to the primary purpose and business objectives of the project. Therefore, in accordance with EPA's 2011 guidance document for GHG permitting, the GHG BACT analysis does not need to include an analysis of alternative fuels, which would redefine the source.[23] In addition, while biofuels would reduce fossil fuel-based carbon emissions, the use of biofuels in combustion turbines has issues that have yet to be resolved, including high sodium and potassium content, which causes spalling of the thermal barrier coating, and a tendency for biofuel to turn into a jelly-like substance at low temperatures. Fuel tanks would require heaters to prevent gelling, as well as nitrogen blankets to keep the fuel from coming into contact with oxygen (which causes biofuels to degrade). For these reasons, biofuels are not technically feasible.

Among the remaining feasible fuel options, natural gas combustion, as proposed here, generates significantly lower CO_2 emissions per unit of heat input than distillate oil or coal, as shown in Table 5-2.

Table 5-2
Comparison of Typical CO_2e Emission Rates for Fossil Fuels

Fuel	CO_2 (lb/MMBtu)	CH_4 (lb/MMBtu)	N_2O (lb/MMBtu)	CO_2e (lb/MMBtu)
Natural Gas*	116.9	0.0022	0.00022	117.01
Distillate Oil*	162.3	0.0066	0.0013	162.84
Coal**	242	0.016	0.0032	243.33

*Emission rates for natural gas and distillate oil are based on default emission factors from 40 CFR Part 98, Subpart C.

**The CO_2 emission rate for coal is based on Table 1.1-20 of EPA *AP-42*, assuming medium-volatile bituminous coal and a heat content of 12,500 Btu/lb. CH_4 and N_2O emission rates are based on Table 1.1-19 of EPA AP-42, assuming a PC-fired dry bottom, tangentially fired boiler, and a heat content of 12,500 Btu/lb.

Energy efficiency: Overview. EPA's 2011 guidance document for GHG permitting addresses the particular significance of energy efficiency for GHG BACT analyses:

> The application of methods, systems, or techniques to increase energy efficiency is a key GHG-reducing opportunity that falls under the category of "lower-polluting processes/practices." Use of inherently lower-emitting technologies, including energy efficiency measures, represents an opportunity for GHG reductions in these BACT reviews… Applying the most energy efficient technologies at a source should in most cases translate into fewer overall emissions of all air pollutants per unit of energy produced…. For these reasons, EPA encourages permitting authorities to use the discretion available under the PSD program to include as available technologies in Step 1 the most energy efficient options in BACT analyses for both GHG and non-GHG regulated NSR pollutants. While energy efficiency can reduce emissions of all combustion-related emissions, it is a particularly important consideration for GHGs since the use of add-on controls to reduce GHG emissions is not as well advanced as it is for most combustion-derived pollutants.[24]

Given that GHG emissions from combustion turbine operations are primarily a function of the amount of fuel burned, maximizing efficiency may also be thought of as minimizing the heat rate. The heat rate of a

[23] EPA, *GHG Permitting Guidance*, pp. 26-28.
[24] Ibid., p. 29.

combustion turbine is the amount of heat input required to generate a unit of work output, commonly measured as British thermal units of heat input per kilowatt-hour of output (Btu/kWh), where kWh may represent either the output from an electric generator (for power generation turbines), or the direct mechanical work produced at the turbine shaft (for mechanical drive turbines). The primary design considerations that affect the overall heat rate of a combustion turbine are:

- Modern design;
- Turbine type;
- Use of waste heat;
- Inlet air cooling; and
- Operating load range.

MODERN DESIGN. Older, more inefficient turbines consume more fuel to generate the same amount of power as newer, more efficient turbines. These efficiency differences are due to equipment wear and tear in older units, and improved design in newer models, including the use of higher quality metallurgy. Use of modern turbine design is a technically feasible option for energy efficiency, and all of the turbines selected for the Project will be new units designed with modern turbine technology.

TURBINE TYPE. Two types of gas turbines were considered for this project during project design and development, and the following discussion provides some background information on turbine selection that is considered beyond the required scope of the BACT review for the proposed turbines. These two turbine types are: industrial gas turbines, which are heavy-duty designs developed especially for use as mechanical drives; and aeroderivative turbines, which were originally modified from existing aircraft engine models, and whose compact, light-weight design was suited for uses such as propulsion engines or power plants for naval vessels, although they have more recently been adapted for use as mechanical drives. While aeroderivative turbines tend to be lighter and less physically bulky than an industrial gas turbine of comparable power output, both turbine types are available in a range of sizes, providing flexibility in the selection of the appropriate size for a given application.

As noted in a 2013 conference paper by Marybeth Nored and Andrew Brooks, industrial gas turbines are a conventional choice for mechanical drive applications, and are used as the refrigerator compressor drives in well over 90 percent of existing gas turbine-based LNG facilities (mostly in the Frame 5, Frame 7, and Frame 9 size classes).[25] However, aeroderivative designs are beginning to see increased use for LNG projects, and have several efficiency advantages over industrial gas turbines. One chief advantage for aeroderivative designs is a higher efficiency during full load conditions due to higher firing temperatures and compression ratios. A 2007 conference paper by Cyrus B. Meher-Homji *et al.*, discussed the first use of aeroderivative turbines as refrigeration drivers for LNG liquefaction and their performance relative to industrial gas turbines.[26] Figure 5-1 is a plot of thermal efficiency vs. specific work (work output per kg of combustion air) for a large population of aeroderivative and industrial engines.[27] The aeroderivative turbines are shown to achieve higher thermal efficiencies than the industrial

[25] Marybeth Nored and Andrew Brooks, "A Historical Review of Turbomachinery for LNG Applications" (LNG17 Conference, Houston, TX, Paper Mach-10, April 2013), http://www.gastechnology.org/Training/Documents/LNG17-proceedings/Mach-10-Marybeth_Nored.pdf

[26] Cyrus B.Meher-Homji *et al.*, "Aeroderivative Gas Turbine Drivers for the ConocoPhillips Optimized Cascade LNG Process—World's First Application and Future Potential" (LNG15 Conference, Barcelona, Spain, Paper PS2-6, April 2007), http://www.ivt.ntnu.no/ept/fag/tep4215/innhold/LNG%20Conferences/2007/fscommand/PS2_6_Meher_Homji_s.pdf.

[27] Ibid., p. 8.

gas turbines, and Meher-Homji estimates that overall plant thermal efficiency may increase by 3 percent or more, thus reducing total fuel consumption and GHG emissions.

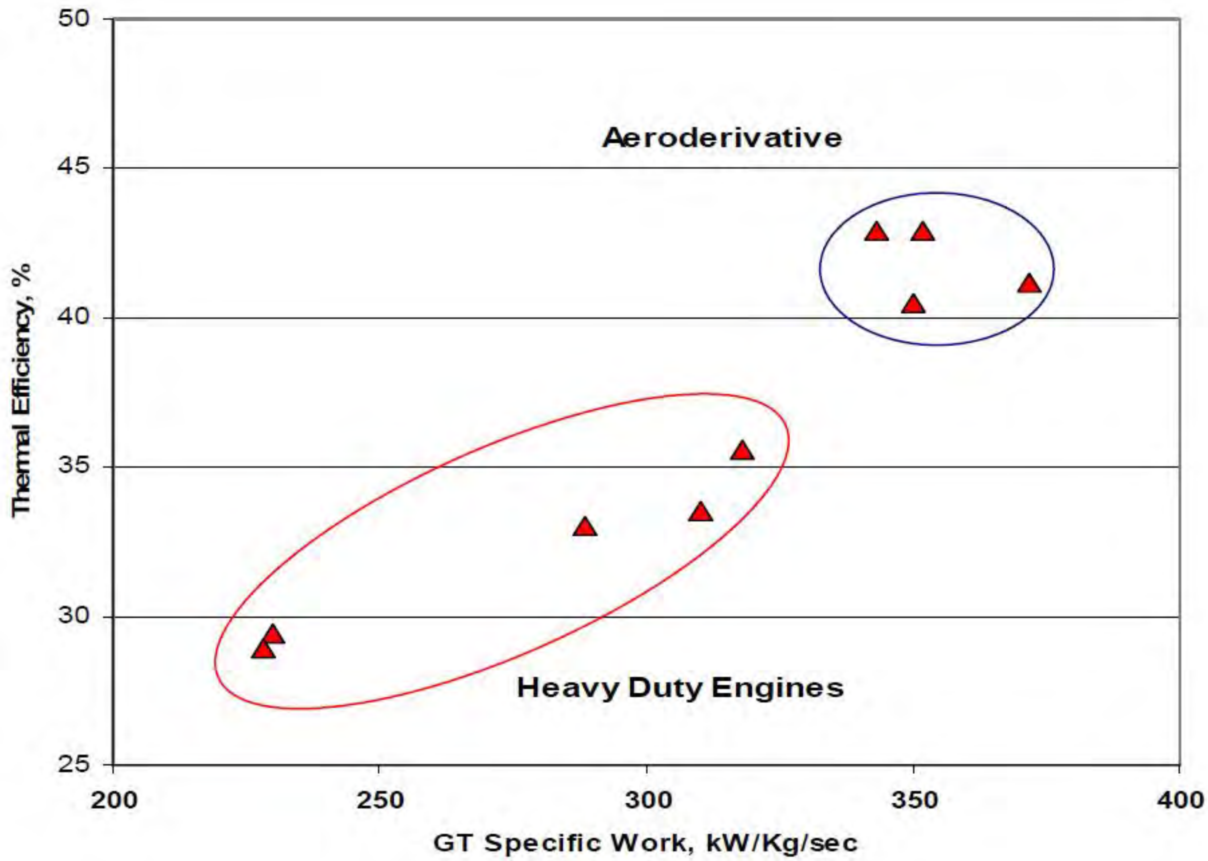


Figure 5-1. **Map of International Organization for Standardization (ISO) Thermal Efficiency vs. Specific Work of Commonly Used Frame Drivers and Aeroderivative Engines**

(From Meher-Homji *et al*., “Aeroderivative Gas Turbine Drivers,” p. 8. The figure compares the performance of Frame 5C, 5D, 7EA, and 9E frame-type drivers with that of GE PGT25+, GE LM6000, Rolls-Royce 6761, and Rolls-Royce Trent aeroderivative units.)

Aeroderivative turbines also benefit from a multi-shaft design, providing an efficiency advantage during part-load scenarios, and speed variation over a wider range of operation. Most industrial gas turbines are single-shaft designs.

Finally, aeroderivative turbines include some operational advantages that make them not only a technically feasible efficiency option for the Project, but a preferable operational option over industrial gas turbines. In summary, aeroderivative turbines offer:

- a greater range of available sizes;
- higher thermal efficiency than industrial gas turbines with a comparable power output, resulting in a significant reduction in GHG emissions (up to 30% reduction);
- variable-speed drivers that aid the flexibility of the process, allowing startup without the use of large VFD starter motors, as are commonly used on single-shaft gas turbines;

- excellent starting torque capacity, allowing large trains to start up under settle-out pressure conditions with no need to depressurize the compressor as is common for single-shaft drivers;
- easier installation due to lighter weight; and
- the possibility of modular maintenance. A full engine change-out can be performed in approximately 24 to 48 hours, resulting in significantly improved plant availability versus the 14 or more days required for a major overhaul of a heavy duty gas turbine.[28]

USE OF WASTE HEAT. Combustion turbines produce hot exhaust gas that can be used to generate additional useful work. A heat recovery steam generator (HRSG) extracts energy from the hot exhaust to boil water. The resulting steam can either be used to drive a steam turbine electric generator, which is referred to as "combined cycle" power generation, or to provide heat for other industrial or commercial processes, which is referred to as "cogeneration." A WHRU can be used to heat a medium other than water, such as mineral oil, which can then be used in place of steam to provide heat for other processes. The technical feasibility of using waste heat is addressed below for each of the Project's three separate turbine groups.

INLET AIR COOLING. Inlet air cooling is a potentially feasible technology that is used primarily to boost gas turbine power output during warm weather, with very modest potential gains in turbine efficiency as a side benefit. A turbine's maximum power output is highest at low outdoor air temperatures, and drops as the temperature increases. For example, the Rolls-Royce Trent 60 model selected for the FLSO refrigerator compressor turbines can only produce 76 percent of its maximum rated output when the ambient air temperature is 41 °C (106 °F), compared to a temperature of 15 °C (59 °F). Higher air temperatures also decrease turbine energy efficiency by a small amount. For example, the Trent 60's Btu/kWh heat rate is about 3 percent higher at 41 °C than at 15 °C.

Cooling the combustion air before it enters the turbine compressor inlet increases power output by increasing the amount of fuel that can be burned. Since the turbine's inlet compressor draws air at a fixed volumetric flow rate (for a given compressor speed), the mass flow rate of air into the turbine varies with temperature, as cold air is more dense than warm air. A greater mass flow of air means more fuel can be burned, increasing total power production. As mentioned, the Btu/kWh heat rate is also modestly improved as a result of restoring the power output lost at higher temperatures, but it cannot be improved beyond the turbine's normal efficiency for a given air inlet temperature.

As discussed in a 2013 conference paper by John L. Forsyth, the two main methods of inlet air cooling available for turbines at LNG facilities are evaporative cooling, and turbine inlet chilling using refrigeration. Evaporative cooling lowers air temperature either by passing the combustion air over a wet surface, or by introducing water mist into the air flow. Evaporative cooling uses relatively little additional power, but works best in arid climates, and is ineffective in the warm humid conditions found on the Texas Gulf Coast.[29] It is therefore not considered a feasible technology for improving the Project's turbine efficiency. Refrigerated inlet chilling works effectively in humid conditions, but requires significantly more power than evaporative cooling, so while it is a technically feasible technology for inlet air cooling, it cancels out much of the efficiency benefit gained by the modest reduction in the turbine's Btu/kWh heat rate. The Project's turbines have been sized to provide sufficient power output at

[28] Ibid., p. 8.
[29] John L. Forsyth, "Gas Turbine Inlet Air Chilling for LNG" (LNG17 Conference, Houston, TX, Paper Mach-4, April 2013), http://www.gastechnology.org/Training/Documents/LNG17-proceedings/Mach-4-John_Forsyth.pdf, p. 9.

all ambient conditions without the use of inlet air cooling, and its use solely for improving energy efficiency is considered to be of relatively negligible benefit.

OPERATING LOAD RANGE. Gas turbines of all types and sizes are most efficient when operated at their maximum rated output. Therefore, a smaller turbine that operates at full load to power a given process may have a lower effective Btu/kWh heat rate (i.e., higher efficiency) than a larger turbine that would spend most of its time operating at part-load to power the same process. Appropriate turbine size selection is a technically feasible option for energy efficiency, and the Project's turbines have been specifically selected so that they may operate at full load to the greatest practical extent.

Energy Efficiency: FLSO Refrigerator Compressor Turbines. Each FLSO will have four refrigerator compressors that will be driven by four natural gas-fired turbines. The production intent is that all four liquefaction trains per FLSO will produce at maximum capacity levels with the exception of periodic shutdowns for scheduled inspections and maintenance. The compressor power requirement of approximately 59 MW is well suited to two potential turbine models that were considered for the Project, the Rolls-Royce Trent 60 WLE, and the General Electric LM6000. While the Rolls-Royce Trent 60 has been selected for this process, both of these aeroderivative gas turbine models have comparable efficiency, and either would be better suited for the Project than an industrial gas turbine. As previously mentioned, aeroderivative engines have higher thermal efficiencies than industrial gas turbines (resulting in lower GHG emission rates), as well as greater process flexibility, more available sizes, and shorter turn-around time for maintenance. The two turbine models considered have comparable heat rates, as shown in Table 5-3.

Table 5-3
Summary of FLSO Refrigerator Compressor Turbine Heat Rates

Equipment Option	Heat Rate (Btu/kWh, HHV)
Rolls-Royce Trent 60 WLE *	9,251
GE LM6000-PG Sprint **	9,515

* Rolls-Royce heat rate is 8,801.6 kJ/kWh on a lower heating value (LHV) basis, for full-load operation at ISO conditions of 59 °F and 60% RH (converted to Btu/kWh, HHV), based on vendor data supplied in "Excelerate Energy, Lavaca Bay, OG2668, Industrial Trent Mechanical Drive, Wet Low Emissions Combustion System." (See Appendix C of this application.)

** GE heat rate is 8,580 Btu/kWh (assumed LHV), for full-load 60 Hz electric generation at ISO conditions of 59 °F and 60% RH (converted to HHV), based on GE Power& Water brochure at: https://www.ge-distributedpower.com /products/power-generation/35-to-65mw/lm6000-sprint-series.

Recovery of waste heat is not a technically feasible option for the FLSO compressor turbines, due to space constraints preventing the installation of the large heat exchangers that would be required.

Energy efficiency: FLSO power generation turbines. The power specifications for each FLSO will require the installation of approximately 60 MW of baseload electric generation (two turbines operating 8,760 hrs/yr) with a third turbine in standby mode and operating during LNG offloading activities (approximately 1,036 hrs/yr). This configuration provides the operational flexibility needed for this Project. This power requirement is very well suited for the General Electric LM2500+G4 aeroderivative gas turbine rated at approximately 33 MW, whose proven track record meets project needs for safety and reliability. The Rolls-Royce RB211 aeroderivative gas turbine was also considered for the Project, but has a less proven track record in similar service. These two aeroderivative gas turbines are comparable efficiency, and either would be better suited for the Project than an industrial gas turbine. Heat rates are comparable for the two turbine models considered, as shown in Table 5-4.

Table 5-4
Summary of FLSO Power Generation Turbine Heat Rates

Equipment Option	Heat Rate (Btu/kWh, HHV)
GE LM2500+G4 *	10,673
Rolls-Royce RB211**	9,618

* GE heat rate is 9,774 kJ/kWh (LHV), for full-load operation at 75 °F and 60% RH (converted to Btu/kWh, HHV), based on vendor data supplied in "Dresser-Rand DR-61G4 SAC Predicted Performance Data," for a single annular combustor (SAC) with water injection for NO_x suppression. (See Appendix C of this application.)

** Rolls-Royce heat rate is approx. 9,150 kJ/kWh (assumed LHV) for full-load operation at 59 °F and 60% RH (converted to Btu/kWh, HHV), based on data for RB211-GT61 DLE genset in Rolls-Royce brochure at: http://www.rolls-royce.com/Images/RB211_gasturbine_tcm92-21095.pdf.

Additionally, each FLSO power generation turbine will have an associated WHRU, which uses excess heat from the exhaust gas to warm a circulating mineral oil bath. This heated oil is used by various processes onboard the FLSO, including the fuel gas heater and the LNG vaporizer. The use of the WHRUs will reduce the need for additional combustion units to warm the mineral oil, thereby reducing GHG emissions.

Energy efficiency: Onshore power generation turbines. Power generation for the onshore facilities, which include the feed gas compressors and the feed gas pretreatment plant, will be provided by seven natural gas-fired, dry low emissions (DLE) GTGs, equipped with (HRSGs) that will power two steam turbines in a combined cycle configuration. Six of the seven GTGs are expected to be in nearly continual use with the seventh GTG in standby mode in case of a failure of a single GTG. Three GTGs per project phase with one shared spare is the preferred modular design for this Project, providing flexibility and redundancy. Each set of gas turbines will have combined rated output of 34.5 MW, for a total of 69 MW when six gas turbines are operating. Steam produced by each set of gas turbines will be sent to a single steam turbine rated at 6 MW (for a total of 12 MW of additional power generation when all six gas turbines operate). This greatly increases the overall efficiency of these turbines by allowing for gross generation of 81 MW versus just 69 MW without the steam turbine component supplied by combine cycle operation. This additional power reduces the need for additional combustion generation, thus reducing GHG emissions.

The gas turbine power requirement is well-matched by two comparably sized potential turbine models, the Siemens SGT-400 (13.4 MW) and the Solar Mars 100 (11.4 MW). The slightly larger Siemens SGT-400 is being proposed for this operation since it can provide the 11.5 MW required to meet the Project's electrical loads even at a high ambient temperature of 30 °C (86 °F). The Siemens SGT-400 has an excellent track record for this type of application, and is better suited for the Project than an industrial gas turbine. As mentioned above, aeroderivative engines have higher thermal efficiencies, resulting in lower GHG emissions. Heat rates are comparable for the two potential turbine models considered, are shown in Table 5-5.

Table 5-5
Summary of Onshore Power Generation Turbine Heat Rates

Equipment Option	Heat Rate (Btu/kWh, HHV)
Siemens SGT-400 *	10,597
Solar Mars 100 **	11,494

* Siemens heat rate is estimated to be 10,082 kJ/kWh (LHV), for full-load operation at 59 °F (converted to Btu/kWh, HHV), based on preliminary data supplied for the Project by Technica in the document "Electrical Scope of Works, 06120600-E-0105-002_R0."

** Solar heat rate is 10,365 Btu/kWh (assumed LHV), for full-load operation at ISO conditions of 59 °F and 60% RH (converted to HHV), based on Solar Turbines performance data brochure at: https://mysolar.cat.com/cda/files /126902/7/ds100pg.pdf.

Carbon capture and storage. Capturing, transporting, and storing the CO_2 in the combution turbine exhaust is a post-combustion GHG control technology that is not considered by ELO Port Lavaca to be commercially viable at this time for this type of application. Use of commercially unviable CCS is also inconsistent with the business objectives of the project, which, as discussed above, are to provide safe, reliable and cost-effective production of LNG for export. However, based on requests by EPA Region 6 for other GHG permit applications, CCS is evaluated further in this analysis.

EPA's GHG permitting guidance provides the following suggestions for evaluating the feasibility of CCS:

> CCS is composed of three main components: CO_2 capture and/or compression, transport, and storage. CCS may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for each of these three main components from what has already been applied to a differing source type. For example, the temperature, pressure, pollutant concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review. Furthermore, CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations (e.g., space for CO_2 capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for sequestration, or other storage options)...While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases.[30]

CAPTURE. With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation.[31] Many of these methods are either still in development or are not suitable for simple cycle turbines. Of the potentially applicable technologies, post-combustion capture with an amine solvent such as monoethanolamine (MEA) is currently the preferred

[30] EPA, *GHG Permitting Guidance*, pp. 35-36.
[31] Meihong Wang, Adekola Lawal, Peter Stephenson, J. Sidders, and C. Ramshaw, "Post-combustion CO_2 capture with chemical absorption: A State-of-the-art Review," *Chemical Engineering Research and Design* 89, Issue 9 (September 2011): 1609-1624, doi:10.1016/j.cherd.2010.11.005.

option because it is the most mature and well-documented technology,[32] and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes.[33] Post-combustion capture using MEA is also the only process known to have been previously demonstrated in practice for gas turbines in a small-scale application.[34]

As identified by the August 2010 Report of the Interagency Task Force on Carbon Capture and Storage, co-chaired by the U.S. Department of Energy (DOE) and EPA, while amine- or ammonia-based CO_2 capture technologies are commercially available, they have been implemented either in non-combustion applications (i.e., separating CO_2 from field natural gas) or on relatively small-scale combustion applications (e.g., slip streams from power plants, with volumes on the order of what would correspond to one megawatt), and:

> Scaling up these existing processes represents a significant technical challenge and potential barrier to widespread commercial deployment in the near term.... It is unclear how transferable the experience with natural gas processing is to separation of power plant flue gases, given the significant differences in the chemical make-up of the two gas streams. In addition, integration of these technologies with the power cycle at generating plants present significant cost and operating issues that will need to be addressed to facility widespread, cost-effective deployment of CO_2 capture.... 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 applications.[35]

Although the Project is not a large electric generating plant like those addressed in the above excerpt from the Interagency Task Force Report , the Project's combustion turbines will collectively have the capacity to generate the equivalent of approximately 400 MW of power, which is comparable to the size of many power plants. Therefore, it is concluded that current CO_2 capture technologies have not been demonstrated in practice at the scale required for the Project.

TRANSPORT. Once CO_2 has been captured, it must be transported to a suitable storage site, which generally requires either construction of a new CO_2 pipeline, or connection to an existing pipeline. Figure 5-2 shows a map of existing and planned CO_2 pipelines in the United States.[36] The nearest existing CO_2 pipeline infrastructure shown is the Green Pipeline operated by Denbury Resources, a company specializing in enhanced oil recovery (EOR) operations using CO_2 injection. The Green Pipeline's western terminus, in Alvin, Texas, is approximately 90 miles from the proposed Project site. According to

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[32] Hanne M. Kvamsdal, Actor Chikukwa, Magne Hillestad, Ali Zakeri, and Aslak Einbu, "A comparison of different parameter correlation models and the validation of an MEA-based absorber model," *Energy Procedia* 4 (2011): 1526-1533, doi:10.1016/j.egypro.2011.02.021.

[33] Intergovernmental Panel on Climate Change (IPCC), "IPCC Special Report on Carbon Dioxide Capture and Storage," prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)] (Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 2005), http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf.

[34] Satish Reddy, Jeff Scherffius, Stefano Freguia, and Christopher Roberts, "Fluor's Econamine FG Plus[SM] Technology: An Enhanced Amine-Based CO_2 Capture Process" (Second National Conference on Carbon Sequestration, National Energy Technology Laboratory, Department of Energy, Alexandria, VA, May 2003), http://netl.doe.gov/publications/proceedings/03/carbon-seq/PDFs/169.pdf.

[35] U.S. Department of Energy (DOE), "Report of the Interagency Task Force on Carbon Capture and Storage" (Washington, DC: DOE Office of Fossil Energy, August 12, 2010), http://energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf, p. 28, p. 50.

[36] DOE, "Interagency Task Force Report," p. B-1.

the Denbury Resources website,[37] this pipeline has been constructed and is currently operating to transport CO_2 used for EOR operations, thus representing the most feasible existing transport option for CCS.

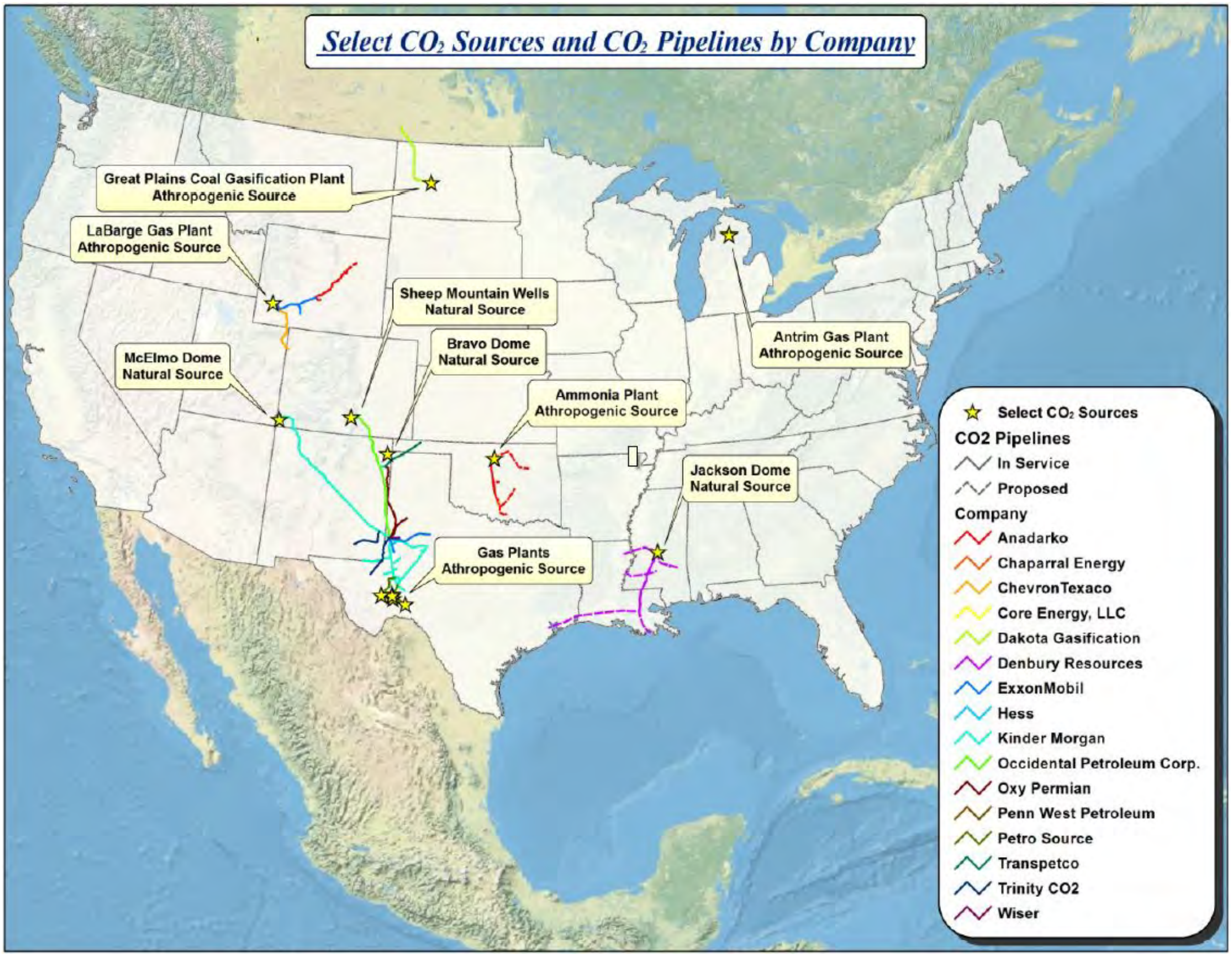

Figure 5-2. Existing and Planned CO_2 Pipelines in the United States with Selected Sources
(From DOE, "Interagency Task Force Report," p. B-1.)

STORAGE. The final component of CCS is long-term storage of the captured CO_2. This can be accomplished by sequestering the CO_2 in suitable geologic formations, such as deep un-minable coal seams, deep saline formations, depleted oil basins, depleted gas fields, or by injecting it into active oil fields employing enhanced oil recovery (EOR).With regard to storage for CCS, the Interagency Task Force concluded that while there is currently estimated to be a large volume of potential storage sites, "to enable widespread, safe, and effective CCS, CO_2 storage should continue to be field-demonstrated for a variety of geologic reservoir classes," and that "scale-up from a limited number of demonstration projects to wide-scale commercial deployment may necessitate the consideration of basin-scale factors (e.g., brine displacement, overlap of pressure fronts, spatial variation in depositional environments, etc.)." [38]

[37] "Denbury Resources - Operations - Gulf Coast Region - CO_2 Sources and Pipelines," Denbury Resources Inc., accessed May 27, 2014, http://www.denbury.com/operations/gulf-coast-region/co2-sources-and-pipelines/default.aspx.
[38] DOE, "Interagency Task Force Report," p. 51.

POTENTIAL NEARBY PROJECT. ELO Port Lavaca has learned that a potential CCS project is currently being evaluated for a site located in the Port of Point Comfort, TX.[39] The project, using a proprietary carbon capture technology called "Stargate™ 250," will be a new 500 MW natural gas-fired power plant with integrated carbon capture for EOR. Sargas Technology and General Electric formed an alliance to provide a gas turbine for the gas-fired plant with integrated carbon capture for EOR. Additionally, Sargas has partnered with Daewoo Shipbuilding & Marine Engineering, and SNC-Lavalin, Inc., to construct and support Stargate™ 250 on a turnkey EPC basis with estimated project startup in 2016. However, detailed information regarding this potential project, such as the technology being employed to capture the carbon for EOR, the project timeframe, et cetera, is not publically available for review to evaluate the technical feasibility of the proposed project. Therefore, this project and proposed technology are not being evaluated as a possibility to determine if CCS would be technically feasible for ELO Port Lavaca.

CONCLUSION. Based on the above-mentioned EPA guidance regarding the overall technical feasibility of the three components of CCS, and the conclusions of the Interagency Task Force regarding the CO_2 capture component (let alone the yet-to-be-demonstrated technical feasibility of long-term storage at commercial scales), and the fact there has been no project either successfully demonstrated or constructed, CCS is not considered technically feasible. However, given the possibility of alternate opinions that CCS is technically feasible and to ensure a complete application, ELO Port Lavaca has conservatively chosen to carry the CCS option forward in the BACT analysis for the combustion turbines as if it were technically feasible.

Good combustion, operating and maintenance practices. Good combustion, operation, and maintenance practices are a technically feasible control option for improving the fuel efficiency of the combustion turbines. Natural gas-fired combustion turbines typically operate in a lean pre-mix mode to ensure effective staging of air/fuel ratios in the turbine; thus, maximizing fuel efficiency and minimizing incomplete combustion. Additionally, these turbines will have a state-of-the-art instrumentation and control system to automatically control the operation of the combustion turbines. This control system will monitor the operation of the units, continuously regulating the fuel flow and turbine operation to achieve optimal high-efficiency performance, thus resulting in lower emissions. Good combustion practices also include proper maintenance and tune-ups of the combustion turbine systems. This will be performed in accordance with the manufacturer's recommendations and specifications.

Step 3: Rank Technically Feasible GHG Control Options by Effectiveness

The ranking of the four options discussed in Step 2 by effectiveness (most effective to least effective) is as follows:

1. CCS (70% CO_2 removal and possibly up to 90%).[40]
2. Low carbon-emitting fuels (GHG emissions from gas are 50% below solid fuels and 30% below liquid fuels on a lb/mmBtu basis).
3. Energy efficiency / Low Heat Rate (10-20% less GHG than older generation combustion turbines).
4. Good combustion, operating and maintenance practices.

[39] "Projects – Sargas Texas," Sargas Texas, accessed May 28, 2014, http://sargastexas.com/projects/.
[40] Gary T. Rochelle, "Amine Scrubbing for CO2 Capture," (unpublished manuscript, Department of Chemical Engineering, University of Texas at Austin, September 15, 2009), http://research.engr.utexas.edu/rochelle/images/stories/publications /Perspective_revised_js_ed_revgtrmed.pdf. Rochelle has identified that "70 to 95% removal probably represents the range where the cost of CO_2 removal ($/ton) is minimized. However, there are few fundamental barriers to greater removal."

Step 4: Evaluate Most Effective GHG Control Options

The Project is proposing to implement low carbon fuel, high efficiency equipment, and good combustion, operating and maintenance practices (items 2, 3, and 4 on the list in Step 3) by employing state-of-the-art, highly efficient, natural gas-fired combustion turbine technology. In this section, CCS is evaluated.

CCS: Economic, energy, and environmental evaluation. Although CCS would reduce CO_2 emissions by possibly more than 70%, there are energy and environmental impacts associated with this technology. According to a June 2010 report by the Government Accountability Office, parasitic load due to the capture and storage of CO_2 emissions is between 21-32%.[41] If the electricity needed to power the CCS system were to be generated by ELO Port Lavaca, the Project's heat rate (efficiency) would be adversely impacted with a potential 21-32% fuel input increase in order to achieve the facility's energy requirements. The CCS energy requirement would most likely require the installation and operation of additional turbines. Due to the fact that there are three different power generation turbine sets for the Project in different areas of the facility, the logistics of installing a carbon capture system would further complicate the process. Likely more significant are the extreme space constraints associated with this site, in particular on the FLSOs. The Interagency Task Force on CCS identified a capture cost of $60 per metric ton for integrated gasification combined-cycle coal-fired power plants, $95 per metric ton for pulverized coal (PC) power plants, and $114 per metric ton for natural gas-fired combined cycle power plants.[42]

In order to transport the CO_2 from ELO Port Lavaca to the nearest potentially viable existing CO_2 pipeline infrastructure, a connector pipeline of more than 90 miles must be constructed. In doing so, it is possible that ecologically sensitive areas would be impacted due to the distances involved. For this reason, CCS has adverse energy and environmental impacts. In addition, the actual length of pipeline needed to cover a linear distance of 90 miles may be significantly longer. A 2007 working paper prepared by Eric Williams, Nora Greenglass, and Rebecca Ryals for Duke University considered two actual potential CCS sites in North Carolina, and calculated that the least-cost pipeline path distances to the nearest existing CO_2 pipeline connection were approximately 1.6 to 1.8 times the linear distances, as shown in Table 5-6.[43] Therefore, it is likely that the least-cost pipeline path distance needed to cover a linear distance of 90 miles is closer to 150 miles.

Table 5-6
Connector Pipeline Distances for Example CCS Sites in North Carolina

	Site 1	Site 2
Linear Distance (approx.)	167 miles	74 miles
Least-Cost Pipeline Path Distance	275 miles	133 miles

From Williams *et al*., "Carbon Capture, Pipeline and Storage," p. 19.

[41] U.S. Government Accountability Office (GAO), "Coal Power Plants: Opportunities Exist for DOE to Provide Better Information on the Maturity of Key Technologies to Reduce Carbon Dioxide Emissions," GAO-10-675 (Washington, DC, June 16, 2010), http://www.gao.gov/new.items/d10675.pdf.
[42] DOE, "Interagency Task Force Report," p. 50.
[43] Eric Williams, Nora Greenglass, and Rebecca Ryals, "Carbon Capture, Pipeline and Storage: A Viable Option for North Carolina Utilities?," (working paper CCPP WP 07-01, Climate Change Policy Partnership, Nicholas Institute for Environmental Policy Solutions, Duke University, Durham, NC, March 8, 2007), http://www.nicholas.duke.edu/cgc/news/carboncapture.pdf, p. 19.

Estimates of capital costs for CO_2 pipelines, in units of dollars per inch-mile (i.e., cost per inch of diameter per mile of length), can vary significantly. The Duke study by Williams *et al.* calculated capital costs based on a 2006 reference that assumed costs equivalent to $44,000-$46,000 per inch-mile— plus multipliers for various crossings—[44] but a 2009 report prepared by ICF International for the Interstate Natural Gas Association of America (INGAA) showed that there was a significant cost spike in 2006-2007 due to higher material and labor costs, and estimated that costs would probably be closer to $75,000 to $90,000 per inch-mile depending on the pipe diameter.[45] (For a 12.75-inch outside diameter, 150-mile long pipeline, the estimated capital cost would be approximately $143.4 million, based on the information in the ICF report.) More recently, Denbury Resources estimated to-date expenditures through 2010 of approximately $884 million, excluding capitalized interest, for its Green Pipeline, which is a 24-inch diameter, 325-mile long CO_2 pipeline.[46] This amounts to approximately $113,000 per inch-mile.

In addition, the capital cost of constructing a pipeline does not include the cost of operating and maintaining a pipeline. The ICF report, which addressed CO_2 pipelines specifically, noted that (a) there are differences between CO_2 and natural gas pipelines (in terms of pipeline design as well as operations—i.e., pressurized CO_2 behaves as a supercritical fluid and must be pumped rather than compressed at booster stations),[47] and that (b) identifying a total cost per ton of CO_2 is highly dependent on pipeline length and diameter, which is in turn dependent on the extent to which other CO_2 sources can be tied into the same pipeline.[48] An example calculation conducted for an idealized case where eight 500 MW power plants use 150 miles of pipeline (including 100 miles of 30-inch-diameter mainline shared by all eight, 25 miles of 16-inch pipeline for each pair, and 25 miles of 12-inch pipeline for each individual power plant) showed a "Total Cost of Service" of $4.61 per metric ton of CO_2 ($4.18 per short ton of CO_2), assuming each plant emits approximately 3.4 million metric tons (3.8 million short tons) of CO_2 per year.For the case of a single power plant with a 12.75-inch pipeline, the ICF report identified a cost of $4.36 per metric ton per 75 miles, which would translate to approximately $8.72/metric ton ($7.91/short ton) for 150 miles (if it is even technically feasible to run pipe this small for this distance).[49]

Storage is a separate cost, although generally not believed to be significant compared to the costs of capture (including initial compression) and transportation (pipeline) assuming that demands continue to exist for use of CO_2 in EOR. Not considering storage costs, the cost to capture and transport CO_2 from the Project would total approximately $123/metric ton, which includes $114/metric ton for up to 3,622,000 metric tons of CO_2 captured ($413 million/year) plus a pipeline service cost of $8.72/metric ton ($31.6 million/year). CCS is clearly economically infeasible for the Project, as anticipated by EPA in its March 2011 GHG permitting guidance, with annual capture and transport costs approaching $450 million/year.

Separately, there are energy and environmental impacts associated with having to separate, compress, and pump the CO_2 over a distance of 150 miles. We have not quantified these here in part because of the complexity in doing so (i.e., impacts are dependent on what route the pipeline would take, if it is even

[44] Williams *et al*., "Carbon Capture, Pipeline and Storage," p. 27.
[45] ICF International, "Developing a Pipeline Infrastructure for CO_2 Capture and Storage: Issues and Challenges" (Prepared for the INGAA Foundation, Washington, DC, February 2009), http://www.ingaa.org/Foundation/Foundation-Reports/Studies/7626/8230.aspx, p. 42.
[46] Denbury Resources Inc., "2010 Annual Report" (March 2011), http://www.denbury.com/files/doc_financials/2010/Denbury_2010_AR.pdf.
[47] ICF International, "Developing a Pipeline Infrastructure for CO_2 Capture and Storage," p. 40.
[48] Ibid., p. 41.
[49] Ibid., p. 42.

technically feasible to install the pipeline) and in part because CCS is clearly economically infeasible for this facility.

Step 5: Select GHG BACT

The very low heat rates associated with modern aeroderivative combustion turbine technology, along with the application of good combustion, operating and maintenance practices selected for the Project, and the use of natural gas fuel, without further control via CCS, constitute BACT for this project. Additionally, for the onshore power plant, the turbines will be matched with steam turbines in a combined cycle configuration, and for the FLSO power generation turbines, exhaust heat recovery will be used to heat mineral oil used for various FLSO processes. In order to ensure that the turbines will operate in an energy efficient manner, ELO Port Lavaca is proposing two types of GHG emission limits. First, ELO Port Lavaca proposes mass emission limits in tons per year of GHGs on a 12-month rolling average basis. Second, ELO Port Lavaca proposes an output-based BACT emission rate in lbs of CO_2 per megawatt hour (lbs CO_2/MWh) for the turbines. The output-based BACT emission rate is based on CO_2 emissions only, given that CO_2 emissions from the turbine exhaust comprise more than 99% of the total GHG emissions from the turbine.

In addition, compliance with the output-based turbine emission limit will be affected by system degradation over time, compliance margin, and varying ambient temperature and electrical demand. EPA Region 1 states in the Fact Sheet for the Pioneer Valley Energy Center (PVEC), Permit Number 052-042-MA14:

> EPA expects a decrease in efficiency of 2.5% over time can be expected even for a well-operated turbine. In its March 9, 2011 application supplement, PVEC claimed a performance margin of 6%. EPA understands the performance margin addresses factors affecting the efficiency which cannot be controlled by PVEC such as ambient temperature. The actual effect of temperature on a combined cycle turbine will vary depending on the turbine's design. The variation can be as much as 10%. Based on the information PVEC provided and on EPA's own research regarding unavoidable decreases in efficiency and variability of performance under a reasonable range of conditions, EPA has determined that BACT is met by an emissions limit that is 8.5% higher than the corrected value which must be met during the initial test.[50]

More recently, EPA Region 6 used the same 8.5% margin in their most recent BACT determination for combustion turbines. This GHG BACT determination was completed in May 2014 for the simple cycle turbines at the Indeck Wharton Energy Center. Consequently, the proposed output-based turbine CO_2 emission limit is 8.5% higher than vendor's ISO-corrected, initial CO_2 emission estimates. The proposed turbine emission limits are shown in Tables 5-7, 5-8, and 5-9 for the FLSO refrigerator compressor turbines, FLSO power generation turbines, and onshore power generation turbines, respectively. For all FLSO turbines, the annual tpy and output-based emission limits are per turbine, but for the onshore power turbines, they are for the combined total of all turbines because the onshore power plant is in a combined cycle configuration with six operating gas turbines sharing two steam generators.

ELO Port Lavaca will demonstrate compliance with these emission limits by monitoring fuel consumption and performing calculations consistent with those presented in Appendix B of the

[50] U.S. Environmental Protection Agency (EPA), "Fact Sheet: Pioneer Valley Energy Center" (Boston, MA: EPA New England, Region 1, Office of Ecosystem Protection, December 2011), http://www.epa.gov/region1/communities/pdf/PioneerValley/FactSheet.pdf.

application. These calculations will be performed on a monthly basis to ensure that the annual rolling average CO_2e emission rate does not exceed this limit.

Table 5-7
FLSO Refrigerator Compressor Turbine (Rolls-Royce Trent 60)
Proposed GHG Emission Limits

Emission Unit	GHG Mass Basis			BACT Emission Limits	
	GHG Potential Emissions[2,3] (tpy)			Output-based CO_2 Emission Rate[1,4]	Annual GHG Emission Limit[2,3] (tpy CO_2e)
NFLSOCT1-4 & SFLSOCT1-4 (Each turbine)	CO_2	273,930	CO_2	1,158 lb CO_2/MWh (gross)	274,729
	CH_4	25.8	CH_4		
	N_2O	0.52	N_2O		

[1] Compliance with the output-based emission limits is based on a 12-month rolling average.

[2] Compliance with the annual emission limits (tpy) is based on a 12-month rolling average.

[3] Includes facility emissions during normal operations as well as startups & shutdowns.

[4] Based on a gross output of 516,849 MW-hr at the 100% load, 15°C ambient case from Rolls-Royce. Initial performance stack testing will be corrected to ISO 3977-2 standard conditions at 59°F, 14.7 psia, and 60 % humidity. On-going limit includes an 8.5% increase over the initial corrected values to account for system degradation over time, compliance margin, and varying ambient and electrical demand.

Table 5-8
FLSO Power Generation Turbine (GE LM2500+G4)
Proposed GHG Emission Limits

Emission Unit	GHG Mass Basis			BACT Emission Limits	
	GHG Potential Emissions[2] (tpy)			Output-based CO_2 Emission Rate[1,3]	Annual GHG Emission Limit[2] (tpy CO_2e)
NFLSOPT1-3 & SFLSOPT1-3 (Each turbine)	CO_2	173,124	CO_2	1,202 lb CO_2/MWh (gross)	173,476
	CH_4	10.2	CH_4		
	N_2O	0.33	N_2O		

[1] Compliance with the output-based emission limits is based on a 12-month rolling average.

[2] Compliance with the annual emission limits (tpy) is based on a 12-month rolling average.

[3] Based on a gross output of 314,817 MW-hr at the 100% load, 4.4°C ambient case from Dresser Rand. Initial performance stack testing will be corrected to ISO 3977-2 standard conditions at 59°F, 14.7 psia, and 60% humidity. On-going limit includes an 8.5% increase over the initial corrected values to account for system degradation over time, compliance margin, and varying ambient and electrical demand.

Table 5-9
Onshore Power Generation Turbine (Siemens SGT-400)
Proposed GHG Emission Limits (Total for All Turbines)

Emission Unit	GHG Mass Basis			BACT Emission Limits	
	GHG Potential Emissions[2] (tpy)			Output-based CO_2 Emission Rate[1,3]	Annual GHG Emission Limit[2] (tpy CO_2e)
OSPT1-7 (Total for all turbines)	CO_2	437,864	CO_2	1,222 lb CO_2/MWh (gross)	438,316
	CH_4	8.3	CH_4		
	N_2O	0.83	N_2O		

[1] Compliance with the output-based emission limits is based on a 12-month rolling average.

[2] Compliance with the annual emission limits (tpy) is based on a 12-month rolling average.

[3] Based on a gross generator output of 783,406 MW-hr at the 100% load (678,286 MW-hr from the gas turbines and 105,120 MW-hr from the steam turbines), 15°C ambient case for Siemens data provided by Technica. Initial performance stack testing will be corrected to ISO 3977-2 standard conditions at 59°F, 14.7 psia, and 60 % humidity. On-going limit includes an 8.5% increase over the initial corrected values to account for system degradation over time, compliance margin, and varying ambient and electrical demand.

5.3 Generator Engines and Firewater Pump Engines

Diesel fired emergency generators and firewater pump engines will be utilized for this project. GHG emissions resulting from the operation of these units will be CO_2, CH_4 and N_2O. The following are the emergency generators powered by engines and fire pump engines proposed for this project:

- A total of four essential 5.5 MW engine driven generator sets will be installed on the FLSO's for start-up, black-start, and GTG service failure during offloading operations. Each essential generator engine will be limited to 720 hours of operation per year.
- A total of four 2,500 hp diesel engine driven fire pumps will be installed on the FLSOs with one additional diesel engine driven fire pump for the onshore facilities. Each fire pump engine will be limited to 52 hours of operation per year.
- A total of two diesel turbo-charged 1.4 MW engine driven emergency generators will be installed on the FLSOs and a total of two diesel 3 MW engine driven emergency generators will be installed for the onshore facilities. The emergency generators on the FLSOs will provide emergency lighting and battery charging capabilities in a power failure scenario in which no power can be provided by the GTGs or the essential generators. These generator engines will be limited to 52 hours of operation per year. The emergency generator engines for the onshore facilities will provide emergency power and power for a black start of the facility and will be limited to 100 hours of operation per year.

Step 1: Identify Potentially Feasible GHG Control Options

Step 1 of the BACT analysis is to identify all feasible control technologies. Carbon capture and storage is not considered to be a feasible control option for the emergency equipment for the same reasons discussed in Section 5.2 for the combustion turbines. Additionally, all Port Lavaca emergency equipment operates on an infrequent basis as noted above and requires immediate availability during plant emergencies. Installing carbon capture controls would require startup of this process prior to the startup of the emergency equipment eliminating the immediate availability of the emergency equipment. Since there are no GHG add-on control technologies available, the following control strategies for this BACT were identified for the diesel emergency generator and firewater pump engines:

- Fuel selection;
- Good combustion, operating and maintenance practices; and
- Efficient engine design.

Step 2: Eliminate Technically Infeasible Options

This step of the process eliminates any control technology that is not considered technically feasible unless it is both available and applicable. Comparing natural gas to diesel fuel, natural gas fueled engines generate lower GHG emissions than diesel fuel; however, it is not considered technically feasible since the engines will need to operate during emergency situations when natural gas supplies may be interrupted.

Instituting good operating and maintenance practices for the emergency generator engines and firewater pump engines will assist in maintaining the combustion efficiency for the equipment. Additionally, ELO Port Lavaca will be installing new emergency generators and firewater pump engines which will be designed with optimal combustion efficiency.

Step 3: Rank Technically Feasible GHG Control Options by Effectiveness

The ranking of the options discussed in Section 5.3.2 by effectiveness (most effective to least effective) is as follows:

- Efficient design; and
- Good combustion, operating and maintenance practices.

Step 4: Evaluate Most Effective GHG Control Options

ELO Port Lavaca will install all new engines for this Project. These will be designed for optimal combustion efficiency. In addition, good combustion, operating, and maintenance practices will be implemented for this equipment. Therefore, neither option is evaluated further in this step.

Step 5: Select GHG BACT

GHG BACT for these emergency generator engines and firewater pump engines is selecting fuel efficient engines and maintaining the engines to operate efficiently and minimizing their hours of operation. The operation of all engines will be limited to the annual hours as described above. GHG BACT limits will be the annual emissions of CO_2e in tons per year based on a 12-month rolling average as follows:

- Essential Generator Engines (NESGEN1, NESGEN2, SESGEN1, SESGEN2) – 2,776 tons CO_2e per year each engine
- FLSO Emergency Generator Engines (NFLSOEGN, SFLSOEGN) – 49 tons CO_2e per year each engine
- FLSO Fire Pump Engines (NFLSOFP1, NFLSOFP2, SFLSOFP1, SFLSOFP2) – 75 tons CO_2e per year each engine
- Onshore Emergency Generator Engines (OSEGN1, OSEGN2) – 254 tons CO_2e per year each engine
- Onshore Fire Pump Engine (OSFP) – 6 tons CO_2e per year

5.4 Boilers and Heaters

Steam Boilers – Amine Regeneration: The amine system units installed as part of the onshore pretreatment operations are used to remove CO_2 and H_2S from the feed gas to satisfy the gas specifications for the liquefaction system. The rich amine solution containing dissolved CO_2 and H_2S is regenerated within the amine stripper column where the CO_2 and H_2S gases are driven off by direct heating with steam flowing upwards from the bottom of the column. Two 215 MMBtu/hr gas-fired boilers are used to generate steam for the amine treatment system.

Regeneration Gas Heaters: A dehydration system downstream of the amine system will used to remove any remaining residual water content in the gas stream prior to processing in the liquefaction process. The dehydration system will utilize a molecular sieve absorbent to remove water from the gas stream and the absorbent will be regenerated using a 47.6 MMBtu/hr gas heater. Two regeneration gas heaters will be installed for this process at Port Lavaca.

Step 1: Identify Potentially Feasible GHG Control Options

In Step 1, of the BACT analysis is to identify all feasible control technologies. The following technologies were identified as potential control options for steam boilers and regeneration gas heaters:

- Carbon capture and storage;
- Fuel selection;
- Good combustion, operating and maintenance practices; and
- Design energy efficiency.

Step 2: Eliminate Technically Infeasible Options

This step of the process eliminates any control technology that is not considered technically feasible unless it is both available and applicable. As previously discussed in Section 5.2 for the combustion turbines, CCS is also considered technically infeasible for control of CO_2 from the boilers due to the dependency on a continuous CO_2 laden exhaust stream and the fact that CCS has not been tested or demonstrated for such small combustion sources. The remaining options are considered technically feasible.

Step 3: Rank Technically Feasible GHG Control Options by Effectiveness

CCS has been eliminated as a control option for the steam boilers and regeneration heaters, thus using natural gas as fuel, implementing good operating and maintenance practices, and installing energy efficient boilers and heaters are the technically feasible control options. ELO Port Lavaca plans to implement these three control options; therefore, ranking them is not necessary for this analysis.

Step 4: Evaluate Most Effective GHG Control Options

Since all of the technically feasible options are being proposed for these steam boilers and regeneration heaters, an evaluation of the most effective control option is not necessary for this analysis.

Step 5: Select GHG BACT

GHG BACT for the steam boilers and regenerator heaters is using natural gas as the fuel source, selecting energy efficient equipment, and maintaining the boilers and heaters to operate efficiently. GHG BACT for the boilers and heaters is 117 lb CO_2e/MMBtu (HHV) heat input for each boiler and heater. In addition, GHG BACT limits will be the annual emissions of CO_2e in tons per year based on a 12-month rolling average as follows:

- Onshore Steam Boilers (OSSTBLR1, OSSTBLR2) – 110,628 tons CO_2e per year each boiler
- Onshore Regeneration Gas Heaters (OSRGH1, OSRGH2) – 24,413 tons CO_2e per year each heater

5.5 Thermal Oxidizer – Amine Regeneration

An amine system will be installed as part of the onshore facilities to remove the entrained carbon dioxide and hydrogen sulfide from the feed gas prior to flowing to the liquefaction process. The removal of the CO_2 is necessary to prevent CO_2 freezing problems in the liquefaction process and the H_2S removal is necessary to meet LNG sulfur specifications. Two thermal oxidizers will be installed to treat the vent gas from the amine system.

Step 1: Identify Potentially Feasible GHG Control Options

In Step 1, of the BACT analysis is to identify all feasible control technologies. The following technologies were identified as potential control options for thermal oxidizers:

- Carbon capture and storage;
- Fuel selection;
- Good combustion, operating and maintenance practices; and
- Thermal oxidizer design.

Step 2: Eliminate Technically Infeasible Options

This step of the process eliminates any control technology that is not considered technically feasible unless it is both available and applicable. As previously discussed in Section 5.2 for the combustion turbines, CCS is also considered technically infeasible for control of CO_2 from the thermal oxidizers due to the dependency on a continuous CO_2 laden exhaust stream and the fact that CCS has not been tested or demonstrated for such sources. The remaining options are considered technically feasible.

Step 3: Rank Technically Feasible GHG Control Options by Effectiveness

The ranking of the three technically feasible options discussed in Section 5.5.2 is not necessary for this analysis since ELO Port Lavaca plans to implement each of them by using natural gas as the fuel source, establishing and using good operating and maintenance practices, and installing properly designed thermal oxidizers which include flow measurement and monitoring of the gas heating values.

Step 4: Evaluate Most Effective GHG Control Options

Since all of the technically feasible options are being proposed for the thermal oxidizers, an evaluation of the most effective control option is not necessary for this analysis.

Step 5: Select GHG BACT

GHG BACT for the thermal oxidizers is using natural gas as the fuel source, installing properly designed thermal oxidizers, and maintaining the units to operate efficiently. ELO Port Lavaca will operate and maintain the thermal oxidizers in accordance with vendor recommended operating and maintenance procedures. ELO Port Lavaca will also perform preventive maintenance checks of oxygen control analyzers and fuel flow meters and will perform tune-ups of the oxidizers on an annual basis or more frequently if recommended by the manufacturer. Good combustion practices will include good air/fuel mixing in the combustion zone, good burner maintenance and operation, and allowing sufficient residence time to achieve resultant VOC emissions in accordance with TCEQ suggested BACT rates for thermal oxidizers, not to exceed 10 ppmvd VOC at 3% O_2. Resultant CO_2e emissions will be maintained within the limit of 256,994 tons CO_2e per year per thermal oxidizer (OSTO1, OSTO2) on a 12-month rolling average basis.

5.6 Flares

Flares will be installed on the FLSOs, and at the onshore pretreatment facility, to control releases resulting from blow down activities during maintenance activities. Each FLSO will be equipped with a high-pressure cold flare and warm flare, each with a continuous pilot, to destroy hydrocarbons from cryogenic and non-cryogenic and service respectively. A low-pressure tank relief and maintenance flare will be installed on each FLSO to handle gases produced during FLSO LNG tank inspections, and LNGC gas-in and cooldown operations. A ground flare system will be installed at the onshore facilities to control emissions from controlled depressurization of pretreatment equipment prior to maintenance.

Step 1: Identify Potentially Feasible GHG Control Options

The following technologies were identified as potential control options for flare emissions:

- Carbon capture and storage;
- Flare gas recovery;
- Good flare design; and
- Use of clean fuels for pilot burners.

Step 2: Eliminate Technically Infeasible Options

This step of the process eliminates any control technology that is not considered technically feasible unless it is both available and applicable. Carbon capture and storage is not considered to be a feasible control option for the flares since there is no ability to collect the exhaust gases from the flare, and capture of the gas streams prior to combustion on an intermittent basis has not been proven. To the extent possible, the FLSOs will recover the gases produced by various processes, by returning them to the liquefaction process, or by using them as as fuel. The flares will therefore only burn gases that cannot be re-used, or that exceed the FLSO's current process capacity or fuel demand. The onshore ground flare will only be used for maintenance depressurization of the pretreatment facility, which will otherwise generally not produce any combustible waste gases that could be recovered. The use of good flare design with appropriate instrumentation and control, and clean fuel for pilot burners, are both feasible control options.

Step 3: Rank Technically Feasible GHG Control Options by Effectiveness

Since all remaining technically feasible control options will be incorporated into the facility design, no ranking of options was performed.

Step 4: Evaluate Most Effective GHG Control Options

Since all remaining technically feasible options are being proposed for the flares, an evaluation of the most effective control option is not necessary for this analysis.

Step 5: Select GHG BACT

GHG BACT for the flares includes the recovery and re-use of process gases to the extent possible, the use of a good flare design with appropriate instrumentation and controls, and natural gas fuel for the pilot burners. Good flare design and operation meeting the requirements of 40 CFR 60.18 and TCEQ BACT guidelines for flares will be implemented to minimize emissions. Good flare design includes pilot flame monitoring, flow measurement, and monitoring of the waste gas heating value. Flow rate and gas composition analyzers will be used to continuously monitor the gas streams sent to the flares. In addition, GHG BACT limits will be the annual emissions of CO_2e in tons per year based on a 12-month rolling average as follows:

- FLSO Cold Flares (NFLSOCF, SFLSOCF) – 6,092 tons CO_2e per year for each flare
- FLSO Warm Flares (NFLSOWF, SFLSOWF) – 6,072 tons CO_2e per year for each flare

- FLSO Tank Relief and Maintenance Flares – 23,522 tons CO_2e per year for both FLSOs combined
- Onshore Ground Flare (OSGF) – 234 tons CO_2e per year

5.7 Tank Maintenance Cold Vents

Each FLSO will be equipped with one dedicated low-pressure tank maintenance cold vent. This vent will receive gases produced by activities related to FLSO LNG tank inspections, or gas-in and cooldown activities for arriving LNGCs, that do not have a sufficient heating value to be flared.

Step 1: Identify Potentially Feasible GHG Control Options

Because of the specialized nature of the LNG tank inspection and LNGC gas-in and cooldown activities, options to control GHG emissions are limited. Gases sent to the tank maintenance cold vent will contain less than 5 percent methane by volume, and will consist of varying mixtures of LNG vapor, inert gas containing up to 14 percent CO_2 by volume, dry air, and damp atmospheric air. Potentially feasible options include:

- Carbon capture and storage;
- Minimizing the volumes of exhaust gas created; and
- Exhaust gas recovery.

Step 2: Eliminate Technically Infeasible Options

Carbon capture and storage is not a technically feasible option, for the reasons discussed in Section 5.6 above.

Minimizing the volumes of exhaust gas created is a feasible option, which can be accomplished by carefully controlling how replacement gases are transferred into the tanks during tank inspection, gas-in, and cooldown activities. See Sections 3.1.9 and 3.1.10 of this application for a description of the "piston effect," which serves to minimize exhaust gas volumes.

Certain exhaust gases can be recovered and re-used as fuel in the FLSO combustion turbines, or vented to another LNG storage tank, and exhaust gas recovery will be used to the extent possible. However, gases sent to the tank maintenance cold vent cannot be recovered in this way, as their composition is not suitable for re-use.

(It should also be noted that use of the tank relief and maintenance flare, instead of the tank maintenance cold vent, will serve to reduce GHG emissions, by converting methane to CO_2, and thus reducing its GWP by a factor of 25. Gases will be flared instead of vented whenever they contain at least 5 percent methane by volume.)

Step 3: Rank Technically Feasible GHG Control Options by Effectiveness

Since all remaining technically feasible control options will be incorporated into the facility design, no ranking of options was performed.

Step 4: Evaluate Most Effective GHG Control Options

Since all remaining technically feasible options are being proposed for the tank maintenance cold vents, an evaluation of the most effective control option is not necessary for this analysis.

Step 5: Select GHG BACT

GHG BACT for the tank maintenance cold vents is proposed to include minimizing the volumes of exhaust gas created; exhaust gas recovery to the extent possible; and use of the tank relief and maintenance flare whenever exhaust gases contain at least 5 percent methane by volume. In addition, GHG BACT will include an annual facility-wide emissions limit of 1,405 tons of CO_2e per year for both tank maintenance cold vents combined, based on a 12-month rolling average.

5.8 Fugitives

The BACT evaluation of fugitive GHG emissions from on-site gas piping and associated equipment is presented in this section. Fugitive components for the proposed project consist of valves, flanges, pressure relief valves, pump seals, compressor seals, and sampling connections. Fugitive GHG emissions from leaking pipe components for the proposed project will consist of CH_4 and CO_2. The ratio of CO_2 to CH_4 in pipeline-quality natural gas is relatively low. Typically the CO_2 content of the gas is estimated to range up to 3.5 weight percent and the CH_4 concentration is estimated to averages 93 weight percent. For purposes of the GHG calculations, it was assumed all piping components are in a rich CH_4 stream.

Step 1: Identify Potentially Feasible GHG Control Options

In Step 1, of the BACT analysis is to identify all feasible control technologies. The following technologies were identified as potential control options for fugitive emissions:

- Installing leakless/sealless technology components to eliminate fugitive emission sources;
- Implementation of a LDAR program in accordance with state and federal air regulations;
- Implementation of alternative monitoring using a remote sensing technology such as infrared cameras;
- Implementation of AVO leak detection program; and
- Designing and constructing facilities with high quality components and materials of construction compatible with the process. Welded piping joints.

Step 2: Eliminate Technically Infeasible Options

This step of the process eliminates any control technology that is not considered technically feasible unless it is both available and applicable.

Leakless technology components are available and currently in use at operating facilities producing highly toxic and hazardous materials. These technologies are generally considered cost prohibitive except for specialized service. Some leakless technologies, such as bellows valves, if they fail, cannot be repaired without a unit shutdown that often generates additional emissions. Therefore, installing leakless technology components would not be considered feasible to install for control of GHG fugitive emissions and is eliminated from any further BACT analysis.

LDAR programs have been developed mainly for the control of VOC emissions. Typical elements of an LDAR program consist of identifying the components to be included in the program, perform routine instrument monitoring of the components, repairing any leaking components and reporting the monitoring results. BACT determinations related to control of VOC emissions rely on technical feasibility, economic reasonableness, reduction of potential environmental impacts, and regulatory requirements for these instrumented programs. Monitoring direct emissions of CO_2 is not feasible with the normally used instrumentation for fugitive emissions monitoring. However, instrumented monitoring is technically feasible for components in CH_4 service.

Alternate monitoring programs such as remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbons.

Leaking fugitive components can be identified through AVO methods. The fuel gases and process fluids in this Project's piping components are expected to have discernible odor, making them detectable by olfactory means. A large leak can be detected by sound (audio) and sight. The visual detection can be a direct viewing of leaking gases, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. AVO programs are common and in place in industry.

A key element in the control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. For example, a valve that has been manufactured under high quality conditions can be expected to have lower runout on the valve stem, and the valve stem is typically polished to a smoother surface. Additionally, welded flanges will be incorporated where practical to eliminate leaking through these joints. All of these factors greatly reduce the likelihood of leaking.

Step 3: Rank Technically Feasible GHG Control Options by Effectiveness

Instrument monitoring within an LDAR program is effective for identifying leaking CH_4, but may be wholly ineffective for finding leaks of CO_2. With CH_4 having a global warming potential greater than CO_2, and the CO_2 present in the gas stream with CH_4, instrument monitoring of the fuel and feed systems for CH_4 would be an effective method for control of GHG emissions. Quarterly instrumented monitoring with a leak definition of 500 ppmv, accompanied by intense directed maintenance, is generally assigned a control effectiveness of 97%.

Remote sensing using infrared imaging has proven effective for identification of leaks including CO_2. The process has been the subject of EPA rulemaking as an alternative monitoring method to the EPA's Method 21. Effectiveness is likely comparable to EPA Method 21 when cost is included in the consideration.

Audio/Visual/Olfactory means of identifying leaks owes its effectiveness to the frequency of observation opportunities. Those opportunities arise as operating technicians make rounds, inspecting equipment during those routine tours of the operating areas. This method cannot generally identify leaks at as low a leak rate as instrumented reading can identify; however, low leak rates have lower potential impacts than do larger leaks. This method, due to frequency of observation is effective for identification of larger leaks.

Use of high quality components is effective in preventing emissions of GHGs, relative to use of lower quality components, as well as welding flange joints where practicable.

Step 4: Evaluate Most Effective GHG Control Options

The TCEQ has published BACT guidelines for fugitive emissions and has provided BACT recommendations for uncontrolled fugitive emission rates.[51] Based on the current BACT requirements

[51] Texas Commission on Environmental Quality (TCEQ), "Current Best Available Control Technology (BACT) Requirements: Equipment Leak Fugitives" (August 2011), https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_fugitives.pdf.

there are no minimum acceptable control technology for uncontrolled VOC equipment leak fugitive emissions less than 10 tons per year. Based on the emission calculations for fugitive emissions, the annual VOC emissions for the Project have been calculated to be less than 10 tons per year and thus "no controls" is considered BACT. However, ELO Port Lavaca is proposing to implement an effective control option consisting of an instrumented monitoring program as implemented through the TCEQ 28MID LDAR program. This is considered the top control case as BACT, having control efficiencies of 97%. Additionally, an AVO program to monitor for leaks for the time periods between instrumented checks will be implemented to provide additional control efficiencies. The proposed project will also utilize high quality components and materials of construction, including gasketing, that are compatible with the service in which they are employed. Since ELO Port Lavaca is implementing the most effective control options available, additional analysis is not necessary.

Step 5: Select GHG BACT

ELO Port Lavaca is proposing to implement the 28MID LDAR program as BACT for the control of fugitive GHG emissions from piping components. The 28MID LDAR program is one of TCEQ’s most stringent LDAR program for detecting any leaks and making repairs as soon as practicable. In addition, to the LDAR program ELO Port Lavaca will be implementing an AVO program for time periods between LDAR checks providing additional control efficiencies. Therefore it is estimated that the overall control efficiency for fugitive GHG emission would be approximately 97%. While no tpy emission limits are proposed for fugitive GHG, combined fugitive emissions from the two FLSOs are estimated to be 0.0 tpy for CO_2, 5.8 tpy for CH_4, and 145.0 tpy for CO_2e, when using the control efficiencies for 28MID AVO. For onshore fugitives, potential emissions are estimated to be 0.16 tpy for CO_2, 4.3 tpy for CH_4, and 106.7 tpy for CO_2e, when using the control efficiencies for 28MID AVO.

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APPENDIX A
TCEQ Application Tables

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	6/5/2014	Permit No.:	TBD	Regulated Entity No.:	107273930
Area Name:	Lavaca Bay LNG Project			Customer Reference No.:	604576488

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND	(B) TPY
NFLSOCT1	NFLSOCT1	North FLSO Compressor Turbine 1	Carbon Dioxide (CO2)	N/A	273,930
		[includes 0.1 tpy CH4 (2.5 tpy CO2e) from SUSD]	Methane (CH4)	N/A	25.9
			Nitrous Oxide (N2O)	N/A	0.52
			Carbon Dioxide Equivalents (CO2e)	N/A	274,732
NFLSOCT2	NFLSOCT2	North FLSO Compressor Turbine 2	Carbon Dioxide (CO2)	N/A	273,930
		[includes 0.1 tpy CH4 (2.5 tpy CO2e) from SUSD]	Methane (CH4)	N/A	25.9
			Nitrous Oxide (N2O)	N/A	0.52
			Carbon Dioxide Equivalents (CO2e)	N/A	274,732
NFLSOCT3	NFLSOCT3	North FLSO Compressor Turbine 3	Carbon Dioxide (CO2)	N/A	273,930
		[includes 0.1 tpy CH4 (2.5 tpy CO2e) from SUSD]	Methane (CH4)	N/A	25.9
			Nitrous Oxide (N2O)	N/A	0.52
			Carbon Dioxide Equivalents (CO2e)	N/A	274,732
NFLSOCT4	NFLSOCT4	North FLSO Compressor Turbine 4	Carbon Dioxide (CO2)	N/A	273,930
		[includes 0.1 tpy CH4 (2.5 tpy CO2e) from SUSD]	Methane (CH4)	N/A	25.9
			Nitrous Oxide (N2O)	N/A	0.52
			Carbon Dioxide Equivalents (CO2e)	N/A	274,732
SFLSOCT1	SFLSOCT1	South FLSO Compressor Turbine 1	Carbon Dioxide (CO2)	N/A	273,930
		[includes 0.1 tpy CH4 (2.5 tpy CO2e) from SUSD]	Methane (CH4)	N/A	25.9
			Nitrous Oxide (N2O)	N/A	0.52
			Carbon Dioxide Equivalents (CO2e)	N/A	274,732
SFLSOCT2	SFLSOCT2	South FLSO Compressor Turbine 2	Carbon Dioxide (CO2)	N/A	273,930
		[includes 0.1 tpy CH4 (2.5 tpy CO2e) from SUSD]	Methane (CH4)	N/A	25.9
			Nitrous Oxide (N2O)	N/A	0.52
			Carbon Dioxide Equivalents (CO2e)	N/A	274,732
SFLSOCT3	SFLSOCT3	South FLSO Compressor Turbine 3	Carbon Dioxide (CO2)	N/A	273,930
		[includes 0.1 tpy CH4 (2.5 tpy CO2e) from SUSD]	Methane (CH4)	N/A	25.9
			Nitrous Oxide (N2O)	N/A	0.52
			Carbon Dioxide Equivalents (CO2e)	N/A	274,732
SFLSOCT4	SFLSOCT4	South FLSO Compressor Turbine 4	Carbon Dioxide (CO2)	N/A	273,930
		[includes 0.1 tpy CH4 (2.5 tpy CO2e) from SUSD]	Methane (CH4)	N/A	25.9
			Nitrous Oxide (N2O)	N/A	0.52
			Carbon Dioxide Equivalents (CO2e)	N/A	274,732
NFLSOPT1	NFLSOPT1	North FLSO Power Turbine 1*	Carbon Dioxide (CO2)	N/A	173,124
		*Annual emissions are based on 2 turbines operating for 8,760 hours, with the 3rd operating for 1,036 hours.	Methane (CH4)	N/A	10.2
			Nitrous Oxide (N2O)	N/A	0.33
			Carbon Dioxide Equivalents (CO2e)	N/A	173,476
NFLSOPT2	NFLSOPT2	North FLSO Power Turbine 2*	Carbon Dioxide (CO2)	N/A	173,124
		*Annual emissions are based on 2 turbines operating for 8,760 hours, with the 3rd operating for 1,036 hours.	Methane (CH4)	N/A	10.2
			Nitrous Oxide (N2O)	N/A	0.33
			Carbon Dioxide Equivalents (CO2e)	N/A	173,476
NFLSOPT3	NFLSOPT3	North FLSO Power Turbine 3*	Carbon Dioxide (CO2)	N/A	20,474
		*Annual emissions are based on 2 turbines operating	Methane (CH4)	N/A	1.2

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

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AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND	(B) TPY
		for 8,760 hours, with the 3rd operating for 1,036 hours.	Nitrous Oxide (N2O)	N/A	0.039
			Carbon Dioxide Equivalents (CO2e)	N/A	20,516
SFLSOPT1	SFLSOPT1	South FLSO Power Turbine 1*	Carbon Dioxide (CO2)	N/A	173,124
		*Annual emissions are based on 2 turbines operating for 8,760 hours, with the 3rd operating for 1,036 hours.	Methane (CH4)	N/A	10.2
			Nitrous Oxide (N2O)	N/A	0.33
			Carbon Dioxide Equivalents (CO2e)	N/A	173,476
SFLSOPT2	SFLSOPT2	South FLSO Power Turbine 2*	Carbon Dioxide (CO2)	N/A	173,124
		*Annual emissions are based on 2 turbines operating for 8,760 hours, with the 3rd operating for 1,036 hours.	Methane (CH4)	N/A	10.2
			Nitrous Oxide (N2O)	N/A	0.33
			Carbon Dioxide Equivalents (CO2e)	N/A	173,476
SFLSOPT3	SFLSOPT3	South FLSO Power Turbine 3*	Carbon Dioxide (CO2)	N/A	20,474
		*Annual emissions are based on 2 turbines operating for 8,760 hours, with the 3rd operating for 1,036 hours.	Methane (CH4)	N/A	1.2
			Nitrous Oxide (N2O)	N/A	0.039
			Carbon Dioxide Equivalents (CO2e)	N/A	20,516
NESGEN1	NESGEN1	North FLSO Essential Generator 1	Carbon Dioxide (CO2)	N/A	2,767
			Methane (CH4)	N/A	0.11
			Nitrous Oxide (N2O)	N/A	0.022
			Carbon Dioxide Equivalents (CO2e)	N/A	2,776
NESGEN2	NESGEN2	North FLSO Essential Generator 2	Carbon Dioxide (CO2)	N/A	2,767
			Methane (CH4)	N/A	0.11
			Nitrous Oxide (N2O)	N/A	0.022
			Carbon Dioxide Equivalents (CO2e)	N/A	2,776
SESGEN1	SESGEN1	South FLSO Essential Generator 1	Carbon Dioxide (CO2)	N/A	2,767
			Methane (CH4)	N/A	0.11
			Nitrous Oxide (N2O)	N/A	0.022
			Carbon Dioxide Equivalents (CO2e)	N/A	2,776
SESGEN2	SESGEN2	South FLSO Essential Generator 2	Carbon Dioxide (CO2)	N/A	2,767
			Methane (CH4)	N/A	0.11
			Nitrous Oxide (N2O)	N/A	0.022
			Carbon Dioxide Equivalents (CO2e)	N/A	2,776
NFLSOEGN	NFLSOEGN	North FLSO Emergency Generator	Carbon Dioxide (CO2)	N/A	49
			Methane (CH4)	N/A	2.0E-03
			Nitrous Oxide (N2O)	N/A	4.0E-04
			Carbon Dioxide Equivalents (CO2e)	N/A	49
SFLSOEGN	SFLSOEGN	South FLSO Emergency Generator	Carbon Dioxide (CO2)	N/A	49
			Methane (CH4)	N/A	2.0E-03
			Nitrous Oxide (N2O)	N/A	4.0E-04
			Carbon Dioxide Equivalents (CO2e)	N/A	49
NFLSOFP1	NFLSOFP1	North FLSO Fire Pump 1	Carbon Dioxide (CO2)	N/A	75
			Methane (CH4)	N/A	3.0E-03
			Nitrous Oxide (N2O)	N/A	6.1E-04
			Carbon Dioxide Equivalents (CO2e)	N/A	75

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	6/5/2014	Permit No.:	TBD	Regulated Entity No.:	107273930
Area Name:	Lavaca Bay LNG Project			Customer Reference No.:	604576488

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND	(B) TPY
NFLSOFP2	NFLSOFP2	North FLSO Fire Pump 2	Carbon Dioxide (CO2)	N/A	75
			Methane (CH4)	N/A	3.0E-03
			Nitrous Oxide (N2O)	N/A	6.1E-04
			Carbon Dioxide Equivalents (CO2e)	N/A	75
SFLSOFP1	SFLSOFP1	South FLSO Fire Pump 1	Carbon Dioxide (CO2)	N/A	75
			Methane (CH4)	N/A	3.0E-03
			Nitrous Oxide (N2O)	N/A	6.1E-04
			Carbon Dioxide Equivalents (CO2e)	N/A	75
SFLSOFP2	SFLSOFP2	South FLSO Fire Pump 2	Carbon Dioxide (CO2)	N/A	75
			Methane (CH4)	N/A	3.0E-03
			Nitrous Oxide (N2O)	N/A	6.1E-04
			Carbon Dioxide Equivalents (CO2e)	N/A	75
NFLSOCF	NFLSOCF	North FLSO Cold Flare	Carbon Dioxide (CO2)	N/A	5,598
			Methane (CH4)	N/A	19.6
			Nitrous Oxide (N2O)	N/A	0.011
			Carbon Dioxide Equivalents (CO2e)	N/A	6,092
SFLSOCF	SFLSOCF	South FLSO Cold Flare	Carbon Dioxide (CO2)	N/A	5,598
			Methane (CH4)	N/A	19.6
			Nitrous Oxide (N2O)	N/A	0.011
			Carbon Dioxide Equivalents (CO2e)	N/A	6,092
NFLSOWF	NFLSOWF	North FLSO Warm Flare	Carbon Dioxide (CO2)	N/A	5,581
			Methane (CH4)	N/A	19.5
			Nitrous Oxide (N2O)	N/A	0.011
			Carbon Dioxide Equivalents (CO2e)	N/A	6,072
SFLSOWF	SFLSOWF	South FLSO Warm Flare	Carbon Dioxide (CO2)	N/A	5,581
			Methane (CH4)	N/A	19.5
			Nitrous Oxide (N2O)	N/A	0.011
			Carbon Dioxide Equivalents (CO2e)	N/A	6,072
NFLSOTRMF	NFLSOTRMF	North FLSO Tank Relief and Maintenance Flare	Carbon Dioxide (CO2)	N/A	10,829
		[includes LNG tank inspection, and LNGC gas-in and cooldown emissions]	Methane (CH4)	N/A	37.0
			Nitrous Oxide (N2O)	N/A	0.020
			Carbon Dioxide Equivalents (CO2e)	N/A	11,761
SFLSOTRMF	SFLSOTRMF	South FLSO Tank Relief and Maintenance Flare	Carbon Dioxide (CO2)	N/A	10,829
		[includes LNG tank inspection, and LNGC gas-in and cooldown emissions]	Methane (CH4)	N/A	37.0
			Nitrous Oxide (N2O)	N/A	0.020
			Carbon Dioxide Equivalents (CO2e)	N/A	11,761
NFLSOTMV	NFSLOTMV	North FLSO Tank Maintenance Vent	Carbon Dioxide (CO2)	N/A	41.6
		[includes LNG tank inspection, and LNGC gas-in and cooldown emissions]	Methane (CH4)	N/A	26.4
			Nitrous Oxide (N2O)	N/A	0
			Carbon Dioxide Equivalents (CO2e)	N/A	702
SFLSOTMV	SFLSOTMV	South FLSO Tank Maintenance Vent	Carbon Dioxide (CO2)	N/A	41.6
		[includes LNG tank inspection, and LNGC gas-in and	Methane (CH4)	N/A	26.4

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	6/5/2014	Permit No.:	TBD	Regulated Entity No.:	107273930
Area Name:	Lavaca Bay LNG Project			Customer Reference No.:	604576488

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND	(B) TPY
		cooldown emissions]	Nitrous Oxide (N2O)	N/A	0
			Carbon Dioxide Equivalents (CO2e)	N/A	702
NFLSOFOTK1	NFLSOFOTK1	N FLSO Fwd Machinery Space Storage Tank 1	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
NFLSOFOTK2	NFLSOFOTK2	N FLSO Fwd Machinery Space Storage Tank 2	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
NFLSOFOTK3	NFLSOFOTK3	N FLSO Fwd Machinery Space Service Tank 1	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
NFLSOFOTK4	NFLSOFOTK4	N FLSO Fwd Machinery Space Service Tank 2	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
NFLSOFOTK5	NFLSOFOTK5	N FLSO Aft Machinery Space Service Tank 1	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
SFLSOFOTK1	SFLSOFOTK1	S FLSO Fwd Machinery Space Storage Tank 1	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
SFLSOFOTK2	SFLSOFOTK2	S FLSO Fwd Machinery Space Storage Tank 2	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
SFLSOFOTK3	SFLSOFOTK3	S FLSO Fwd Machinery Space Service Tank 1	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
SFLSOFOTK4	SFLSOFOTK4	S FLSO Fwd Machinery Space Service Tank 2	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
SFLSOFOTK5	SFLSOFOTK5	S FLSO Aft Machinery Space Service Tank 1	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
NFLSOFUG	NFLSOFUG	North FLSO Fugitive Emissions	Carbon Dioxide (CO2)	N/A	0.0
			Methane (CH4)	N/A	2.90
			Nitrous Oxide (N2O)	N/A	0.0
			Carbon Dioxide Equivalents (CO2e)	N/A	72.5
SFLSOFUG	SFLSOFUG	South FLSO Fugitive Emissions	Carbon Dioxide (CO2)	N/A	0.0
			Methane (CH4)	N/A	2.90
			Nitrous Oxide (N2O)	N/A	0.0
			Carbon Dioxide Equivalents (CO2e)	N/A	72.5
OSPT1	OSPT1	Onshore Power Turbine 1	Carbon Dioxide (CO2)	N/A	72,977
			Methane (CH4)	N/A	1.4
			Nitrous Oxide (N2O)	N/A	0.14
			Carbon Dioxide Equivalents (CO2e)	N/A	73,053
OSPT2	OSPT2	Onshore Power Turbine 2	Carbon Dioxide (CO2)	N/A	72,977
			Methane (CH4)	N/A	1.4
			Nitrous Oxide (N2O)	N/A	0.14
			Carbon Dioxide Equivalents (CO2e)	N/A	73,053
OSPT3	OSPT3	Onshore Power Turbine 3	Carbon Dioxide (CO2)	N/A	72,977
			Methane (CH4)	N/A	1.4
			Nitrous Oxide (N2O)	N/A	0.14
			Carbon Dioxide Equivalents (CO2e)	N/A	73,053
OSPT4	OSPT4	Onshore Power Turbine 4	Carbon Dioxide (CO2)	N/A	72,977
			Methane (CH4)	N/A	1.4
			Nitrous Oxide (N2O)	N/A	0.14
			Carbon Dioxide Equivalents (CO2e)	N/A	73,053
OSPT5	OSPT5	Onshore Power Turbine 5	Carbon Dioxide (CO2)	N/A	72,977
			Methane (CH4)	N/A	1.4
			Nitrous Oxide (N2O)	N/A	0.14
			Carbon Dioxide Equivalents (CO2e)	N/A	73,053
OSPT6	OSPT6	Onshore Power Turbine 6	Carbon Dioxide (CO2)	N/A	72,977
			Methane (CH4)	N/A	1.4

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	6/5/2014	Permit No.:	TBD	Regulated Entity No.:	107273930
Area Name:	Lavaca Bay LNG Project			Customer Reference No.:	604576488

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND	(B) TPY
			Nitrous Oxide (N2O)	N/A	0.14
			Carbon Dioxide Equivalents (CO2e)	N/A	73,053
OSPT7	OSPT7	Onshore Power Turbine 7* * The 7th turbine will be in standby. While any of the 7 turbines may run at a given time, only a maximum of 6 will run simultaneously. Annual emissions are based on 6 turbines operating for 8,760 hours.	Carbon Dioxide (CO2)	N/A	0.0
			Methane (CH4)	N/A	0.0
			Nitrous Oxide (N2O)	N/A	0.0
			Carbon Dioxide Equivalents (CO2e)	N/A	0.0
OSSTBLR1	OSSTBLR1	Onshore Steam Boiler 1	Carbon Dioxide (CO2)	N/A	110,514
			Methane (CH4)	N/A	2.1
			Nitrous Oxide (N2O)	N/A	0.21
			Carbon Dioxide Equivalents (CO2e)	N/A	110,628
OSSTBLR2	OSSTBLR2	Onshore Steam Boiler 2	Carbon Dioxide (CO2)	N/A	110,514
			Methane (CH4)	N/A	2.1
			Nitrous Oxide (N2O)	N/A	0.21
			Carbon Dioxide Equivalents (CO2e)	N/A	110,628
OSTO1	OSTO1	Onshore Thermal Oxidizer 1	Carbon Dioxide (CO2)	N/A	256,935
			Methane (CH4)	N/A	1.3
			Nitrous Oxide (N2O)	N/A	0.086
			Carbon Dioxide Equivalents (CO2e)	N/A	256,994
OSTO2	OSTO2	Onshore Thermal Oxidizer 2	Carbon Dioxide (CO2)	N/A	256,935
			Methane (CH4)	N/A	1.3
			Nitrous Oxide (N2O)	N/A	0.086
			Carbon Dioxide Equivalents (CO2e)	N/A	256,994
OSRGH1	OSRGH1	Onshore Regen Gas Heater 1	Carbon Dioxide (CO2)	N/A	24,388
			Methane (CH4)	N/A	0.46
			Nitrous Oxide (N2O)	N/A	0.046
			Carbon Dioxide Equivalents (CO2e)	N/A	24,413
OSRGH2	OSRGH2	Onshore Regen Gas Heater 2	Carbon Dioxide (CO2)	N/A	24,388
			Methane (CH4)	N/A	0.46
			Nitrous Oxide (N2O)	N/A	0.046
			Carbon Dioxide Equivalents (CO2e)	N/A	24,413
OSFP	OSEGN1	Onshore Emergency Generator 1	Carbon Dioxide (CO2)	N/A	253
			Methane (CH4)	N/A	0.010
			Nitrous Oxide (N2O)	N/A	2.1E-03
			Carbon Dioxide Equivalents (CO2e)	N/A	254
OSEGN1	OSEGN2	Onshore Emergency Generator 2	Carbon Dioxide (CO2)	N/A	253
			Methane (CH4)	N/A	0.010
			Nitrous Oxide (N2O)	N/A	2.1E-03
			Carbon Dioxide Equivalents (CO2e)	N/A	254
OSEGN2	OSFP	Onshore Fire Pump	Carbon Dioxide (CO2)	N/A	6
			Methane (CH4)	N/A	2.4E-04
			Nitrous Oxide (N2O)	N/A	4.9E-05
			Carbon Dioxide Equivalents (CO2e)	N/A	6

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	6/5/2014	Permit No.:	TBD	Regulated Entity No.:	107273930
Area Name:	Lavaca Bay LNG Project			Customer Reference No.:	604576488

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND	(B) TPY
OSCV	OSCV	Onshore Cold Vent	Carbon Dioxide (CO2)	N/A	N/A
		[emergency use only, excluded from PTE]	Methane (CH4)	N/A	N/A
			Nitrous Oxide (N2O)	N/A	N/A
			Carbon Dioxide Equivalents (CO2e)	N/A	N/A
OSGF	OSGF	Onshore Ground Flare	Carbon Dioxide (CO2)	N/A	215
			Methane (CH4)	N/A	0.75
			Nitrous Oxide (N2O)	N/A	4.0E-04
			Carbon Dioxide Equivalents (CO2e)	N/A	234
NCT1	NCT1	North Cooling Tower Cell 1	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
NCT2	NCT2	North Cooling Tower Cell 2	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
NCT3	NCT3	North Cooling Tower Cell 3	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
NCT4	NCT4	North Cooling Tower Cell 4	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
NCT5	NCT5	North Cooling Tower Cell 5	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
NCT6	NCT6	North Cooling Tower Cell 6	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
NCT7	NCT7	North Cooling Tower Cell 7	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
NCT8	NCT8	North Cooling Tower Cell 8	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
NCT9	NCT9	North Cooling Tower Cell 9	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
NCT10	NCT10	North Cooling Tower Cell 10	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
NCT11	NCT11	North Cooling Tower Cell 11	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
NCT12	NCT12	North Cooling Tower Cell 12	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
SCT1	SCT1	South Cooling Tower Cell 1	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
SCT2	SCT2	South Cooling Tower Cell 2	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
SCT3	SCT3	South Cooling Tower Cell 3	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
SCT4	SCT4	South Cooling Tower Cell 4	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
SCT5	SCT5	South Cooling Tower Cell 5	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
SCT6	SCT6	South Cooling Tower Cell 6	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
SCT7	SCT7	South Cooling Tower Cell 7	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
SCT8	SCT8	South Cooling Tower Cell 8	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
SCT9	SCT9	South Cooling Tower Cell 9	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
SCT10	SCT10	South Cooling Tower Cell 10	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
SCT11	SCT11	South Cooling Tower Cell 11	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
SCT12	SCT12	South Cooling Tower Cell 12	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
OSHCST1	OSHCST1	Onshore Hydrocarbon Storage Tank 1	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
OSHCST2	OSHCST2	Onshore Hydrocarbon Storage Tank 2	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
OSFOTK1	OSFOTK1	Onshore Emergency Generator Storage Tank 1	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
OSFOTK2	OSFOTK2	Onshore Emergency Generator Storage Tank 2	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
OSFOTK3	OSFOTK3	Onshore Fire Pump Storage Tank 1	NO GHG EMISSIONS FROM THIS SOURCE.	N/A	N/A
OSFUG	OSFUG	Onshore Plant Fugitive Emissions	Carbon Dioxide (CO2)	N/A	0.16
			Methane (CH4)	N/A	4.3
			Nitrous Oxide (N2O)	N/A	0.0
			Carbon Dioxide Equivalents (CO2e)	N/A	106.7

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	6/5/2014	Permit No.:	TBD	Regulated Entity No.:	107273930
Area Name:	Lavaca Bay LNG Project			Customer Reference No.:	604576488

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

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
						5. Building	6. Height Above	7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	Height (Ft.)	Ground (Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
NFLSOCT1	NFLSOCT1	North FLSO Compressor Turbine 1	14	738285.9	3169855.7		220.4	9.5	163	823	N/A	N/A	N/A
NFLSOCT2	NFLSOCT2	North FLSO Compressor Turbine 2	14	738275.0	3169814.0		220.4	9.5	163	823	N/A	N/A	N/A
NFLSOCT3	NFLSOCT3	North FLSO Compressor Turbine 3	14	738263.7	3169772.0		220.4	9.5	163	823	N/A	N/A	N/A
NFLSOCT4	NFLSOCT4	North FLSO Compressor Turbine 4	14	738252.4	3169730.5		220.4	9.5	163	823	N/A	N/A	N/A
SFLSOCT1	SFLSOCT1	South FLSO Compressor Turbine 1	14	738307.0	3169426.0		220.4	9.5	163	823	N/A	N/A	N/A
SFLSOCT2	SFLSOCT2	South FLSO Compressor Turbine 2	14	738306.7	3169382.7		220.4	9.5	163	823	N/A	N/A	N/A
SFLSOCT3	SFLSOCT3	South FLSO Compressor Turbine 3	14	738306.3	3169339.3		220.4	9.5	163	823	N/A	N/A	N/A
SFLSOCT4	SFLSOCT4	South FLSO Compressor Turbine 4	14	738305.5	3169295.8		220.4	9.5	163	823	N/A	N/A	N/A
NFLSOPT1	NFLSOPT1	North FLSO Power Turbine 1	14	738251.3	3169698.0		147.3	9.8	82	743	N/A	N/A	N/A
NFLSOPT2	NFLSOPT2	North FLSO Power Turbine 2	14	738248.0	3169687.0		147.3	9.8	82	743	N/A	N/A	N/A
NFLSOPT3	NFLSOPT3	North FLSO Power Turbine 3	14	738245.0	3169676.0		147.3	9.8	82	743	N/A	N/A	N/A
SFLSOPT1	SFLSOPT1	South FLSO Power Turbine 1	14	738312.0	3169264.0		147.3	9.8	82	743	N/A	N/A	N/A
SFLSOPT2	SFLSOPT2	South FLSO Power Turbine 2	14	738312.1	3169252.6		147.3	9.8	82	743	N/A	N/A	N/A
SFLSOPT3	SFLSOPT3	South FLSO Power Turbine 3	14	738312.0	3169241.0		147.3	9.8	82	743	N/A	N/A	N/A
NESGEN1	NESGEN1	North FLSO Essential Generator 1	14	738204.5	3169644.8		180.9	3.9	56	590	N/A	N/A	N/A
NESGEN2	NESGEN2	North FLSO Essential Generator 2	14	738206.2	3169644.4		180.9	3.9	56	590	N/A	N/A	N/A
SESGEN1	SESGEN1	South FLSO Essential Generator 1	14	738279.9	3169201.1		180.9	3.9	56	590	N/A	N/A	N/A
SESGEN2	SESGEN2	South FLSO Essential Generator 2	14	738281.6	3169201.1		180.9	3.9	56	590	N/A	N/A	N/A
NFLSOEGN	NFLSOEGN	North FLSO Emergency Generator	14	738193.1	3169641.5		65.1	1.6	73.5	835	N/A	N/A	N/A
SFLSOEGN	SFLSOEGN	South FLSO Emergency Generator	14	738669.8	3169195.2		65.1	1.6	73.5	835	N/A	N/A	N/A
NFLSOFP1	NFLSOFP1	North FLSO Fire Pump 1	14	738305.7	3169882.7		89.9	1.6	113	784	N/A	N/A	N/A
NFLSOFP2	NFLSOFP2	North FLSO Fire Pump 2	14	738305.7	3169882.7		89.9	1.6	113	784	N/A	N/A	N/A

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	**6/5/2014**	**Permit No.:**	**TBD**	**Regulated Entity No.:**	**107273930**
Area Name:	**Lavaca Bay LNG Project**			**Customer Reference No.:**	**604576488**

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

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
						5. Building	6. Height Above	7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	Height (Ft.)	Ground (Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
SFLSOFP1	SFLSOFP1	South FLSO Fire Pump 1	14	738319.7	3169456.5		89.9	1.6	113	784	N/A	N/A	N/A
SFLSOFP2	SFLSOFP2	South FLSO Fire Pump 2	14	738319.7	3169456.5		89.9	1.6	113	784	N/A	N/A	N/A
NFLSOCF	NFLSOCF	North FLSO Cold Flare	14	738313.5	3169923.6		403.5	39.7	66	1832	N/A	N/A	N/A
SFLSOCF	SFLSOCF	South FLSO Cold Flare	14	738316.7	3169498.4		403.5	39.7	66	1832	N/A	N/A	N/A
NFLSOWF	NFLSOWF	North FLSO Warm Flare	14	738313.5	3169923.6		403.5	39.7	66	1832	N/A	N/A	N/A
SFLSOWF	SFLSOWF	South FLSO Warm Flare	14	738316.7	3169498.4		403.5	39.7	66	1832	N/A	N/A	N/A
NFLSOTMEP	NFLSOTMEP	North FLSO Tank Maintenance Exhaust Port	14	738313.5	3169923.6		403.5	TBD	TBD	TBD	N/A	N/A	N/A
SFLSOTMEP	SFLSOTMEP	South FLSO Tank Maintenance Exhaust Port	14	738316.7	3169498.4		403.5	TBD	TBD	TBD	N/A	N/A	N/A
NFLSOCV	NFLSOCV	North FLSO Cold Vent	14	TBD	TBD		TBD	TBD	TBD	TBD	N/A	N/A	N/A
SFLSOCV	SFLSOCV	South FLSO Cold Vent	14	TBD	TBD		TBD	TBD	TBD	TBD	N/A	N/A	N/A
NFLSOFOTK1	NFLSOFOTK1	N FLSO Fwd Machinery Space Storage Tank 1	14	TBD	TBD		TBD	TBD	TBD	Ambient	N/A	N/A	N/A
NFLSOFOTK2	NFLSOFOTK2	N FLSO Fwd Machinery Space Storage Tank 2	14	TBD	TBD		TBD	TBD	TBD	Ambient	N/A	N/A	N/A
NFLSOFOTK3	NFLSOFOTK3	N FLSO Fwd Machinery Space Service Tank 1	14	TBD	TBD		TBD	TBD	TBD	Ambient	N/A	N/A	N/A
NFLSOFOTK4	NFLSOFOTK4	N FLSO Fwd Machinery Space Service Tank 2	14	TBD	TBD		TBD	TBD	TBD	Ambient	N/A	N/A	N/A
NFLSOFOTK5	NFLSOFOTK5	North FLSO Aft Machinery Space Service Tank 1	14	TBD	TBD		TBD	TBD	TBD	Ambient	N/A	N/A	N/A
SFLSOFOTK1	SFLSOFOTK1	S FLSO Fwd Machinery Space Storage Tank 1	14	TBD	TBD		TBD	TBD	TBD	Ambient	N/A	N/A	N/A
SFLSOFOTK2	SFLSOFOTK2	S FLSO Fwd Machinery Space Storage Tank 2	14	TBD	TBD		TBD	TBD	TBD	Ambient	N/A	N/A	N/A
SFLSOFOTK3	SFLSOFOTK3	S FLSO Fwd Machinery Space Service Tank 1	14	TBD	TBD		TBD	TBD	TBD	Ambient	N/A	N/A	N/A
SFLSOFOTK4	SFLSOFOTK4	S FLSO Fwd Machinery Space Service Tank 2	14	TBD	TBD		TBD	TBD	TBD	Ambient	N/A	N/A	N/A
SFLSOFOTK5	SFLSOFOTK5	South FLSO Aft Machinery Space Service Tank 1	14	TBD	TBD		TBD	TBD	TBD	Ambient	N/A	N/A	N/A
NFLSOFUG	NFLSOFUG	North FLSO Fugitive Emissions	14	738171.8	3169610.0		N/A	N/A	N/A	Ambient	1099	226	15
SFLSOFUG	SFLSOFUG	South FLSO Fugitive Emissions	14	738256.7	3169159.6		N/A	N/A	N/A	Ambient	1099	226	0

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	**6/5/2014**	**Permit No.:**	**TBD**	**Regulated Entity No.:**	**107273930**
Area Name:	**Lavaca Bay LNG Project**			**Customer Reference No.:**	**604576488**

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

AIR CONTAMINANT DATA			**EMISSION POINT DISCHARGE PARAMETERS**										
1. Emission Point			**4. UTM Coordinates of Emission Point**			**Source**							
						5. Building	**6. Height Above**	**7. Stack Exit Data**			**8. Fugitives**		
EPN (A)	**FIN (B)**	**Name (C)**	**Zone**	**East (Meters)**	**North (Meters)**	**Height (Ft.)**	**Ground (Ft.)**	**Diameter (Ft.) (A)**	**Velocity (FPS) (B)**	**Temperature (°F) (C)**	**Length (Ft.) (A)**	**Width (Ft.) (B)**	**Axis Degrees (C)**
OSPT1	OSPT1	Onshore Power Turbine 1	14	738423.8	3170229.6		114.8	5.0	90	284	N/A	N/A	N/A
OSPT2	OSPT2	Onshore Power Turbine 2	14	738417.2	3170216.7		114.8	5.0	90	284	N/A	N/A	N/A
OSPT3	OSPT3	Onshore Power Turbine 3	14	738410.4	3170203.9		114.8	5.0	90	284	N/A	N/A	N/A
OSPT4	OSPT4	Onshore Power Turbine 4	14	738399.8	3170183.7		114.8	5.0	90	284	N/A	N/A	N/A
OSPT5	OSPT5	Onshore Power Turbine 5	14	738393.0	3170170.6		114.8	5.0	90	284	N/A	N/A	N/A
OSPT6	OSPT6	Onshore Power Turbine 6	14	738386.0	3170158.0		114.8	5.0	90	284	N/A	N/A	N/A
OSPT7	OSPT7	Onshore Power Turbine 7	14	TBD	TBD		114.8	5.0	90	284	N/A	N/A	N/A
OSSTBLR1	OSSTBLR1	Onshore Steam Boiler 1	14	738637.3	3170186.8		114.8	5.1	70	527	N/A	N/A	N/A
OSSTBLR2	OSSTBLR2	Onshore Steam Boiler 2	14	738569.3	3170139.2		114.8	5.1	70	527	N/A	N/A	N/A
OSTO1	OSTO1	Onshore Thermal Oxidizer 1	14	738605.2	3170112.3		114.8	3.3	127	1472	N/A	N/A	N/A
OSTO2	OSTO2	Onshore Thermal Oxidizer 2	14	738673.3	3170159.9		114.8	3.3	127	1472	N/A	N/A	N/A
OSRGH1	OSRGH1	Onshore Regen Gas Heater 1	14	738576.2	3170128.9		114.8	2.4	70	527	N/A	N/A	N/A
OSRGH2	OSRGH2	Onshore Regen Gas Heater 2	14	738644.3	3170176.3		114.8	2.4	70	527	N/A	N/A	N/A
OSFP	OSFP	Onshore Fire Pump	14	738308.4	3170031.4		19.7	0.5	103	827	N/A	N/A	N/A
OSEGN1	OSEGN1	Onshore Emergency Generator 1	14	738444.2	3170229.1		19.7	2.3	103	892	N/A	N/A	N/A
OSEGN2	OSEGN2	Onshore Emergency Generator 2	14	738446.5	3170233.2		19.7	2.3	103	892	N/A	N/A	N/A
OSCV	OSCV	Onshore Cold Vent	14	738496.9	3170022.3		114.8	1.5	TBD	TBD	N/A	N/A	N/A
OSGH	OSGH	Onshore Ground Flare	14	738450.2	3169968.8		45.9	13.8	66	1832	N/A	N/A	N/A
NCT1	NCT1	North Cooling Tower Cell 1	14	738423.8	3170181.1		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
NCT2	NCT2	North Cooling Tower Cell 2	14	738417.3	3170168.9		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
NCT3	NCT3	North Cooling Tower Cell 3	14	738411.0	3170156.7		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
NCT4	NCT4	North Cooling Tower Cell 4	14	738404.5	3170144.4		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	**6/5/2014**	**Permit No.:**	**TBD**	**Regulated Entity No.:**	**107273930**
Area Name:	**Lavaca Bay LNG Project**			**Customer Reference No.:**	**604576488**

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

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
						5. Building	6. Height Above	7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	Height (Ft.)	Ground (Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
NCT5	NCT5	North Cooling Tower Cell 5	14	738398.0	3170132.0		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
NCT6	NCT6	North Cooling Tower Cell 6	14	738391.5	3170119.8		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
NCT7	NCT7	North Cooling Tower Cell 7	14	738436.2	3170174.5		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
NCT8	NCT8	North Cooling Tower Cell 8	14	738429.0	3170163.2		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
NCT9	NCT9	North Cooling Tower Cell 9	14	738423.4	3170150.2		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
NCT10	NCT10	North Cooling Tower Cell 10	14	738416.9	3170137.8		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
NCT11	NCT11	North Cooling Tower Cell 11	14	738410.3	3170125.5		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
NCT12	NCT12	North Cooling Tower Cell 12	14	738404.0	3170113.3		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
SCT1	SCT1	South Cooling Tower Cell 1	14	738376.2	3170090.9		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
SCT2	SCT2	South Cooling Tower Cell 2	14	738369.8	3170078.8		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
SCT3	SCT3	South Cooling Tower Cell 3	14	738363.4	3170066.5		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
SCT4	SCT4	South Cooling Tower Cell 4	14	738356.9	3170054.1		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
SCT5	SCT5	South Cooling Tower Cell 5	14	738350.4	3170041.7		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
SCT6	SCT6	South Cooling Tower Cell 6	14	738343.9	3170029.6		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
SCT7	SCT7	South Cooling Tower Cell 7	14	738388.6	3170084.4		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
SCT8	SCT8	South Cooling Tower Cell 8	14	738382.2	3170072.2		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
SCT9	SCT9	South Cooling Tower Cell 9	14	738375.8	3170060.0		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
SCT10	SCT10	South Cooling Tower Cell 10	14	738369.2	3170047.6		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
SCT11	SCT11	South Cooling Tower Cell 11	14	738362.7	3170035.2		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
SCT12	SCT12	South Cooling Tower Cell 12	14	738356.3	3170023.0		51.5	44.0	33	Amb. + 4.7F	N/A	N/A	N/A
OSHCTK1	OSHCTK1	Onshore Hydrocarbon Storage Tank 1	14	738430.2	3170065.5		TBD	TBD	TBD	Ambient	N/A	N/A	N/A
OSHCTK2	OSHCTK2	Onshore Hydrocarbon Storage Tank 2	14	738411.7	3170030.0		TBD	TBD	TBD	Ambient	N/A	N/A	N/A

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	6/5/2014	Permit No.:	TBD	Regulated Entity No.:	107273930
Area Name:	Lavaca Bay LNG Project			Customer Reference No.:	604576488

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

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
						5. Building	6. Height Above	7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	Height (Ft.)	Ground (Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
OSFOTK1	OSFOTK1	Onshore Emergency Generator Service Tank 1	14	TBD	TBD		TBD	TBD	TBD	Ambient	N/A	N/A	N/A
OSFOTK2	OSFOTK2	Onshore Emergency Generator Service Tank 2	14	TBD	TBD		TBD	TBD	TBD	Ambient	N/A	N/A	N/A
OSFOTK3	OSFOTK3	Onshore Fire Pump Service Tank 1	14	TBD	TBD		TBD	TBD	TBD	Ambient	N/A	N/A	N/A
OSFUG	OSFUG	Onshore Plant Fugitive Emissions	14	738380.8	3169890.7		N/A	N/A	N/A	Ambient	1604	1122	56

EPN = Emission Point Number
FIN = Facility Identification Number

TABLE 2

MATERIAL BALANCE

This material balance table is used to quantify possible emissions of air contaminants and special emphasis should be placed on potential air contaminants, for example: If feed contains sulfur,show distribution to all products. Please relate each material (or group of materials) listed to its respective location in the process flow diagram by assigning point numbers (taken from the flow diagram) to each material.

LIST EVERY MATERIAL INVOLVED IN EACH OF THE FOLLOWING GROUPS	Point No. from Flow Diagram	Process Rate (lbs/hr orSCFM) standard conditions: 70°F 14.7 PSIA. Check appropriate column at right for each process.	Measurement	Estimation	Calculation
1. Raw Materials - Input Natural gas	N/A	1.258 billion scf/day		x	
2. Fuels - Input See Appendix B - Emission Calculations	N/A				x
3. Products & By-Products - Output LNG Hydrocarbon condensate	N/A	LNG: 10 million tons per annum (MPTA) HC: 15.7 bbl/hr (equiv. of 0.33 million scf/day)		x	
4. Solid Wastes - Output					
5. Liquid Wastes - Output					
6. Airborne Waste (Solid) - Output See Table 1(a) and Appendix B - Emission Calculations	N/A				x
7. Airborne Wastes (Gaseous) - Output See Table 1(a) and Appendix B - Emission Calculations	N/A				x

TABLE 3
SIMPLIFIED DATA SHEET
FOR GASEOUS ABATEMENT DEVICES

(Complete one table for each abatement device.)

1. Point Number (from flow diagram): OSTO1
2. Type Device: Onshore Thermal Oxidizer 1

Vapor Condenser
Absorber
Adsorber
Other (specify) Thermal Oxidizer

3. Manufacturer and Model or Type: N/A
4. Design Removal Efficiency of Affected Pollutants:

Gaseous Pollutant	Removal Efficiency
H_2S	99%
VOC	10 ppmvd at 3% O_2
CH_4	99.9%

5. Characteristics of Gas Stream: See Appendix B, Emission Calculations

	Temperature Degrees F	Static Pressure PSIG	Composition Mole %
INLET	147	8.8	See Appendix B, Emission Calculations
EXIT	1,472	0.15	See Appendix B, Emission Calculations

ABATEMENT DEVICE DATA INSTRUCTIONS

Attach separate sheets as necessary providing a description of the air pollution abatement device(s) or treatment including details regarding principles of operation, size, type, capacity, and the basis for calculating its efficiency.

TABLE 3
SIMPLIFIED DATA SHEET
FOR GASEOUS ABATEMENT DEVICES

(Complete one table for each abatement device.)

1. Point Number (from flow diagram): OSTO2
2. Type Device: Onshore Thermal Oxidizer 2

Vapor Condenser
Absorber
Adsorber
Other (specify) Thermal Oxidizer

3. Manufacturer and Model or Type: N/A
4. Design Removal Efficiency of Affected Pollutants:

Gaseous Pollutant	Removal Efficiency
H2S	99%
VOC	10 ppmvd at 3% O2
CH4	99.9%

5. Characteristics of Gas Stream: See Appendix B, Emission Calculations

	Temperature Degrees F	Static Pressure PSIG	Composition Mole %
INLET	147	8.8	See Appendix B, Emission Calculations
EXIT	1,472	0.15	See Appendix B, Emission Calculations

ABATEMENT DEVICE DATA INSTRUCTIONS

Attach separate sheets as necessary providing a description of the air pollution abatement device(s) or treatment including details regarding principles of operation, size, type, capacity, and the basis for calculating its efficiency.

TABLE 6

BOILERS AND HEATERS

Type of Device: Onshore Steam Boiler 1	Manufacturer: TBD
Number from flow diagram: OSSTBLR1	Model Number: TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural gas	See composition of "Feed Gas" in Appendix B, Emission Calculations	TBD	Average TBD	Design Maximum 3,525
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 1,020 Btu/scf (HHV)	Average TBD scfm* TBD % excess (vol)	Design Maximum TBD scfm * TBD % excess (vol)

HEAT TRANSFER MEDIUM

Type Transfer Medium	Temperature °F		Pressure (psia)		Flow Rate (specify units)	
(Water, oil, etc.)	Input	Output	Input	Output	Average	Design Maxim
Steam	TBD	302	TBD	51.5	TBD	TBD

OPERATING CHARACTERISTICS

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

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
1.54 m (5.1 ft.)	35.0 m (114.8 ft.)	TBD	69.6	527	83,735

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
N/A	See Appendix B, Emission Calculations

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

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

*Standard Conditions: 70°F,14.7 psia

TABLE 6

BOILERS AND HEATERS

Type of Device: Onshore Steam Boiler 2		Manufacturer: TBD		
Number from flow diagram: OSSTBLR2		Model Number: TBD		
CHARACTERISTICS OF INPUT				
Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural gas	See composition of "Feed Gas" in Appendix B, Emission Calculations	TBD	Average TBD	Design Maximum 3,525
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 1,020 Btu/scf (HHV)	Average TBD scfm* TBD % excess (vol)	Design Maximum TBD scfm * TBD % excess (vol)

HEAT TRANSFER MEDIUM						
Type Transfer Medium	Temperature °F		Pressure (psia)		Flow Rate (specify units)	
(Water, oil, etc.)	Input	Output	Input	Output	Average	Design Maxim
Steam	TBD	302	TBD	51.5	TBD	TBD

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

STACK PARAMETERS					
Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
1.54 m (5.1 ft.)	35.0 m (114.8 ft.)	TBD	69.6	527	83,735

CHARACTERISTICS OF OUTPUT	
Material	Chemical Composition of Exit Gas Released (% by Volume)
N/A	See Appendix B, Emission Calculations
Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.	

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

*Standard Conditions: 70°F,14.7 psia

TABLE 6

BOILERS AND HEATERS

Type of Device: Onshore Regen Gas Heater 1	Manufacturer: TBD
Number from flow diagram: OSRGH1	Model Number: TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
			Average	Design Maximum
Natural gas	TBD	TBD	TBD	778
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units)	Average	Design Maximum
		1,020 Btu/scf (HHV)	TBD scfm* TBD % excess (vol)	TBD scfm * TBD % excess (vol)

HEAT TRANSFER MEDIUM

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

OPERATING CHARACTERISTICS

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

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
0.72 m (2.4 ft.)	35.0 m (114.8 ft.)	TBD	69.6	527	18,478

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
N/A	See Appendix B, Emission Calculations

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

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

*Standard Conditions: 70°F,14.7 psia

TABLE 6

BOILERS AND HEATERS

Type of Device: Onshore Regen Gas Heater 2		Manufacturer: TBD		
Number from flow diagram: OSRGH2		Model Number: TBD		
CHARACTERISTICS OF INPUT				
Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural gas	TBD	TBD	Average TBD	Design Maximum 778
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 1,020 Btu/scf (HHV)	Average TBD scfm* TBD % excess (vol)	Design Maximum TBD scfm * TBD % excess (vol)

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

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

STACK PARAMETERS					
Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
0.72 m (2.4 ft.)	35.0 m (114.8 ft.)	(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
		TBD	69.6	527	18,478

CHARACTERISTICS OF OUTPUT	
Material	Chemical Composition of Exit Gas Released (% by Volume)
N/A	See Appendix B, Emission Calculations
Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.	

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

*Standard Conditions: 70°F,14.7 psia

TABLE 7(a)

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

N FLSO Fwd Machinery Space Storage Tank 1

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: Excelerate Liquefaction Operations (Port Lavaca), LLC
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. NFLSOFOTK1 4. Emission Point No. NFLSOFOTK1
5. FIN ______ CIN ______
6. Status: New tank [x] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics*** NOTE: Tank dimensions are estimated, for potential emission purposes only. Actual dimensions TBD.

1. Dimensions
   a. Shell Height : 33.5 ft.
   b. Diameter: 33.5 ft.
   c. Maximum Liquid Height : 33.5 ft.
   d. Nominal Capacity or Working Volume: 220,582 gallons.
   e. Turnovers per year: 1.08
   f. Net Throughput : 238,099 gallons/year.
   g. Maximum Filling Rate: N/A gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe Unknown)
   b. Shell Condition : Good [x] Poor [ ]
   c. Roof Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe Unknown)
   d. Roof Condition : Good [x] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [x]
   b. Roof Height: Unknown ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): N/A ft.
   d. Slope (*Cone Roof Only*): 0.0625 ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve	N/A	N/A	N/A	N/A
Pressure Vent Valve	1	0.03		Atmosphere
Vacuum Vent Valve	1		-0.03	
Open Vent Valve	N/A			N/A

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ____________________ Tank No. NFLSOFOTK1

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [ ] Petroleum Distillates [x] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [x] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ____________________
   b. CAS Number: ____________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ___________
4. Multiple Component Information
   a. Mixture Name: Distillate fuel oil No. 2
   b. Average Liquid Surface Temperature: 73.50 °F.
   c. Minimum Liquid Surface Temperature: 60.93 °F.
   d. Maximum Liquid Surface Temperature: 85.42 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 0.0101 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 0.0067 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 0.0142 psia.
   h. Liquid Molecular Weight: 188
   i. Vapor Molecular Weight: 130

j. Chemical Components Information		N/A		
Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(a)

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

N FLSO Fwd Machinery Space Storage Tank 2

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: Excelerate Liquefaction Operations (Port Lavaca), LLC
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. NFLSOFOTK2 4. Emission Point No. NFLSOFOTK2
5. FIN ______ CIN ______
6. Status: New tank [x] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics*** NOTE: Tank dimensions are estimated, for potential emission purposes only. Actual dimensions TBD.

1. Dimensions
   a. Shell Height : 38.0 ft.
   b. Diameter: 38.0 ft.
   c. Maximum Liquid Height : 38.0 ft.
   d. Nominal Capacity or Working Volume: 322,287 gallons.
   e. Turnovers per year: 0.74
   f. Net Throughput : 238,099 gallons/year.
   g. Maximum Filling Rate: N/A gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe Unknown)
   b. Shell Condition : Good [x] Poor [ ]
   c. Roof Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe Unknown)
   d. Roof Condition : Good [x] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [x]
   b. Roof Height: Unknown ft. (*not including shell height*)
   c. Radius (*Dome Roof Only*): N/A ft.
   d. Slope (*Cone Roof Only*): 0.0625 ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve	N/A	N/A	N/A	N/A
Pressure Vent Valve	1	0.03		Atmosphere
Vacuum Vent Valve	1		-0.03	
Open Vent Valve	N/A			N/A

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ____________________ Tank No. NFLSOFOTK2

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [ ] Petroleum Distillates [x] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [x] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ____________________
   b. CAS Number: ____________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ____________
4. Multiple Component Information
   a. Mixture Name: Distillate fuel oil No. 2
   b. Average Liquid Surface Temperature: 73.50 °F.
   c. Minimum Liquid Surface Temperature: 60.93 °F.
   d. Maximum Liquid Surface Temperature: 85.42 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 0.0101 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 0.0067 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 0.0142 psia.
   h. Liquid Molecular Weight: 188
   i. Vapor Molecular Weight: 130

j. Chemical Components Information N/A

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(a)

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

S FLSO Fwd Machinery Space Storage Tank 1

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: Excelerate Liquefaction Operations (Port Lavaca), LLC
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. SFLSOFOTK1   4. Emission Point No. SFLSOFOTK1
5. FIN ______   CIN ______
6. Status: New tank [x] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics*** NOTE: Tank dimensions are estimated, for potential emission purposes only. Actual dimensions TBD.

1. Dimensions
   - a. Shell Height : 33.5 ft.
   - b. Diameter: 33.5 ft.
   - c. Maximum Liquid Height : 33.5 ft.
   - d. Nominal Capacity or Working Volume: 220,582 gallons.
   - e. Turnovers per year: 1.08
   - f. Net Throughput : 238,099 gallons/year.
   - g. Maximum Filling Rate: N/A gallons/hour.
2. Paint Characteristics
   - a. Shell Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe Unknown)
   - b. Shell Condition : Good [x] Poor [ ]
   - c. Roof Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe Unknown)
   - d. Roof Condition : Good [x] Poor [ ]
3. Roof Characteristics
   - a. Roof Type: Dome [ ] Cone [x]
   - b. Roof Height: Unknown ft. (*not including shell height)*
   - c. Radius (*Dome Roof Only*): N/A ft.
   - d. Slope (*Cone Roof Only*): 0.0625 ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve	N/A	N/A	N/A	N/A
Pressure Vent Valve	1	0.03		Atmosphere
Vacuum Vent Valve	1		-0.03	
Open Vent Valve	N/A			N/A

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ____________________ Tank No. SFLSOFOTK1

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [ ] Petroleum Distillates [x] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [x] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ________________________________
   b. CAS Number: ________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: _______ psia.
   e. Liquid Molecular Weight: ___________
4. Multiple Component Information
   a. Mixture Name: Distillate fuel oil No. 2
   b. Average Liquid Surface Temperature: 73.50 °F.
   c. Minimum Liquid Surface Temperature: 60.93 °F.
   d. Maximum Liquid Surface Temperature: 85.42 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 0.0101 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 0.0067 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 0.0142 psia.
   h. Liquid Molecular Weight: 188
   i. Vapor Molecular Weight: 130

j. Chemical Components Information N/A

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(a)

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

S FLSO Fwd Machinery Space Storage Tank 2

I. *Tank Identification* (*Use a separate form for each tank*).

1. Applicant's Name: Excelerate Liquefaction Operations (Port Lavaca), LLC
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. SFLSOFOTK2 4. Emission Point No. SFLSOFOTK2
5. FIN ______ CIN ______
6. Status: New tank [x] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. *Tank Physical Characteristics* NOTE: Tank dimensions are estimated, for potential emission purposes only. Actual dimensions TBD.

1. Dimensions
   - a. Shell Height : 38.0 ft.
   - b. Diameter: 38.0 ft.
   - c. Maximum Liquid Height : 38.0 ft.
   - d. Nominal Capacity or Working Volume: 322,287 gallons.
   - e. Turnovers per year: 0.74
   - f. Net Throughput : 238,099 gallons/year.
   - g. Maximum Filling Rate: N/A gallons/hour.
2. Paint Characteristics
   - a. Shell Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe Unknown)
   - b. Shell Condition : Good [x] Poor [ ]
   - c. Roof Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe Unknown)
   - d. Roof Condition : Good [x] Poor [ ]
3. Roof Characteristics
   - a. Roof Type: Dome [ ] Cone [x]
   - b. Roof Height: Unknown ft. (*not including shell height)*
   - c. Radius (*Dome Roof Only*): N/A ft.
   - d. Slope (*Cone Roof Only*): 0.0625 ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve	N/A	N/A	N/A	N/A
Pressure Vent Valve	1	0.03		Atmosphere
Vacuum Vent Valve	1		-0.03	
Open Vent Valve	N/A			N/A

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ____________________ Tank No. SFLSOFOTK2

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [ ] Petroleum Distillates [x] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [x] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ____________________
   b. CAS Number: ____________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ___________
4. Multiple Component Information
   a. Mixture Name: Distillate fuel oil No. 2
   b. Average Liquid Surface Temperature: 73.50 °F.
   c. Minimum Liquid Surface Temperature: 60.93 °F.
   d. Maximum Liquid Surface Temperature: 85.42 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 0.0101 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 0.0067 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 0.0142 psia.
   h. Liquid Molecular Weight: 188
   i. Vapor Molecular Weight: 130

j. Chemical Components Information N/A

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

HORIZONTAL FIXED ROOF STORAGE TANK SUMMARY
N FLSO Aft Machinery Space Service Tank 1

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: Excelerate Liquefaction Operations (Port Lavaca), LLC
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. NFLSOFOTK5 4. Emission Point No. NFLSOFOTK5
5. FIN ______ CIN ______
6. Status: New tank [x] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics*** Note: Tank dimensions are estimated, for potential emission purposes only. Actual dimensions TBD.

1. Dimensions
   a. Shell Length : 11.3 ft.
   b. Diameter: 5.6 ft.
   c. Nominal Capacity or Working Volume: 2,113 gallons.
   d. Turnovers per year: 6.0
   e. Net Throughput : 12,610 gallons/year.
   f. Maximum Filling Rate: N/A gallons/hour.
   g. Is the tank underground? Yes [ ] No [x]
2. Paint Characteristics
   a. Shell Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ]
   Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   b. Shell Condition : Good [x] Poor [ ]

3. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve	N/A	N/A	N/A	N/A
Pressure Vent Valve	1	0.03		Atmosphere
Vacuum Vent Valve	1		-0.03	
Open Vent Valve	N/A			N/A

Permit No. ____________________ Tank No. NFLSOFOTK5

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [ ] Petroleum Distillates [x] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [x] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ____________________
   b. CAS Number: ____________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ____________
4. Multiple Component Information
   a. Mixture Name: Distillate fuel oil No. 2
   b. Average Liquid Surface Temperature: 73.50 °F.
   c. Minimum Liquid Surface Temperature: 60.93 °F.
   d. Maximum Liquid Surface Temperature: 85.42 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 0.0101 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 0.0067 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 0.0142 psia.
   h. Liquid Molecular Weight: 188
   i. Vapor Molecular Weight: 130

j. Chemical Components Information N/A

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(b)

HORIZONTAL FIXED ROOF STORAGE TANK SUMMARY
N FLSO Fwd Machinery Space Service Tank 1

I. ***Tank Identification*** *(Use a separate form for each tank)*.

1. Applicant's Name: Excelerate Liquefaction Operations (Port Lavaca), LLC
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. NFLSOFOTK3 4. Emission Point No. NFLSOFOTK3
5. FIN ______ CIN ______
6. Status: New tank [x] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics*** Note: Tank dimensions are estimated, for potential emission purposes only. Actual dimensions TBD.

1. Dimensions
   a. Shell Length : 22.1 ft.
   b. Diameter: 11.0 ft.
   c. Nominal Capacity or Working Volume: 15,850 gallons.
   d. Turnovers per year: 15.0
   e. Net Throughput : 238,099 gallons/year.
   f. Maximum Filling Rate: N/A gallons/hour.
   g. Is the tank underground? Yes [ ] No [x]
2. Paint Characteristics
   a. Shell Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   b. Shell Condition : Good [x] Poor [ ]

3. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve	N/A	N/A	N/A	N/A
Pressure Vent Valve	1	0.03		Atmosphere
Vacuum Vent Valve	1		-0.03	
Open Vent Valve	N/A			N/A

Permit No. ____________________ Tank No. NFLSOFOTK3

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [ ] Petroleum Distillates [x] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [x] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ____________________
   b. CAS Number: ____________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ____________
4. Multiple Component Information
   a. Mixture Name: Distillate fuel oil No. 2
   b. Average Liquid Surface Temperature: 73.50 °F.
   c. Minimum Liquid Surface Temperature: 60.93 °F.
   d. Maximum Liquid Surface Temperature: 85.42 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 0.0101 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 0.0067 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 0.0142 psia.
   h. Liquid Molecular Weight: 188
   i. Vapor Molecular Weight: 130

j. Chemical Components Information N/A

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(b)

HORIZONTAL FIXED ROOF STORAGE TANK SUMMARY
N FLSO Fwd Machinery Space Service Tank 2

I. ***Tank Identification*** *(Use a separate form for each tank).*

1. Applicant's Name: Excelerate Liquefaction Operations (Port Lavaca), LLC
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. NFLSOFOTK4 4. Emission Point No. NFLSOFOTK4
5. FIN _____ CIN _____
6. Status: New tank [x] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) _____

II. ***Tank Physical Characteristics*** Note: Tank dimensions are estimated, for potential emission purposes only. Actual dimensions TBD.

1. Dimensions
   a. Shell Length : 22.1 ft.
   b. Diameter: 11.0 ft.
   c. Nominal Capacity or Working Volume: 15,850 gallons.
   d. Turnovers per year: 15.0
   e. Net Throughput : 238,099 gallons/year.
   f. Maximum Filling Rate: N/A gallons/hour.
   g. Is the tank underground? Yes [ ] No [x]
2. Paint Characteristics
   a. Shell Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe _____)
   b. Shell Condition : Good [x] Poor [ ]

3. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve	N/A	N/A	N/A	N/A
Pressure Vent Valve	1	0.03		Atmosphere
Vacuum Vent Valve	1		-0.03	
Open Vent Valve	N/A			N/A

Permit No. ____________________ Tank No. NFLSOFOTK4

III. *Liquid Properties of Stored Material*

1. Chemical Category: Organic Liquids [ ] Petroleum Distillates [x] Crude Oils [ ]
2. Single or Multi-Component Liquid
   Single [ ] *Complete Section III.3*
   Multiple [x] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ____________________
   b. CAS Number: ____________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ____________
4. Multiple Component Information
   a. Mixture Name: Distillate fuel oil No. 2
   b. Average Liquid Surface Temperature: 73.50 °F.
   c. Minimum Liquid Surface Temperature: 60.93 °F.
   d. Maximum Liquid Surface Temperature: 85.42 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 0.0101 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 0.0067 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 0.0142 psia.
   h. Liquid Molecular Weight: 188
   i. Vapor Molecular Weight: 130

j. Chemical Components Information N/A

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

HORIZONTAL FIXED ROOF STORAGE TANK SUMMARY
Onshore Emergency Generator Service Tank 1

I. ***Tank Identification*** *(Use a separate form for each tank)*.

1. Applicant's Name: Excelerate Liquefaction Operations (Port Lavaca), LLC
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. OSFOTK1 4. Emission Point No. OSFOTK1
5. FIN ______ CIN ______
6. Status: New tank [x] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics*** Note: Tank dimensions are estimated, for potential emission purposes only. Actual dimensions TBD.

1. Dimensions
   a. Shell Length : 11.1 ft.
   b. Diameter: 5.5 ft.
   c. Nominal Capacity or Working Volume: 2,000 gallons.
   d. Turnovers per year: 10.7
   e. Net Throughput : 21,416 gallons/year.
   f. Maximum Filling Rate: N/A gallons/hour.
   g. Is the tank underground? Yes [ ] No [x]
2. Paint Characteristics
   a. Shell Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   b. Shell Condition : Good [x] Poor [ ]

3. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve	N/A	N/A	N/A	N/A
Pressure Vent Valve	1	0.03		Atmosphere
Vacuum Vent Valve	1		-0.03	
Open Vent Valve	N/A			N/A

Permit No. ____________________ Tank No. OSFOTK1

III. *Liquid Properties of Stored Material*

1. Chemical Category: Organic Liquids [ ] Petroleum Distillates [x] Crude Oils [ ]
2. Single or Multi-Component Liquid
   Single [ ] *Complete Section III.3*
   Multiple [x] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ____________________
   b. CAS Number: ____________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ____________
4. Multiple Component Information
   a. Mixture Name: Distillate fuel oil No. 2
   b. Average Liquid Surface Temperature: 73.50 °F.
   c. Minimum Liquid Surface Temperature: 60.93 °F.
   d. Maximum Liquid Surface Temperature: 85.42 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 0.0101 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 0.0067 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 0.0142 psia.
   h. Liquid Molecular Weight: 188
   i. Vapor Molecular Weight: 130

j. Chemical Components Information N/A

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(b)

02-95

HORIZONTAL FIXED ROOF STORAGE TANK SUMMARY
Onshore Emergency Generator Service Tank 2

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: Excelerate Liquefaction Operations (Port Lavaca), LLC
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. OSFOTK2 4. Emission Point No. OSFOTK2
5. FIN ______ CIN ______
6. Status: New tank [x] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics*** Note: Tank dimensions are estimated, for potential emission purposes only. Actual dimensions TBD.

1. Dimensions
   a. Shell Length : 11.1 ft.
   b. Diameter: 5.5 ft.
   c. Nominal Capacity or Working Volume: 2,000 gallons.
   d. Turnovers per year: 10.7
   e. Net Throughput : 21,416 gallons/year.
   f. Maximum Filling Rate: N/A gallons/hour.
   g. Is the tank underground? Yes [ ] No [x]
2. Paint Characteristics
   a. Shell Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   b. Shell Condition : Good [x] Poor [ ]

3. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve	N/A	N/A	N/A	N/A
Pressure Vent Valve	1	0.03		Atmosphere
Vacuum Vent Valve	1		-0.03	
Open Vent Valve	N/A			N/A

Permit No. ____________________ Tank No. OSFOTK2

III. *Liquid Properties of Stored Material*

1. Chemical Category: Organic Liquids [ ] Petroleum Distillates [x] Crude Oils [ ]
2. Single or Multi-Component Liquid
   Single [ ] *Complete Section III.3*
   Multiple [x] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ____________________
   b. CAS Number: ____________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ____________
4. Multiple Component Information
   a. Mixture Name: Distillate fuel oil No. 2
   b. Average Liquid Surface Temperature: 73.50 °F.
   c. Minimum Liquid Surface Temperature: 60.93 °F.
   d. Maximum Liquid Surface Temperature: 85.42 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 0.0101 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 0.0067 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 0.0142 psia.
   h. Liquid Molecular Weight: 188
   i. Vapor Molecular Weight: 130

j. Chemical Components Information N/A

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

HORIZONTAL FIXED ROOF STORAGE TANK SUMMARY

Onshore Fire Pump Service Tank 1

I. ***Tank Identification*** *(Use a separate form for each tank*).

1. Applicant's Name: Excelerate Liquefaction Operations (Port Lavaca), LLC
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. OSFOTK3 4. Emission Point No. OSFOTK3
5. FIN ______ CIN ______
6. Status: New tank [x] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics*** Note: Tank dimensions are estimated, for potential emission purposes only. Actual dimensions TBD.

1. Dimensions
   a. Shell Length : 7.0 ft.
   b. Diameter: 3.5 ft.
   c. Nominal Capacity or Working Volume: 500 gallons.
   d. Turnovers per year: 1.02
   e. Net Throughput : 510 gallons/year.
   f. Maximum Filling Rate: N/A gallons/hour.
   g. Is the tank underground? Yes [ ] No [x]
2. Paint Characteristics
   a. Shell Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   b. Shell Condition : Good [x] Poor [ ]

3. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve	N/A	N/A	N/A	N/A
Pressure Vent Valve	1	0.03		Atmosphere
Vacuum Vent Valve	1		-0.03	
Open Vent Valve	N/A			N/A

Permit No. ____________________ Tank No. OSFOTK3

III. *Liquid Properties of Stored Material*

1. Chemical Category: Organic Liquids [ ] Petroleum Distillates [x] Crude Oils [ ]
2. Single or Multi-Component Liquid
   Single [ ] *Complete Section III.3*
   Multiple [x] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ____________________
   b. CAS Number: ____________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ____________
4. Multiple Component Information
   a. Mixture Name: Distillate fuel oil No. 2
   b. Average Liquid Surface Temperature: 73.50 °F.
   c. Minimum Liquid Surface Temperature: 60.93 °F.
   d. Maximum Liquid Surface Temperature: 85.42 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 0.0101 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 0.0067 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 0.0142 psia.
   h. Liquid Molecular Weight: 188
   i. Vapor Molecular Weight: 130

j. Chemical Components Information N/A

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(b)

02-95

HORIZONTAL FIXED ROOF STORAGE TANK SUMMARY
S FLSO Aft Machinery Space Service Tank 1

I. ***Tank Identification*** *(Use a separate form for each tank*).

1. Applicant's Name: Excelerate Liquefaction Operations (Port Lavaca), LLC
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. SFLSOFOTK5 4. Emission Point No. SFLSOFOTK5
5. FIN ______ CIN ______
6. Status: New tank [x] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics*** Note: Tank dimensions are estimated, for potential emission purposes only. Actual dimensions TBD.

1. Dimensions
   - a. Shell Length : 11.3 ft.
   - b. Diameter: 5.6 ft.
   - c. Nominal Capacity or Working Volume: 2,113 gallons.
   - d. Turnovers per year: 6.0
   - e. Net Throughput : 12,610 gallons/year.
   - f. Maximum Filling Rate: N/A gallons/hour.
   - g. Is the tank underground? Yes [ ] No [x]
2. Paint Characteristics
   - a. Shell Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   - b. Shell Condition : Good [x] Poor [ ]

3. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve	N/A	N/A	N/A	N/A
Pressure Vent Valve	1	0.03		Atmosphere
Vacuum Vent Valve	1		-0.03	
Open Vent Valve	N/A			N/A

Permit No. ____________________ Tank No. SFLSOFOTK5

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [ ] Petroleum Distillates [x] Crude Oils [ ]
2. Single or Multi-Component Liquid
   Single [ ] *Complete Section III.3*
   Multiple [x] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ______________________________
   b. CAS Number: ______________
   c. Average Liquid Surface Temperature: ________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ______ psia.
   e. Liquid Molecular Weight: ________
4. Multiple Component Information
   a. Mixture Name: Distillate fuel oil No. 2
   b. Average Liquid Surface Temperature: 73.50 °F.
   c. Minimum Liquid Surface Temperature: 60.93 °F.
   d. Maximum Liquid Surface Temperature: 85.42 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 0.0101 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 0.0067 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 0.0142 psia.
   h. Liquid Molecular Weight: 188
   i. Vapor Molecular Weight: 130

j. Chemical Components Information N/A

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(b)

HORIZONTAL FIXED ROOF STORAGE TANK SUMMARY
S FLSO Fwd Machinery Space Service Tank 1

I. ***Tank Identification*** *(Use a separate form for each tank)*.

1. Applicant's Name: Excelerate Liquefaction Operations (Port Lavaca), LLC
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. SFLSOFOTK3 4. Emission Point No. SFLSOFOTK3
5. FIN ______ CIN ______
6. Status: New tank [x] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics*** Note: Tank dimensions are estimated, for potential emission purposes only. Actual dimensions TBD.

1. Dimensions
   a. Shell Length : 22.1 ft.
   b. Diameter: 11.0 ft.
   c. Nominal Capacity or Working Volume: 15,850 gallons.
   d. Turnovers per year: 15.0
   e. Net Throughput : 238,099 gallons/year.
   f. Maximum Filling Rate: N/A gallons/hour.
   g. Is the tank underground? Yes [ ] No [x]
2. Paint Characteristics
   a. Shell Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   b. Shell Condition : Good [x] Poor [ ]

3. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve	N/A	N/A	N/A	N/A
Pressure Vent Valve	1	0.03		Atmosphere
Vacuum Vent Valve	1		-0.03	
Open Vent Valve	N/A			N/A

Permit No. ____________________ Tank No. SFLSOFOTK3

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [ ] Petroleum Distillates [x] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [x] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ______________________
   b. CAS Number: ______________
   c. Average Liquid Surface Temperature: ________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ______ psia.
   e. Liquid Molecular Weight: ________
4. Multiple Component Information
   a. Mixture Name: Distillate fuel oil No. 2
   b. Average Liquid Surface Temperature: 73.50 °F.
   c. Minimum Liquid Surface Temperature: 60.93 °F.
   d. Maximum Liquid Surface Temperature: 85.42 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 0.0101 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 0.0067 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 0.0142 psia.
   h. Liquid Molecular Weight: 188
   i. Vapor Molecular Weight: 130

j. Chemical Components Information N/A

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(b)

02-95

HORIZONTAL FIXED ROOF STORAGE TANK SUMMARY
S FLSO Fwd Machinery Space Service Tank 2

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: Excelerate Liquefaction Operations (Port Lavaca), LLC
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. SFLSOFOTK4 4. Emission Point No. SFLSOFOTK4
5. FIN ______ CIN ______
6. Status: New tank [x] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics*** Note: Tank dimensions are estimated, for potential emission purposes only. Actual dimensions TBD.

1. Dimensions
   a. Shell Length : 22.1 ft.
   b. Diameter: 11.0 ft.
   c. Nominal Capacity or Working Volume: 15,850 gallons.
   d. Turnovers per year: 15.0
   e. Net Throughput : 238,099 gallons/year.
   f. Maximum Filling Rate: N/A gallons/hour.
   g. Is the tank underground? Yes [ ] No [x]
2. Paint Characteristics
   a. Shell Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   b. Shell Condition : Good [x] Poor [ ]

3. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve	N/A	N/A	N/A	N/A
Pressure Vent Valve	1	0.03		Atmosphere
Vacuum Vent Valve	1		-0.03	
Open Vent Valve	N/A			N/A

Permit No. ____________________ Tank No. SFLSOFOTK4

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [ ] Petroleum Distillates [x] Crude Oils [ ]
2. Single or Multi-Component Liquid
   Single [ ] *Complete Section III.3*
   Multiple [x] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ______________________________
   b. CAS Number: ________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: _______ psia.
   e. Liquid Molecular Weight: __________
4. Multiple Component Information
   a. Mixture Name: Distillate fuel oil No. 2
   b. Average Liquid Surface Temperature: 73.50 °F.
   c. Minimum Liquid Surface Temperature: 60.93 °F.
   d. Maximum Liquid Surface Temperature: 85.42 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 0.0101 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 0.0067 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 0.0142 psia.
   h. Liquid Molecular Weight: 188
   i. Vapor Molecular Weight: 130

j. Chemical Components Information N/A

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(d)

INTERNAL FLOATING ROOF STORAGE TANK SUMMARY

Onshore Hydrocarbon Condensate Storage Tank 1

I. ***Tank Identification*** *(Use a separate form for each tank)*.

1. Applicant's Name: Excelerate Liquefaction Operations (Port Lavaca), LLC
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. OSHCTK1 4. Emission Point No. OSHCTK1
5. FIN ______ CIN ______
6. Status: New tank [x] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics*** Note: Tank dimensions are estimated, for potential emission purposes only. Actual dimensions TBD.

1. Dimensions
   a. Shell Height : 28.2 ft.
   b. Diameter: 28.2 ft.
   c. Nominal Capacity or Tank Volume: 132,084 gallons.
   d. Turnovers per year: 141
   e. Net Throughput : 18,623,844 gallons/year.
   f. Maximum Pumping Rate: N/A gallons/hour. (*Use the higher of the maximum fill rate or maximum withdrawal rate.*)
   g. Self-Supporting Roof ? Yes [x] No [ ]
   h. Number of Columns: N/A
   i. Column Diameter: N/A ft.
2. Shell/Roof and Paint Characteristics
   a. Shell Condition : Light Rust [x] Dense Rust [ ] Gunite Lining [ ]
   b. Shell Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   c. Shell Condition : Good [x] Poor [ ]
   d. Roof Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   e. Roof Condition : Good [x] Poor [ ]
3. Rim-Seal System
   a. Primary Seal: Vapor-mounted [ ] Liquid-mounted [ ] Mechanical Shoe [x]
   b. Secondary Seal : Yes [x] No [ ]
4. Deck Characteristics
   a. Deck Type: Bolted [ ] Welded[x]
   b. Deck Construction (*Bolted Tanks Only*):
      - Continuous Sheet Construction 5 ft. wide [ ]
      - Continuous Sheet Construction 6 ft. wide [ ]
      - Continuous Sheet Construction 7 ft. wide [ ]
      - Rectangular Panel Construction 5 X 7.5 ft. wide [ ]
      - Rectangular Panel Construction 5 X 12 ft. wide [ ]
   c. Deck Seam Length (*Bolted Tanks Only*): ____ ft.
5. Roof Fitting Loss Factor: N/A lb-mole/year

   Based upon Typical [ ] Controlled [ ] or Actual [ ] fittings

   Complete Section IV, Fittings Information, to record fittings count used to calculate the roof fitting loss factor.

Permit No. ______________________ Tank No. OSHCTK1

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [x] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [x] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ______________________
   b. CAS Number: ______________
   c. Average Liquid Surface Temperature: ________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: _______ psia.
   e. Liquid Molecular Weight: __________
4. Multiple Component Information
   a. Mixture Name: Condensate
   b. Average Liquid Surface Temperature: 73.50 °F.
   c. Minimum Liquid Surface Temperature: 60.93 °F.
   d. Maximum Liquid Surface Temperature: 85.42 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 8.2471 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 7.0536 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 9.2280 psia.
   h. Liquid Molecular Weight: 87.64
   i. Vapor Molecular Weight: 64.3127

j. Chemical Components Information See attached page 4.

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total VaporWeight(typical)	Molecular Weight

Permit No. ____________________ Tank No. OSHCTK1

IV. *Fittings Information*

Fitting Type	Fitting Status	Quantity	Deck fitting loss factor K_F	Quantity X K_F
Access Hatch (24-in. Diam.)	Bolted Cover, Gasketed	1	1.6	1.6
Access Hatch (24-in. Diam.)	Unbolted Cover, Gasketed		11	
Access Hatch (24-in. Diam.)	Unbolted Cover, Ungasketed		25	
Automatic Gauge Float Well	Bolted Cover, Gasketed	1	5.1	5.1
Automatic Gauge Float Well	Unbolted Cover, Gasketed		15	
Automatic Gauge Float Well	Unbolted Cover, Ungasketed		28	
Column Well (24-in.Diam.)	Built-Up Col. -Sliding Cover, Gask.		33	
.Column Well (24-in.Diam.)	Built-Up Col. -Sliding Cover, Ungask.		47	
Column Well (24-in.Diam.)	Pipe Col. -Flex. Fabric Sleeve Seal		10	
Column Well (24-in.Diam.)	Pipe Col. -Sliding Cover, Gask.		19	
Column Well (24-in.Diam.)	Pipe Col. -Sliding Cover, Ungask.		32	
Ladder Well (36-in. Diam.)	Sliding Cover, Ungasketed		76	
Ladder Well (36-in. Diam.)	Sliding Cover, Gasketed		56	
Roof Leg or Hanger Well	Adjustable	9	7.9	71.1
Roof Leg or Hanger Well	Fixed		0	0
Sample Pipe or Well (24-in. Diam.)	Slit Fabric Seal 10% Open	1	12	12
Sample Pipe or Well (24-in. Diam.)	Slotted Pipe-Sliding Cover, Gask.		44	
Sample Pipe or Well (24-in. Diam.)	Slotted Pipe-Sliding Cover, Ungask.		57	
Stub Drain (1-in. Diam.)			1.2	
Vacuum Breaker (10-in. Diam.)	Weighted Mech. Actuation, Gask.	1	0.7	0.7
Vacuum Breaker (10-in. Diam.)	Weighted Mech. Actuation, Ungask.		0.9	
			Total deck fitting loss factor, lb-mole/year	90.5

Permit No. ______________ Tank No. OSHCTK1

III. Liquid Properties of Stored Material

j. Chemical Components Information				
Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight
Propane	74-98-6	0.35	7.67	44.10
i-Butane	75-28-5	2.36	18.46	58.12
n-Butane	106-97-8	4.74	26.27	58.12
i-Pentane	78-78-4	8.64	19.31	72.15
n-Pentane	109-66-0	6.97	10.57	72.15
n-Hexane	110-54-3	27.09	12.08	86.18
Benzene	71-43-2	1.97	0.55	78.11
n-Heptane	142-82-5	29.84	4.49	100.20
n-Octane	111-65-9	17.39	0.60	114.23
n-Nonane	111-84-2	0.47	0.01	128.26
n-Decane	124-18-5	0.18	0.00	142.28

TABLE 7(d)

INTERNAL FLOATING ROOF STORAGE TANK SUMMARY

Onshore Hydrocarbon Condensate Storage Tank 2

I. ***Tank Identification*** *(Use a separate form for each tank).*

1. Applicant's Name: Excelerate Liquefaction Operations (Port Lavaca), LLC
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. OSHCTK2   4. Emission Point No. OSHCTK2
5. FIN ______   CIN ______
6. Status: New tank [x] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics*** Note: Tank dimensions are estimated, for potential emission purposes only. Actual dimensions TBD.

1. Dimensions
   a. Shell Height : 28.2 ft.
   b. Diameter: 28.2 ft.
   c. Nominal Capacity or Tank Volume: 132,084 gallons.
   d. Turnovers per year: 141
   e. Net Throughput : 18,623,844 gallons/year.
   f. Maximum Pumping Rate: N/A gallons/hour. (*Use the higher of the maximum fill rate or maximum withdrawal rate.*)
   g. Self-Supporting Roof ? Yes [x] No [ ]
   h. Number of Columns: N/A
   i. Column Diameter: N/A ft.
2. Shell/Roof and Paint Characteristics
   a. Shell Condition : Light Rust [x] Dense Rust [ ] Gunite Lining [ ]
   b. Shell Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   c. Shell Condition : Good [x] Poor [ ]
   d. Roof Color/Shade : White/White [x] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   e. Roof Condition : Good [x] Poor [ ]
3. Rim-Seal System
   a. Primary Seal: Vapor-mounted [ ] Liquid-mounted [ ] Mechanical Shoe [x]
   b. Secondary Seal : Yes [x] No [ ]
4. Deck Characteristics
   a. Deck Type: Bolted [ ] Welded [x]
   b. Deck Construction (*Bolted Tanks Only*):
      - Continuous Sheet Construction 5 ft. wide [ ]
      - Continuous Sheet Construction 6 ft. wide [ ]
      - Continuous Sheet Construction 7 ft. wide [ ]
      - Rectangular Panel Construction 5 X 7.5 ft. wide [ ]
      - Rectangular Panel Construction 5 X 12 ft. wide [ ]
   c. Deck Seam Length (*Bolted Tanks Only*): ____ ft.
5. Roof Fitting Loss Factor: N/A lb-mole/year

   Based upon Typical [ ] Controlled [ ] or Actual [ ] fittings

   Complete Section IV, Fittings Information, to record fittings count used to calculate the roof fitting loss factor.

Permit No. ______________________ Tank No. OSHCTK2

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [x] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid
   Single [ ] *Complete Section III.3*
   Multiple [x] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ______________________
   b. CAS Number: ______________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ____________
4. Multiple Component Information
   a. Mixture Name: Condensate
   b. Average Liquid Surface Temperature: 73.50 °F.
   c. Minimum Liquid Surface Temperature: 60.93 °F.
   d. Maximum Liquid Surface Temperature: 85.42 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 8.2471 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 7.0536 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 9.2280 psia.
   h. Liquid Molecular Weight: 87.64
   i. Vapor Molecular Weight: 64.3127

j. Chemical Components Information See attached page 4.

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total VaporWeight(typical)	Molecular Weight

Permit No. ____________________ Tank No. OSHCTK2

IV. *Fittings Information*

Fitting Type	Fitting Status	Quantity	Deck fitting loss factor K_F	Quantity X K_F
Access Hatch (24-in. Diam.)	Bolted Cover, Gasketed	1	1.6	1.6
Access Hatch (24-in. Diam.)	Unbolted Cover, Gasketed		11	
Access Hatch (24-in. Diam.)	Unbolted Cover, Ungasketed		25	
Automatic Gauge Float Well	Bolted Cover, Gasketed	1	5.1	5.1
Automatic Gauge Float Well	Unbolted Cover, Gasketed		15	
Automatic Gauge Float Well	Unbolted Cover, Ungasketed		28	
Column Well (24-in.Diam.)	Built-Up Col. -Sliding Cover, Gask.		33	
.Column Well (24-in.Diam.)	Built-Up Col. -Sliding Cover, Ungask.		47	
Column Well (24-in.Diam.)	Pipe Col. -Flex. Fabric Sleeve Seal		10	
Column Well (24-in.Diam.)	Pipe Col. -Sliding Cover, Gask.		19	
Column Well (24-in.Diam.)	Pipe Col. -Sliding Cover, Ungask.		32	
Ladder Well (36-in. Diam.)	Sliding Cover, Ungasketed		76	
Ladder Well (36-in. Diam.)	Sliding Cover, Gasketed		56	
Roof Leg or Hanger Well	Adjustable	9	7.9	71.1
Roof Leg or Hanger Well	Fixed		0	0
Sample Pipe or Well (24-in. Diam.)	Slit Fabric Seal 10% Open	1	12	12
Sample Pipe or Well (24-in. Diam.)	Slotted Pipe-Sliding Cover, Gask.		44	
Sample Pipe or Well (24-in. Diam.)	Slotted Pipe-Sliding Cover, Ungask.		57	
Stub Drain (1-in. Diam.)			1.2	
Vacuum Breaker (10-in. Diam.)	Weighted Mech. Actuation, Gask.	1	0.7	0.7
Vacuum Breaker (10-in. Diam.)	Weighted Mech. Actuation, Ungask.		0.9	
			Total deck fitting loss factor, lb-mole/year	90.5

Table 7(D) INTERNAL FLOATING ROOF TANK SUMMARY
Page 4

Permit No. ____________ Tank No. OSHCTK2

III. Liquid Properties of Stored Material

j. Chemical Components Information				
Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight
Propane	74-98-6	0.35	7.67	44.10
i-Butane	75-28-5	2.36	18.46	58.12
n-Butane	106-97-8	4.74	26.27	58.12
i-Pentane	78-78-4	8.64	19.31	72.15
n-Pentane	109-66-0	6.97	10.57	72.15
n-Hexane	110-54-3	27.09	12.08	86.18
Benzene	71-43-2	1.97	0.55	78.11
n-Heptane	142-82-5	29.84	4.49	100.20
n-Octane	111-65-9	17.39	0.60	114.23
n-Nonane	111-84-2	0.47	0.01	128.26
n-Decane	124-18-5	0.18	0.00	142.28

TABLE 7(e)

CHEMICAL DATA INFORMATION

(for Onshore Hydrocarbon Condensate Storage Tanks, OSHCTK1 and OSHCTK2)

I. ***Chemical Identification*** *(Use a separate form for each chemical not in the Tanks 2.0 database)*.

1. Chemical Name: Butane (-i)
2. CAS Number: 75-28-5
3. Category: Crude Oil [ ] Petroleum Distillates [ ] Organic Liquids [x]
4. Molecular Weight: 58.12
5. Liquid Density at 60°F (lbs/gal): 4.60

II. ***Vapor Pressure Information*** *(Fill in one or more options completely.)*

Option 1: *Enter Vapor Pressure (psia) for each temperature.*

40°F: ____________ 50°F: ____________
60°F: ____________ 70°F: ____________
80°F: ____________ 90°F: ____________
100°F: ____________

Option 2: *Enter Constants for Antoines's Equation (using °C).*
A: ____________ B: ____________ C: ____________

Option 3: *Enter Constants for Antoines's Equation (using °K).*
A: 21539.3452 B: 7.186

Option 4: *Enter Reid Vapor Pressure (psia) and ASTM slope.* **(This option for Crude Oils and Petroleum Distillates Only)**

Reid Vapor Pressure (psia) : ____________ **(Crude Oil, Petroleum Distillates)**
ASTM Slope : ____________ **(Petroleum Distillates only)**

Provide Source of Vapor Pressure Data.

Antoine's coefficients are based on data in 62nd and 78th ed. of CRC Handbook and Physics

If Options above are not used, please provide alternate data used and data Source.

TABLE 7(e)

CHEMICAL DATA INFORMATION

(for Onshore Hydrocarbon Condensate Storage Tanks, OSHCTK1 and OSHCTK2)

I. ***Chemical Identification*** *(Use a separate form for each chemical not in the Tanks 2.0 database).*

1. Chemical Name: Butane (-n)
2. CAS Number: 106-97-8
3. Category: Crude Oil [ ] Petroleum Distillates [ ] Organic Liquids [x]
4. Molecular Weight: 58.12
5. Liquid Density at 60°F (lbs/gal): 4.78

II. ***Vapor Pressure Information*** *(Fill in one or more options completely.)*

Option 1: *Enter Vapor Pressure (psia) for each temperature.*

40°F: ____________ 50°F: ____________
60°F: ____________ 70°F: ____________
80°F: ____________ 90°F: ____________
100°F: ____________

Option 2: *Enter Constants for Antoines's Equation (using °C).*
A: ____________ B: ____________ C: ____________

Option 3: *Enter Constants for Antoines's Equation (using °K).*
A: 21358.2232 B: 7.356

Option 4: *Enter Reid Vapor Pressure (psia) and ASTM slope.* **(This option for Crude Oils and Petroleum Distillates Only)**

Reid Vapor Pressure (psia) : ____________ **(Crude Oil, Petroleum Distillates)**
ASTM Slope : ____________ **(Petroleum Distillates only)**

Provide Source of Vapor Pressure Data.

Antoine's coefficients are based on data in 62nd and 78th ed. of CRC Handbook and Physics

If Options above are not used, please provide alternate data used and data Source.

TABLE 7(e)

CHEMICAL DATA INFORMATION

(for Onshore Hydrocarbon Condensate Storage Tanks, OSHCTK1 and OSHCTK2)

I. ***Chemical Identification*** *(Use a separate form for each chemical not in the Tanks 2.0 database).*

1. Chemical Name: Propane
2. CAS Number: 74-98-6
3. Category: Crude Oil [ ] Petroleum Distillates [ ] Organic Liquids [x]
4. Molecular Weight: 44.10
5. Liquid Density at 60°F (lbs/gal): 4.22

II. ***Vapor Pressure Information*** *(Fill in one or more options completely.)*

Option 1: *Enter Vapor Pressure (psia) for each temperature.*

40°F: ______ 50°F: ______
60°F: ______ 70°F: ______
80°F: ______ 90°F: ______
100°F: ______

Option 2: *Enter Constants for Antoines's Equation (using °C).*

A: ______ B: ______ C: ______

Option 3: *Enter Constants for Antoines's Equation (using °K).*

A: 18971.8553 B: 7.177

Option 4: *Enter Reid Vapor Pressure (psia) and ASTM slope.* **(This option for Crude Oils and Petroleum Distillates Only)**

Reid Vapor Pressure (psia) : ______ **(Crude Oil, Petroleum Distillates)**
ASTM Slope : ______ **(Petroleum Distillates only)**

Provide Source of Vapor Pressure Data.

Antoine's coefficients are based on vapor pressure data in Perry's Chemical Engineers' Handbook, 8th Ed., Table 2-8

If Options above are not used, please provide alternate data used and data Source.

North FLSO Cold Flare

TABLE 8

FLARE SYSTEMS

Number from Flow Diagram NFLSOCF	Manufacturer & Model No. (if available) TBD

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Max.
Waste gas is from routine and emergency release of cryogenic vapor relief valves. Composition is assumed to be that of "Net LNG to Storage." See Appendix B for composition details.		(scfm [68°F,14.7 psia])	(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])
	1.	106	106	40,977
	2.			
	3.			
	4.			
	5.			
	6.			
	7.			
	8.			
% of time this condition occurs		N/A	+97%	N/A

	Flow Rate (scfm [68°F, 14.7 psia])		Temp. °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	106	40,977	TBD	TBD
Fuel Added to Gas Steam	N/A	N/A	N/A	N/A

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [70°F & 14.7 psia]) per pilot
N/A	1	Natural gas	68

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

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

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

Flare Height (ft) 403.5	Flare tip inside diameter (ft) TBD
Capital Installed Cost $TBD	Annual Operating Cost $TBD

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

North FLSO Tank Relief and Maintenance Flare

TABLE 8

FLARE SYSTEMS

Number from Flow Diagram NFLSOTRMF	Manufacturer & Model No. (if available) TBD

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Max.
Waste gas is from maintenance activities related to FLSO LNG tank inspections, and from LNGC gas-in and cooldown activities. Gas composition will vary. See Appendix B for composition details.		(scfm [68°F,14.7 psia])	(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])
	1.	TBD	TBD	TBD
	2.			
	3.			
	4.			
	5.			
	6.			
	7.			
	8.			
% of time this condition occurs		TBD	TBD	TBD

	Flow Rate (scfm [68°F, 14.7 psia])		Temp. °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	TBD	TBD	TBD	TBD
Fuel Added to Gas Steam	N/A	N/A	N/A	N/A

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [70°F & 14.7 psia]) per pilot
N/A	1	Natural gas	TBD

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

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

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

Flare Height (ft) 403.5	Flare tip inside diameter (ft) TBD
Capital Installed Cost $TBD	Annual Operating Cost $TBD

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

North FLSO Warm Flare

TABLE 8

FLARE SYSTEMS

Number from Flow Diagram NFLSOWF	Manufacturer & Model No. (if available) TBD

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Max.
Waste gas is from routine and emergency release of cryogenic vapor relief valves. Composition is assumed to be that of "Treated Gas." See Appendix B for composition details.		(scfm [68°F,14.7 psia])	(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])
	1.	106	106	29,285
	2.			
	3.			
	4.			
	5.			
	6.			
	7.			
	8.			
% of time this condition occurs		N/A	100%	N/A

	Flow Rate (scfm [68°F, 14.7 psia])		Temp. °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	106	29,285	TBD	TBD
Fuel Added to Gas Steam	N/A	N/A	N/A	N/A

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [70°F & 14.7 psia]) per pilot
N/A	1	Natural gas	68

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

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

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

Flare Height (ft) 403.5	Flare tip inside diameter (ft) TBD
Capital Installed Cost $ TBD	Annual Operating Cost $ TBD

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

05/96

Onshore Ground Flare

TABLE 8

FLARE SYSTEMS

Number from Flow Diagram OSGF	Manufacturer & Model No. (if available) TBD

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Max.
Waste gas is from controlled depressurization of feed gas pre-treatment system. Composition is assumed to be that "Feed Gas." See Appendix B for composition details.		(scfm [68°F,14.7 psia])	(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])
	1.	N/A	5,977	N/A
	2.			
	3.			
	4.			
	5.			
	6.			
	7.			
	8.			
% of time this condition occurs		N/A	0.1%	N/A

	Flow Rate (scfm [68°F, 14.7 psia])		Temp. °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	N/A	N/A	TBD	TBD
Fuel Added to Gas Steam	N/A	N/A	N/A	N/A

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

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

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

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

Flare Height (ft) 45.9	Flare tip inside diameter (ft) TBD
Capital Installed Cost $TBD	Annual Operating Cost $TBD

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

South FLSO Cold Flare

TABLE 8

FLARE SYSTEMS

Number from Flow Diagram SFLSOCF	Manufacturer & Model No. (if available) TBD

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Max.
Waste gas is from routine and emergency release of cryogenic vapor relief valves. Composition is assumed to be that of "Net LNG to Storage." See Appendix B for composition details.		(scfm [68°F,14.7 psia])	(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])
	1.	106	106	40,977
	2.			
	3.			
	4.			
	5.			
	6.			
	7.			
	8.			
% of time this condition occurs		N/A	+97%	N/A

	Flow Rate (scfm [68°F, 14.7 psia])		Temp. °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	106	40,977	TBD	TBD
Fuel Added to Gas Steam	N/A	N/A	N/A	N/A

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [70°F & 14.7 psia]) per pilot
N/A	1	Natural gas	68

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

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

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

Flare Height (ft) 403.5	Flare tip inside diameter (ft) TBD
Capital Installed Cost $TBD	Annual Operating Cost $TBD

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

South FLSO Tank Relief and Maintenance Flare

TABLE 8

FLARE SYSTEMS

Number from Flow Diagram SFLSOTRMF	Manufacturer & Model No. (if available) TBD

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Max.
Waste gas is from maintenance activities related to FLSO LNG tank inspections, and from LNGC gas-in and cooldown activities. Gas composition will vary. See Appendix B for composition details.		(scfm [68°F,14.7 psia])	(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])
	1.	TBD	TBD	TBD
	2.			
	3.			
	4.			
	5.			
	6.			
	7.			
	8.			
% of time this condition occurs		TBD	TBD	TBD

	Flow Rate (scfm [68°F, 14.7 psia])		Temp. °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	TBD	TBD	TBD	TBD
Fuel Added to Gas Steam	N/A	N/A	N/A	N/A

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [70°F & 14.7 psia]) per pilot
N/A	1	Natural gas	TBD

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

	Number of Jet Streams	Diameter of Steam Jets (inches)	Design basis for steam injected (lb steam/lb hydrocarbon)
For Stream Injection	N/A	N/A	N/A

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

Flare Height (ft) 403.5	Flare tip inside diameter (ft) TBD
Capital Installed Cost $TBD	Annual Operating Cost $TBD

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

South FLSO Warm Flare

TABLE 8

FLARE SYSTEMS

Number from Flow Diagram SFLSOWF	Manufacturer & Model No. (if available) TBD

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Max.
Waste gas is from routine and emergency release of cryogenic vapor relief valves. Composition is assumed to be that of "Treated Gas." See Appendix B for composition details.		(scfm [68°F,14.7 psia])	(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])
	1.	106	106	29,285
	2.			
	3.			
	4.			
	5.			
	6.			
	7.			
	8.			
% of time this condition occurs		N/A	100%	N/A

	Flow Rate (scfm [68°F, 14.7 psia])		Temp. °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	106	29,285	TBD	TBD
Fuel Added to Gas Steam	N/A	N/A	N/A	N/A

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [70°F & 14.7 psia]) per pilot
N/A	1	Natural gas	68

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

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

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

Flare Height (ft) 403.5	Flare tip inside diameter (ft) TBD
Capital Installed Cost $TBD	Annual Operating Cost $TBD

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

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data

Manufacturer:	Model No.	Serial No.	Manufacture Date:
Cummins	KTA50-DM1	N/A	N/A
Rebuilds Date:	**No. of Cylinders:**	**Compression Ratio:**	**EPN:**
N/A	16	13.9:1	NFLSOEGN

Application: ☐ Gas Compression ☐ Electric Generation ☐ Refrigeration ☒ Emergency/Stand by

☒ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☐ Fuel Injected

☒ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☒ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☐ Rich Burn

Ignition/Injection Timing: Fixed: Variable:

Manufacture Horsepower Rating: 1729 Proposed Horsepower Rating: 1729

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (^{o}F)	Exit Velocity (FPS)
65.1	1.6	835	73

II. Fuel Data

Type of Fuel: ☐ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☒ Diesel

Fuel Consumption (BTU/bhp-hr): 6651	Heat Value: 19536 Btu (HHV)	18378 Btu/lb (LHV)

Sulfur Content (grains/100 scf - weight %): 0.0015 weight %

III. Emission Factors (Before Control)

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.77		2.61		0.0046		0.97		0.00024		0.15	

Source of Emission Factors: ☐ Manufacturer Data ☒ AP-42 ☒ Other (specify): NSPS IIII, AP-42 (CH2O)

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.77		2.61		0.0046		0.97		0.00024		0.15	

Method of Emission Control: ☐ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):________________________________

Note: *Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☒ Yes ☐ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☒ MACT ZZZZ ☒ NSPS IIII ☐ Title 30 Chapter 117 - List County: ____________________

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data			
Manufacturer: MAN	Model No. 12V32/40	Serial No. N/A	Manufacture Date: N/A
Rebuilds Date: N/A	No. of Cylinders: 12	Compression Ratio: N/A	EPN: NESGEN1

Application: ☐ Gas Compression ☒ Electric Generation ☐ Refrigeration ☐ Emergency/Stand by

☒ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☐ Fuel Injected

☒ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☒ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☐ Rich Burn

Ignition/Injection Timing: Fixed: Variable:

Manufacture Horsepower Rating**:** 7720 | Proposed Horsepower Rating: 7720

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (°F)	Exit Velocity (FPS)
180.9	3.9	590	56

II. Fuel Data

Type of Fuel: ☐ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☒ Diesel

Fuel Consumption (BTU/bhp-hr): 6105 | Heat Value: 19536 Btu (HHV) | 18378 Btu/lb (LHV)

Sulfur Content (grains/100 scf - weight %): 0.0015 weight %

III. Emission Factors (Before Control)

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
1.80		2.98		0.0043		0.97		0.00022		0.11	

Source of Emission Factors: ☐ Manufacturer Data ☒ AP-42 ☒ Other (specify): NSPS Subpart IIII, AP-42 (CH2O)

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
1.80		2.98		0.0043		0.97		0.00022		0.11	

Method of Emission Control: ☐ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):________________________________

Note: *Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☒ Yes ☐ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☒ MACT ZZZZ ☒ NSPS IIII ☐ Title 30 Chapter 117 - List County: ____________________

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data			
Manufacturer: MAN	Model No. 12V32/40	Serial No. N/A	Manufacture Date: N/A
Rebuilds Date: N/A	No. of Cylinders: 12	Compression Ratio: N/A	EPN: NESGEN2

Application: ☐ Gas Compression ☒ Electric Generation ☐ Refrigeration ☐ Emergency/Stand by

☒ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☐ Fuel Injected

☒ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☒ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☐ Rich Burn

Ignition/Injection Timing: Fixed: Variable:

Manufacture Horsepower Rating: 7720 Proposed Horsepower Rating: 7720

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (^{o}F)	Exit Velocity (FPS)
180.9	3.9	590	56

II. Fuel Data

Type of Fuel: ☐ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☒ Diesel

Fuel Consumption (BTU/bhp-hr): 6105 Heat Value: 19536 Btu (HHV) 18378 Btu/lb (LHV)

Sulfur Content (grains/100 scf - weight %): 0.0015 weight %

III. Emission Factors (Before Control)

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
1.80		2.98		0.0043		0.97		0.00022		0.11	

Source of Emission Factors: ☐ Manufacturer Data ☒ AP-42 ☒ Other (specify): NSPS Subpart IIII, AP-42 (CH2O)

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
1.80		2.98		0.0043		0.97		0.00022		0.11	

Method of Emission Control: ☐ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):______________________________

Note: *Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☒ Yes ☐ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☒ MACT ZZZZ ☒ NSPS IIII ☐ Title 30 Chapter 117 - List County: ____________________

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data			
Manufacturer: Cummins	Model No. QSK60-DM	Serial No. N/A	Manufacture Date: N/A
Rebuilds Date: N/A	No. of Cylinders: 16	Compression Ratio: 14.5:1	EPN: NFLSOFP1

Application: ☐ Gas Compression ☐ Electric Generation ☐ Refrigeration ☒ Emergency/Stand by

☒ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☐ Fuel Injected

☒ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☒ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☐ Rich Burn

Ignition/Injection Timing: Fixed: Variable:

Manufacture Horsepower Rating: 2547 | Proposed Horsepower Rating: 2547

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (^{o}F)	Exit Velocity (FPS)
89.9	1.6	784	113

II. Fuel Data

Type of Fuel: ☐ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☒ Diesel

Fuel Consumption (BTU/bhp-hr): 6908 | Heat Value: 19536 Btu (HHV) | 18378 Btu/lb (LHV)

Sulfur Content (grains/100 scf - weight %): 0.0015 weight %

III. Emission Factors (Before Control)

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.77		2.61		0.0048		0.97		0.00025		0.15	

Source of Emission Factors: ☐ Manufacturer Data ☒ AP-42 ☒ Other (specify): NSPS IIII, AP-42 (CH2O)

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.77		2.61		0.0048		0.97		0.00025		0.15	

Method of Emission Control: ☐ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):______________________________

***Note:** Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☒ Yes ☐ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☒ MACT ZZZZ ☒ NSPS IIII ☐ Title 30 Chapter 117 - List County: ____________________

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data			
Manufacturer: Cummins	Model No. QSK60-DM	Serial No. N/A	Manufacture Date: N/A
Rebuilds Date: N/A	No. of Cylinders: 16	Compression Ratio: 14.5:1	EPN: NFLSOFP2

Application: ☐ Gas Compression ☐ Electric Generation ☐ Refrigeration ☒ Emergency/Stand by

☒ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☐ Fuel Injected

☒ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☒ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☐ Rich Burn

Ignition/Injection Timing: Fixed: Variable:

Manufacture Horsepower Rating: 2547 | Proposed Horsepower Rating: 2547

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (^{o}F)	Exit Velocity (FPS)
89.9	1.6	784	113

II. Fuel Data

Type of Fuel: ☐ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☒ Diesel

Fuel Consumption (BTU/bhp-hr): 6908 | Heat Value: 19536 Btu/lb (HHV) | 18378 Btu/lb (LHV)

Sulfur Content (grains/100 scf - weight %): 0.0015 weight %

III. Emission Factors (Before Control)

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.77		2.61		0.0048		0.97		0.00025		0.15	

Source of Emission Factors: ☐ Manufacturer Data ☒ AP-42 ☒ Other (specify): NSPS IIII, AP-42 (CH2O)

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.77		2.61		0.0048		0.97		0.00025		0.15	

Method of Emission Control: ☐ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):______________________________

Note: *Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☒ Yes ☐ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☒ MACT ZZZZ ☒ NSPS IIII ☐ Title 30 Chapter 117 - List County: ____________________

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data

Manufacturer:	Model No.	Serial No.	Manufacture Date:
Caterpillar	C175-16	N/A	N/A
Rebuilds Date:	**No. of Cylinders:**	**Compression Ratio:**	**EPN:**
N/A	16	15.3:1	OSEGN1

Application: ☐ Gas Compression ☐ Electric Generation ☐ Refrigeration ☒ Emergency/Stand by

☒ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☐ Fuel Injected

☒ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☒ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☐ Rich Burn

Ignition/Injection Timing: Fixed: Variable:

Manufacture Horsepower Rating: 4021 Proposed Horsepower Rating: 4021

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (^oF)	Exit Velocity (FPS)
78.7	2.3	892	103

II. Fuel Data

Type of Fuel: ☐ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☒ Diesel

Fuel Consumption (BTU/bhp-hr): 7727 | Heat Value: 19536 Btu (HHV) | 18378 Btu/lb (LHV)

Sulfur Content (grains/100 scf - weight %): 0.0015 weight %

III. Emission Factors (Before Control)

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.77		2.61		0.0054		0.97		0.00028		0.15	

Source of Emission Factors: ☐ Manufacturer Data ☒ AP-42 ☒ Other (specify): NSPS IIII, AP-42 (CH2O)

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.77		2.61		0.0054		0.97		0.00028		0.15	

Method of Emission Control: ☐ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):______________________________

Note: *Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☒ Yes ☐ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☒ MACT ZZZZ ☒ NSPS IIII ☐ Title 30 Chapter 117 - List County: ____________________

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data			
Manufacturer: Caterpillar	Model No. C175-16	Serial No. N/A	Manufacture Date: N/A
Rebuilds Date: N/A	No. of Cylinders: 16	Compression Ratio: 15.3:1	EPN: OSEGN2

Application: ☐ Gas Compression ☐ Electric Generation ☐ Refrigeration ☒ Emergency/Stand by

☒ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☐ Fuel Injected

☒ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☒ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☐ Rich Burn

Ignition/Injection Timing: Fixed: Variable:

Manufacture Horsepower Rating: 4021 | Proposed Horsepower Rating: 4021

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (^oF)	Exit Velocity (FPS)
78.7	2.3	892	103

II. Fuel Data

Type of Fuel: ☐ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☒ Diesel

Fuel Consumption (BTU/bhp-hr): 7727 | Heat Value: 19536 Btu (HHV) | 18378 Btu/lb (LHV)

Sulfur Content (grains/100 scf - weight %): 0.0015 weight %

III. Emission Factors (Before Control)

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.77		2.61		0.0054		0.97		0.00028		0.15	

Source of Emission Factors: ☐ Manufacturer Data ☒ AP-42 ☒ Other (specify): NSPS IIII, AP-42 (CH2O)

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.77		2.61		0.0054		0.97		0.00028		0.15	

Method of Emission Control: ☐ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):________________

Note: *Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☒ Yes ☐ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☒ MACT ZZZZ ☒ NSPS IIII ☐ Title 30 Chapter 117 - List County: ________________

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data

Manufacturer:	Model No.	Serial No.	Manufacture Date:
Cummins	CFP7E-F30	N/A	N/A
Rebuilds Date:	**No. of Cylinders:**	**Compression Ratio:**	**EPN:**
N/A	6	17.2:1	OSFP

Application: [ ] Gas Compression [ ] Electric Generation [ ] Refrigeration [X] Emergency/Stand by

[X] 4 Stroke Cycle [ ] 2 Stroke Cycle [ ] Carbureted [ ] Spark Ignited [ ] Dual Fuel [ ] Fuel Injected

[X] Diesel [ ] Naturally Aspirated [ ] Blower /Pump Scavenged [ ] Turbo Charged and I.C. [X] Turbo Charged

[ ] Intercooled [ ] I.C. Water Temperature [ ] Lean Burn [ ] Rich Burn

Ignition/Injection Timing: Fixed: Variable:

Manufacture Horsepower Rating: 190 | Proposed Horsepower Rating: 190

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (^oF)	Exit Velocity (FPS)
19.7	0.5	828	103

II. Fuel Data

Type of Fuel: [ ] Field Gas [ ] Landfill Gas [ ] LP Gas [ ] Natural Gas [ ] Digester Gas [X] Diesel

Fuel Consumption (BTU/bhp-hr): 7471 | Heat Value: 19536 Btu (HHV) | 18378 Btu/lb (LHV)

Sulfur Content (grains/100 scf - weight %): 0.0015 weight %

III. Emission Factors (Before Control)

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
2.98		2.61		0.0052		0.97		0.004		0.15	

Source of Emission Factors: [ ] Manufacturer Data [X] AP-42 [X] Other (specify): NSPS IIII, AP-42 (CH2O)

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
2.98		2.61		0.0052		0.97		0.004		0.15	

Method of Emission Control: [ ] NSCR Catalyst [ ] Lean Operation [ ] Parameter Adjustment

[ ] Stratified Charge [ ] JLCC Catalyst [ ] Other (Specify):____________________

Note: *Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? [X] Yes [ ] No

V. Federal and State Standards (Check all that apply)

[ ] NSPS JJJJ [ ] MACT ZZZZ [X] NSPS IIII [ ] Title 30 Chapter 117 - List County: ____________________

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

TCEQ

I. Engine Data			
Manufacturer: Cummins	Model No. KTA50-DM1	Serial No. N/A	Manufacture Date: N/A
Rebuilds Date: N/A	No. of Cylinders: 16	Compression Ratio: 13.9:1	EPN: SFLSOEGN

Application: ☐ Gas Compression ☐ Electric Generation ☐ Refrigeration ☒ Emergency/Stand by

☒ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☐ Fuel Injected

☒ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☒ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☐ Rich Burn

Ignition/Injection Timing: Fixed: Variable:

Manufacture Horsepower Rating: 1729 Proposed Horsepower Rating: 1729

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (°F)	Exit Velocity (FPS)
65.1	1.6	835	73

II. Fuel Data

Type of Fuel: ☐ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☒ Diesel

Fuel Consumption (BTU/bhp-hr): 6651 | Heat Value: 19536 Btu/lb (HHV) | 18378 Btu/lb (LHV)

Sulfur Content (grains/100 scf - weight %): 0.0015 weight %

III. Emission Factors (Before Control)

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.77		2.61		0.0046		0.97		0.00024		0.15	

Source of Emission Factors: ☐ Manufacturer Data ☒ AP-42 ☒ Other (specify): NSPS IIII, AP-42 (CH2O)

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.77		2.61		0.0046		0.97		0.00024		0.15	

Method of Emission Control: ☐ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):____________________

Note: *Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☒ Yes ☐ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☒ MACT ZZZZ ☒ NSPS IIII ☐ Title 30 Chapter 117 - List County: ________________

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

TCEQ

I. Engine Data			
Manufacturer: MAN	Model No. 12V32/40	Serial No. N/A	Manufacture Date: N/A
Rebuilds Date: N/A	No. of Cylinders: 12	Compression Ratio: N/A	EPN: SESGEN1

Application: ☐ Gas Compression ☒ Electric Generation ☐ Refrigeration ☐ Emergency/Stand by

☒ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☐ Fuel Injected

☒ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☒ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☐ Rich Burn

Ignition/Injection Timing: Fixed: Variable:

Manufacture Horsepower Rating: 7720 | Proposed Horsepower Rating: 7720

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (^{o}F)	Exit Velocity (FPS)
180.9	3.9	590	56

II. Fuel Data

Type of Fuel: ☐ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☒ Diesel

Fuel Consumption (BTU/bhp-hr): 6105 | Heat Value: 19536 Btu/lb (HHV) | 18378 Btu/lb (LHV)

Sulfur Content (grains/100 scf - weight %): 0.0015 weight %

III. Emission Factors (Before Control)

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
1.80		2.98		0.0043		0.97		0.00022		0.11	

Source of Emission Factors: ☐ Manufacturer Data ☒ AP-42 ☒ Other (specify): NSPS Subpart IIII, AP-42 (CH2O)

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
1.80		2.98		0.0043		0.97		0.00022		0.11	

Method of Emission Control: ☐ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):______________________

Note: *Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☒ Yes ☐ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☒ MACT ZZZZ ☒ NSPS IIII ☐ Title 30 Chapter 117 - List County: ______________

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data

Manufacturer:	Model No.	Serial No.	Manufacture Date:
MAN	12V32/40	N/A	N/A
Rebuilds Date:	**No. of Cylinders:**	**Compression Ratio:**	**EPN:**
N/A	12	N/A	SESGEN2

Application: ☐ Gas Compression ☒ Electric Generation ☐ Refrigeration ☐ Emergency/Stand by

☒ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☐ Fuel Injected

☒ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☒ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☐ Rich Burn

Ignition/Injection Timing: Fixed: Variable:

Manufacture Horsepower Rating**:** 7720 | Proposed Horsepower Rating: 7720

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (°F)	Exit Velocity (FPS)
180.9	3.9	590	56

II. Fuel Data

Type of Fuel: ☐ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☒ Diesel

Fuel Consumption (BTU/bhp-hr): 6105 | Heat Value: 19536 Btu (HHV) | 18378 Btu/lb (LHV)

Sulfur Content (grains/100 scf - weight %): 0.0015 weight %

III. Emission Factors (Before Control)

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
1.80		2.98		0.0043		0.97		0.00022		0.11	

Source of Emission Factors: ☐ Manufacturer Data ☒ AP-42 ☒ Other (specify): NSPS Subpart IIII, AP-42 (CH2O)

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
1.80		2.98		0.0043		0.97		0.00022		0.11	

Method of Emission Control: ☐ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):______________________________

Note: *Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☒ Yes ☐ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☒ MACT ZZZZ ☒ NSPS IIII ☐ Title 30 Chapter 117 - List County: ____________________

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data

Manufacturer:	Model No.	Serial No.	Manufacture Date:
Cummins	QSK60-DM	N/A	N/A
Rebuilds Date:	**No. of Cylinders:**	**Compression Ratio:**	**EPN:**
N/A	16	14.5:1	SFLSOFP1

Application: ☐ Gas Compression ☐ Electric Generation ☐ Refrigeration ☒ Emergency/Stand by

☒ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☐ Fuel Injected

☒ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☒ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☐ Rich Burn

Ignition/Injection Timing: Fixed: | Variable:

Manufacture Horsepower Rating: 2547 | Proposed Horsepower Rating: 2547

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (^{o}F)	Exit Velocity (FPS)
89.9	1.6	784	113

II. Fuel Data

Type of Fuel: ☐ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☒ Diesel

Fuel Consumption (BTU/bhp-hr): 6908 | Heat Value: 19536 Btu/lb (HHV) | 18378 Btu/lb (LHV)

Sulfur Content (grains/100 scf - weight %): 0.0015 weight %

III. Emission Factors (Before Control)

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.77		2.61		0.0048		0.97		0.00025		0.15	

Source of Emission Factors: ☐ Manufacturer Data ☒ AP-42 ☒ Other (specify): NSPS IIII, AP-42 (CH2O)

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.77		2.61		0.0048		0.97		0.00025		0.15	

Method of Emission Control: ☐ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):______________________________

Note: *Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☒ Yes ☐ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☒ MACT ZZZZ ☒ NSPS IIII ☐ Title 30 Chapter 117 - List County: ____________________

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data			
Manufacturer: Cummins	Model No. QSK60-DM	Serial No. N/A	Manufacture Date: N/A
Rebuilds Date: N/A	No. of Cylinders: 16	Compression Ratio: 14.5:1	EPN: SFLSOFP2

Application: ☐ Gas Compression ☐ Electric Generation ☐ Refrigeration ☒ Emergency/Stand by

☒ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☐ Fuel Injected

☒ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☒ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☐ Rich Burn

Ignition/Injection Timing: Fixed: Variable:

Manufacture Horsepower Rating: 2547 | Proposed Horsepower Rating: 2547

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (^{o}F)	Exit Velocity (FPS)
89.9	1.6	784	113

II. Fuel Data

Type of Fuel: ☐ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☒ Diesel

Fuel Consumption (BTU/bhp-hr): 6908 | Heat Value: 19536 Btu (HHV) | 18378 Btu/lb (LHV)

Sulfur Content (grains/100 scf - weight %): 0.0015 weight %

III. Emission Factors (Before Control)

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.77		2.61		0.0048		0.97		0.00025		0.15	

Source of Emission Factors: ☐ Manufacturer Data ☒ AP-42 ☒ Other (specify): NSPS IIII, AP-42 (CH2O)

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.77		2.61		0.0048		0.97		0.00025		0.15	

Method of Emission Control: ☐ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):________________________________

Note: *Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☒ Yes ☐ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☒ MACT ZZZZ ☒ NSPS IIII ☐ Title 30 Chapter 117 - List County: ____________________

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

North FLSO Compressor Turbine 1

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) NFLSOCT1

APPLICATION

____ Electric Generation
___ Base Load ___ Peaking
X Gas Compression
____ Other (Specify) ______

CYCLE

X Simple Cycle
____ Regenerative Cycle
____ Cogeneration
____ Combined Cycle

Manufacturer Rolls Royce
Model No. Trent 60 WLE
Serial No. N/A

Model represented is based on:
X Preliminary Design ____ Contract Award
____ Other(specify) ______
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 59.0 MW (79,122 hp) (MW)(hp)
Proposed Site Operating Range 59.0 MW (79,122 hp) (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 8,342 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ____ Process Offgas ____ Landfill/Digester Gas
____ Fuel Oil ____ Refinery Gas ____ Other

Backup Fuels:
X Not Provided ____ Process Offgas ____ Ethane
____ Fuel Oil ____ Refinery Gas ____ Other (specify) ______

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
____ Lean Premix Combustors ____ Oxidation Catalyst X Water Injection ____ Other(specify)
____ Other Low-NOx Combustor ____ SCR Catalyst ____ Steam Injection ____

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

North FLSO Compressor Turbine 2

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) NFLSOCT2

APPLICATION

_____ Electric Generation
___ Base Load ___ Peaking
X Gas Compression
_____ Other (Specify) _____

CYCLE

X Simple Cycle
____ Regenerative Cycle
____ Cogeneration
____ Combined Cycle

Manufacturer Rolls Royce
Model No. Trent 60 WLE
Serial No. N/A

Model represented is based on:
X Preliminary Design ____ Contract Award
____ Other(specify) ________
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 59.0 MW (79,122 hp) (MW)(hp)
Proposed Site Operating Range 59.0 MW (79,122 hp) (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 8,342 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ____ Process Offgas ____ Landfill/Digester Gas
____ Fuel Oil ____ Refinery Gas ____ Other

Backup Fuels:
X Not Provided ____ Process Offgas ____ Ethane
____ Fuel Oil ____ Refinery Gas ____ Other (specify) ____

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
____ Lean Premix Combustors ____ Oxidation Catalyst X Water Injection ____ Other(specify)
____ Other Low-NOx Combustor ____ SCR Catalyst ____ Steam Injection ____

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

North FLSO Compressor Turbine 3

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) NFLSOCT3

APPLICATION	CYCLE
____ Electric Generation ___ Base Load ___ Peaking X Gas Compression ____ Other (Specify) ______	X Simple Cycle ____ Regenerative Cycle ____ Cogeneration ____ Combined Cycle

Manufacturer Rolls Royce
Model No. Trent 60 WLE
Serial No. N/A

Model represented is based on:
X Preliminary Design ____ Contract Award
____ Other(specify) ______
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 59.0 MW (79,122 hp) (MW)(hp)
Proposed Site Operating Range 59.0 MW (79,122 hp) (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 8,342 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ____ Process Offgas ____ Landfill/Digester Gas
____ Fuel Oil ____ Refinery Gas ____ Other

Backup Fuels:
X Not Provided ____ Process Offgas ____ Ethane
____ Fuel Oil ____ Refinery Gas ____ Other (specify) ______

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
____ Lean Premix Combustors ____ Oxidation Catalyst X Water Injection ____ Other(specify)
____ Other Low-NOx Combustor ____ SCR Catalyst ____ Steam Injection ____

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

North FLSO Compressor Turbine 4

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) NFLSOCT4

APPLICATION

____ Electric Generation
___ Base Load ___ Peaking
X Gas Compression
____ Other (Specify) ________

CYCLE

X Simple Cycle
____ Regenerative Cycle
____ Cogeneration
____ Combined Cycle

Manufacturer Rolls Royce
Model No. Trent 60 WLE
Serial No. N/A

Model represented is based on:
X Preliminary Design ____ Contract Award
____ Other(specify) ________
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 59.0 MW (79,122 hp) (MW)(hp)
Proposed Site Operating Range 59.0 MW (79,122 hp) (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 8,342 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ____ Process Offgas ____ Landfill/Digester Gas
____ Fuel Oil ____ Refinery Gas ____ Other

Backup Fuels:
X Not Provided ____ Process Offgas ____ Ethane
____ Fuel Oil ____ Refinery Gas ____ Other (specify) ________

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
____ Lean Premix Combustors ____ Oxidation Catalyst X Water Injection ____ Other(specify)
____ Other Low-NOx Combustor ____ SCR Catalyst ____ Steam Injection ____

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

North FLSO Power Turbine 1

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) NFLSOPT1

APPLICATION

___ Electric Generation
___ Base Load ___ Peaking
X Gas Compression
___ Other (Specify) ___

CYCLE

___ Simple Cycle
___ Regenerative Cycle
X Cogeneration
___ Combined Cycle

Manufacturer General Electric
Model No. LM2500+G4
Serial No. N/A

Model represented is based on:
X Preliminary Design ___ Contract Award
___ Other(specify) ___
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 36.95 MW (49,555 hp) (MW)(hp)
Proposed Site Operating Range 36.95 MW (49,555 hp) (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 9,093 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ___ Process Offgas ___ Landfill/Digester Gas
___ Fuel Oil ___ Refinery Gas ___ Other

Backup Fuels:
X Not Provided ___ Process Offgas ___ Ethane
___ Fuel Oil ___ Refinery Gas ___ Other (specify) ___

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
___ Lean Premix Combustors ___ Oxidation Catalyst X Water Injection ___ Other(specify)
___ Other Low-NOx Combustor ___ SCR Catalyst ___ Steam Injection ___

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

North FLSO Power Turbine 2

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) NFLSOPT2

APPLICATION	CYCLE
____ Electric Generation ___ Base Load ___ Peaking X Gas Compression ____ Other (Specify) ______	____ Simple Cycle ____ Regenerative Cycle X Cogeneration ____ Combined Cycle

Manufacturer General Electric
Model No. LM2500+G4
Serial No. N/A

Model represented is based on:
X Preliminary Design ____ Contract Award
____ Other(specify) ______
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 36.95 MW (49,555 hp) (MW)(hp)
Proposed Site Operating Range 36.95 MW (49,555 hp) (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 9,093 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ____ Process Offgas ____ Landfill/Digester Gas
____ Fuel Oil ____ Refinery Gas ____ Other

Backup Fuels:
X Not Provided ____ Process Offgas ____ Ethane
____ Fuel Oil ____ Refinery Gas ____ Other (specify) ______

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
____ Lean Premix Combustors ____ Oxidation Catalyst X Water Injection ____ Other(specify)
____ Other Low-NOx Combustor ____ SCR Catalyst ____ Steam Injection ______

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

North FLSO Power Turbine 3

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) NFLSOPT3

APPLICATION	CYCLE
____ Electric Generation ___ Base Load ___ Peaking X Gas Compression ____ Other (Specify) ____	____ Simple Cycle ____ Regenerative Cycle X Cogeneration ____ Combined Cycle

Manufacturer General Electric
Model No. LM2500+G4
Serial No. N/A

Model represented is based on:
X Preliminary Design ____ Contract Award
____ Other(specify) ____
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 36.95 MW (49,555 hp) (MW)(hp)
Proposed Site Operating Range 36.95 MW (49,555 hp) (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 9,093 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ____ Process Offgas ____ Landfill/Digester Gas
____ Fuel Oil ____ Refinery Gas ____ Other

Backup Fuels:
X Not Provided ____ Process Offgas ____ Ethane
____ Fuel Oil ____ Refinery Gas ____ Other (specify) ____

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
____ Lean Premix Combustors ____ Oxidation Catalyst X Water Injection ____ Other(specify)
____ Other Low-NOx Combustor ____ SCR Catalyst ____ Steam Injection ____

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

Onshore Power Turbine 1

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) OSPT1

APPLICATION

X Electric Generation
X Base Load ___ Peaking
___ Gas Compression
___ Other (Specify) ___

CYCLE

___ Simple Cycle
___ Regenerative Cycle
___ Cogeneration
X Combined Cycle

Manufacturer Siemens
Model No. SGT-400
Serial No. N/A

Model represented is based on:
X Preliminary Design ___ Contract Award
___ Other(specify) ___
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 13.5 MW (18,078 hp) (MW)(hp) [for GT only]
Proposed Site Operating Range 13.5 MW (18,078 hp) (MW)(hp) [for GT only]
Manufacturer's Rated Heat Rate at Baseload, ISO 9,731 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ___ Process Offgas ___ Landfill/Digester Gas
___ Fuel Oil ___ Refinery Gas ___ Other

Backup Fuels:
X Not Provided ___ Process Offgas ___ Ethane
___ Fuel Oil ___ Refinery Gas ___ Other (specify) ___

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
x Lean Premix Combustors ___ Oxidation Catalyst ___ Water Injection ___ Other(specify)
___ Other Low-NOx Combustor ___ SCR Catalyst ___ Steam Injection ___

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

Onshore Power Turbine 2

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) OSPT2

APPLICATION

X Electric Generation
X Base Load ___ Peaking
___ Gas Compression
___ Other (Specify) ___

CYCLE

___ Simple Cycle
___ Regenerative Cycle
___ Cogeneration
X Combined Cycle

Manufacturer Siemens
Model No. SGT-400
Serial No. N/A

Model represented is based on:
X Preliminary Design ___ Contract Award
___ Other(specify) ___
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 13.5 MW (18,078 hp) (MW)(hp) [for GT only]
Proposed Site Operating Range 13.5 MW (18,078 hp) (MW)(hp) [for GT only]
Manufacturer's Rated Heat Rate at Baseload, ISO 9,731 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ___ Process Offgas ___ Landfill/Digester Gas
___ Fuel Oil ___ Refinery Gas ___ Other

Backup Fuels:
X Not Provided ___ Process Offgas ___ Ethane
___ Fuel Oil ___ Refinery Gas ___ Other (specify) ___

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
x Lean Premix Combustors ___ Oxidation Catalyst ___ Water Injection ___ Other(specify)
___ Other Low-NOx Combustor ___ SCR Catalyst ___ Steam Injection ___

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

Onshore Power Turbine 3

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) OSPT3

APPLICATION

X Electric Generation
X Base Load ___ Peaking
___ Gas Compression
___ Other (Specify) ___

CYCLE

___ Simple Cycle
___ Regenerative Cycle
___ Cogeneration
X Combined Cycle

Manufacturer Siemens
Model No. SGT-400
Serial No. N/A

Model represented is based on:
X Preliminary Design ___ Contract Award
___ Other(specify) ___
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 13.5 MW (18,078 hp) (MW)(hp) [for GT only]
Proposed Site Operating Range 13.5 MW (18,078 hp) (MW)(hp) [for GT only]
Manufacturer's Rated Heat Rate at Baseload, ISO 9,731 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ___ Process Offgas ___ Landfill/Digester Gas
___ Fuel Oil ___ Refinery Gas ___ Other

Backup Fuels:
X Not Provided ___ Process Offgas ___ Ethane
___ Fuel Oil ___ Refinery Gas ___ Other (specify) ___

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
x Lean Premix Combustors ___ Oxidation Catalyst ___ Water Injection ___ Other(specify)
___ Other Low-NOx Combustor ___ SCR Catalyst ___ Steam Injection ___

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

Onshore Power Turbine 4

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) OSPT4

APPLICATION

X Electric Generation
X Base Load ___ Peaking
___ Gas Compression
___ Other (Specify) ___

CYCLE

___ Simple Cycle
___ Regenerative Cycle
___ Cogeneration
X Combined Cycle

Manufacturer Siemens
Model No. SGT-400
Serial No. N/A

Model represented is based on:
X Preliminary Design ___ Contract Award
___ Other(specify) ___
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 13.5 MW (18,078 hp) (MW)(hp) [for GT only]
Proposed Site Operating Range 13.5 MW (18,078 hp) (MW)(hp) [for GT only]
Manufacturer's Rated Heat Rate at Baseload, ISO 9,731 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ___ Process Offgas ___ Landfill/Digester Gas
___ Fuel Oil ___ Refinery Gas ___ Other

Backup Fuels:
X Not Provided ___ Process Offgas ___ Ethane
___ Fuel Oil ___ Refinery Gas ___ Other (specify) ___

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
x Lean Premix Combustors ___ Oxidation Catalyst ___ Water Injection ___ Other(specify)
___ Other Low-NOx Combustor ___ SCR Catalyst ___ Steam Injection ___

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

Onshore Power Turbine 5

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) OSPT5

APPLICATION

X Electric Generation
X Base Load ___ Peaking
___ Gas Compression
___ Other (Specify) ___________

CYCLE

___ Simple Cycle
___ Regenerative Cycle
___ Cogeneration
X Combined Cycle

Manufacturer Siemens
Model No. SGT-400
Serial No. N/A

Model represented is based on:
X Preliminary Design ___ Contract Award
___ Other(specify) ___________
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 13.5 MW (18,078 hp) (MW)(hp) [for GT only]
Proposed Site Operating Range 13.5 MW (18,078 hp) (MW)(hp) [for GT only]
Manufacturer's Rated Heat Rate at Baseload, ISO 9,731 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ___ Process Offgas ___ Landfill/Digester Gas
___ Fuel Oil ___ Refinery Gas ___ Other

Backup Fuels:
X Not Provided ___ Process Offgas ___ Ethane
___ Fuel Oil ___ Refinery Gas ___ Other (specify) ___________

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
x Lean Premix Combustors ___ Oxidation Catalyst ___ Water Injection ___ Other(specify)
___ Other Low-NOx Combustor ___ SCR Catalyst ___ Steam Injection ___

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

Onshore Power Turbine 6

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) OSPT6

APPLICATION

X Electric Generation
X Base Load ___ Peaking
___ Gas Compression
___ Other (Specify) ______

CYCLE

___ Simple Cycle
___ Regenerative Cycle
___ Cogeneration
X Combined Cycle

Manufacturer Siemens
Model No. SGT-400
Serial No. N/A

Model represented is based on:
X Preliminary Design ___ Contract Award
___ Other(specify) ______
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 13.5 MW (18,078 hp) (MW)(hp) [for GT only]
Proposed Site Operating Range 13.5 MW (18,078 hp) (MW)(hp) [for GT only]
Manufacturer's Rated Heat Rate at Baseload, ISO 9,731 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ___ Process Offgas ___ Landfill/Digester Gas
___ Fuel Oil ___ Refinery Gas ___ Other

Backup Fuels:
X Not Provided ___ Process Offgas ___ Ethane
___ Fuel Oil ___ Refinery Gas ___ Other (specify) ______

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
x Lean Premix Combustors ___ Oxidation Catalyst ___ Water Injection ___ Other(specify)
___ Other Low-NOx Combustor ___ SCR Catalyst ___ Steam Injection ______

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

Onshore Power Turbine 7

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) OSPT7

APPLICATION

X Electric Generation
X Base Load ___ Peaking
___ Gas Compression
___ Other (Specify) ________

CYCLE

___ Simple Cycle
___ Regenerative Cycle
___ Cogeneration
X Combined Cycle

Manufacturer Siemens
Model No. SGT-400
Serial No. N/A

Model represented is based on:
X Preliminary Design ___ Contract Award
___ Other(specify) ________
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 13.5 MW (18,078 hp) (MW)(hp) [for GT only]
Proposed Site Operating Range 13.5 MW (18,078 hp) (MW)(hp) [for GT only]
Manufacturer's Rated Heat Rate at Baseload, ISO 9,731 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ___ Process Offgas ___ Landfill/Digester Gas
___ Fuel Oil ___ Refinery Gas ___ Other

Backup Fuels:
X Not Provided ___ Process Offgas ___ Ethane
___ Fuel Oil ___ Refinery Gas ___ Other (specify) ________

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
x Lean Premix Combustors ___ Oxidation Catalyst ___ Water Injection ___ Other(specify)
___ Other Low-NOx Combustor ___ SCR Catalyst ___ Steam Injection ________

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

South FLSO Compressor Turbine 1

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) SFLSOCT1

APPLICATION

________ Electric Generation
___ Base Load ___ Peaking
X Gas Compression
________ Other (Specify) ________

CYCLE

X Simple Cycle
____ Regenerative Cycle
____ Cogeneration
____ Combined Cycle

Manufacturer Rolls Royce
Model No. Trent 60 WLE
Serial No. N/A

Model represented is based on:
X Preliminary Design ____ Contract Award
____ Other(specify) ________
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 59.0 MW (79,122 hp) (MW)(hp)
Proposed Site Operating Range 59.0 MW (79,122 hp) (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 8,342 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ____ Process Offgas ____ Landfill/Digester Gas
____ Fuel Oil ____ Refinery Gas ____ Other

Backup Fuels:
X Not Provided ____ Process Offgas ____ Ethane
____ Fuel Oil ____ Refinery Gas ____ Other (specify) ____

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
____ Lean Premix Combustors ____ Oxidation Catalyst X Water Injection ____ Other(specify)
____ Other Low-NOx Combustor ____ SCR Catalyst ____ Steam Injection ____

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

South FLSO Compressor Turbine 2

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) SFLSOCT2

APPLICATION

______ Electric Generation
___ Base Load ___ Peaking
X Gas Compression
______ Other (Specify) ______

CYCLE

X Simple Cycle
____ Regenerative Cycle
____ Cogeneration
____ Combined Cycle

Manufacturer Rolls Royce
Model No. Trent 60 WLE
Serial No. N/A

Model represented is based on:
X Preliminary Design ____ Contract Award
____ Other(specify) ______
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 59.0 MW (79,122 hp) (MW)(hp)
Proposed Site Operating Range 59.0 MW (79,122 hp) (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 8,342 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ______ Process Offgas ______ Landfill/Digester Gas
____ Fuel Oil ______ Refinery Gas ______ Other

Backup Fuels:
X Not Provided ______ Process Offgas ______ Ethane
____ Fuel Oil ______ Refinery Gas ______ Other (specify) ______

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
______ Lean Premix Combustors ______ Oxidation Catalyst X Water Injection ______ Other(specify)
______ Other Low-NOx Combustor ______ SCR Catalyst ______ Steam Injection ______

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

South FLSO Compressor Turbine 3

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) SFLSOCT3

APPLICATION	CYCLE
______ Electric Generation ___ Base Load ___ Peaking X Gas Compression ______ Other (Specify) ______	X Simple Cycle ____ Regenerative Cycle ____ Cogeneration ____ Combined Cycle

Manufacturer Rolls Royce
Model No. Trent 60 WLE
Serial No. N/A

Model represented is based on:
X Preliminary Design ____ Contract Award
____ Other(specify) ____________
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 59.0 MW (79,122 hp) (MW)(hp)
Proposed Site Operating Range 59.0 MW (79,122 hp) (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 8,342 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ______ Process Offgas ______ Landfill/Digester Gas
____ Fuel Oil ______ Refinery Gas ______ Other

Backup Fuels:
X Not Provided ______ Process Offgas ______ Ethane
____ Fuel Oil ______ Refinery Gas ______ Other (specify) ______

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
______ Lean Premix Combustors ______ Oxidation Catalyst X Water Injection ______ Other(specify)
______ Other Low-NOx Combustor ______ SCR Catalyst ______ Steam Injection ______

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

South FLSO Compressor Turbine 4

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) SFLSOCT4

APPLICATION

_____ Electric Generation
___ Base Load ___ Peaking
X Gas Compression
_____ Other (Specify) _____

CYCLE

X Simple Cycle
____ Regenerative Cycle
____ Cogeneration
____ Combined Cycle

Manufacturer Rolls Royce
Model No. Trent 60 WLE
Serial No. N/A

Model represented is based on:
X Preliminary Design ____ Contract Award
____ Other(specify) ____________
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 59.0 MW (79,122 hp) (MW)(hp)
Proposed Site Operating Range 59.0 MW (79,122 hp) (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 8,342 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ______ Process Offgas ______ Landfill/Digester Gas
____ Fuel Oil ______ Refinery Gas ______ Other

Backup Fuels:
X Not Provided ______ Process Offgas ______ Ethane
____ Fuel Oil ______ Refinery Gas ______ Other (specify) ______

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
______ Lean Premix Combustors ______ Oxidation Catalyst X Water Injection ______ Other(specify)
______ Other Low-NOx Combustor ______ SCR Catalyst ______ Steam Injection ______

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

South FLSO Power Turbine 1

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) SFLSOPT1

APPLICATION

_____ Electric Generation
___ Base Load ___ Peaking
X Gas Compression
_____ Other (Specify) _____

CYCLE

_____ Simple Cycle
_____ Regenerative Cycle
X Cogeneration
_____ Combined Cycle

Manufacturer General Electric
Model No. LM2500+G4
Serial No. N/A

Model represented is based on:
X Preliminary Design ____ Contract Award
____ Other(specify) _____
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 36.95 MW (49,555 hp) (MW)(hp)
Proposed Site Operating Range 36.95 MW (49,555 hp) (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 9,093 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ____ Process Offgas ____ Landfill/Digester Gas
____ Fuel Oil ____ Refinery Gas ____ Other

Backup Fuels:
X Not Provided ____ Process Offgas ____ Ethane
____ Fuel Oil ____ Refinery Gas ____ Other (specify) ____

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
____ Lean Premix Combustors ____ Oxidation Catalyst X Water Injection ____ Other(specify)
____ Other Low-NOx Combustor ____ SCR Catalyst ____ Steam Injection ____

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

South FLSO Power Turbine 2

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) SFLSOPT2

APPLICATION

_____ Electric Generation
___ Base Load ___ Peaking
__X__ Gas Compression
_____ Other (Specify) _______

CYCLE

_____ Simple Cycle
_____ Regenerative Cycle
X____ Cogeneration
_____ Combined Cycle

Manufacturer General Electric
Model No. LM2500+G4
Serial No. N/A

Model represented is based on:
X___ Preliminary Design ____ Contract Award
____ Other(specify) ________
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 36.95 MW (49,555 hp) (MW)(hp)
Proposed Site Operating Range 36.95 MW (49,555 hp) (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 9,093 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X___ Natural Gas _______ Process Offgas _______ Landfill/Digester Gas
____ Fuel Oil _______ Refinery Gas _______ Other

Backup Fuels:
X___ Not Provided _______ Process Offgas _______ Ethane
____ Fuel Oil _______ Refinery Gas _______ Other (specify) _______

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
_______ Lean Premix Combustors _______ Oxidation Catalyst X_______ Water Injection _____ Other(specify)
_______ Other Low-NOx Combustor _______ SCR Catalyst _______ Steam Injection _______

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

South FLSO Power Turbine 3

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) SFLSOPT3

APPLICATION	CYCLE
____ Electric Generation ___ Base Load ___ Peaking X Gas Compression ____ Other (Specify) ________	____ Simple Cycle ____ Regenerative Cycle X Cogeneration ____ Combined Cycle

Manufacturer General Electric
Model No. LM2500+G4
Serial No. N/A

Model represented is based on:
X Preliminary Design ____ Contract Award
____ Other(specify) ____________
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 36.95 MW (49,555 hp) (MW)(hp)
Proposed Site Operating Range 36.95 MW (49,555 hp) (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 9,093 (LHV, at turbine shaft) (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ____ Process Offgas ____ Landfill/Digester Gas
____ Fuel Oil ____ Refinery Gas ____ Other

Backup Fuels:
X Not Provided ____ Process Offgas ____ Ethane
____ Fuel Oil ____ Refinery Gas ____ Other (specify) ____

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
____ Lean Premix Combustors ____ Oxidation Catalyst X Water Injection ____ Other(specify)
____ Other Low-NOx Combustor ____ SCR Catalyst ____ Steam Injection ____

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

APPENDIX B
Emission Calculations

Lavaca Bay LNG Project
Facility-Wide Potential GHG Emissions

FLSO Facilities (totals for 2 FLSOs combined)	Annual Emissions, tpy CO_2	CH_4	N_2O	CO_2e
Refrigerator Compressor Turbines (x8)	2,191,437	206.6	4.1	2,197,833
Compressor Turbine Startup/Shutdown	0	0.79	0	20
Power Generation Turbines (x6)	733,445	43.1	1.4	734,935
Essential Generators (x4)	11,067	0.45	0.090	11,105
Emergency Diesel Generator (x2)	98	4.0E-03	7.9E-04	98
Diesel Fire Water Pumps (x4)	298	0.012	2.4E-03	299
Cold Flare (x2)	11,196	39.3	0.021	12,185
Warm Flare (x2)	11,161	39.1	0.021	12,145
LNG Tank Inspection (all tanks)	1,288	16.0	2.3E-03	1,688
LNGC Gas-In and Cooldown (all LNGCs)	20,453	111.0	0.038	23,238
Fuel Tanks (all FLSO tanks)	0	0	0	0
FLSO Fugitive Emissions	0	5.8	0	145

Onshore Facilities (totals for both phases)	Annual Emissions, tpy CO_2	CH_4	N_2O	CO_2e
Power Generation Turbines (x7)	437,864	8.3	0.83	438,316
Steam Boilers (x2)	221,029	4.2	0.42	221,257
Thermal Oxidizers (x2)	513,870	2.6	0.17	513,987
Regeneration Gas Heaters (x2)	48,776	0.92	0.092	48,826
Emergency Diesel Generators (x2)	507	0.021	4.1E-03	508
Diesel Fire Water Pump	6	2.4E-04	4.9E-05	6
Onshore Ground Flare (x1)	215	0.75	4.0E-04	234
Cooling Towers (x2)	0	0	0	0
Condensate Tanks and Loadout (x2)	0	0	0	0
Fuel Tanks (all onshore tanks)	0	0	0	0
Onshore Fugitive Emissions	0.16	4.3	0	107

FLSO Facilities Annual Totals	2,980,444	462.1	5.7	2,993,691
Onshore Facilities Annual Totals	1,222,266	21.0	1.5	1,223,242
Facility-Wide Annual GHG Totals (PSD)	**4,202,710**	**483.1**	**7.2**	**4,216,932**

Lavaca Bay LNG Project
FLSO Compressor Turbines (x4 per FLSO)

Rolls Royce Trent 60 WLE Vendor Data		Annual tpy	Max. CO ppm	Max. CO lb/hr
Case number		95	101	67
Load condition	% Base	100	75.91	100
Altitude	m	40	40	40
Barometric pressure	kPa	100.846	100.846	100.846
Ambient temperature	°C	15	-10	-10
Ambient relative humidity	%	80	80	80
Air cooling type		None	None	None
Engine inlet air flow	kg/s	152.1	150.5	167.9
Engine output shaft speed	rpm	3,307	3,307	3361
Power at engine shaft	kW	59,001.0	44,790.0	59001
Heat rate at engine shaft	kJ/kWh (LHV basis)	8,801.6	8,942.3	8637.4
Efficiency at engine shaft	% (LHV basis)	41.72	41.06	42.51
GT fuel flow	kg/hr	11,472.0	8,848.0	10334
Fuel energy flow (LHV basis)	kW	141,296.1	108,982.0	138664.3
Combustion water injection flow	kg/hr	11,914.0	7,518.0	11170
Exhaust flow	kg/s	157.6	154	172.7
Exhaust temperature	°C	439.3	347.9	375.9
Exhaust N2	mol %	72.135	74.330	73.534
Exhaust O2	mol %	13.018	14.885	14.06
Exhaust CO2	mol %	3.165	2.533	2.878
Exhaust Water	mol %	10.819	7.362	8.647
Exhaust Argon	mol %	0.860	0.887	0.879
Exhaust Neon	mol %	0.003	0.003	0.003
UHC (methane equivalent)	ppmvd at 15% O2	10.8	21.1	16.9
VOC (methane equivalent)	ppmvd at 15% O2	2.2	4.2	3.4

Molecular Weights (g/g-mol)

N2	28
O2	32
CO2	44
H2O	18
Ar	39.95
Ne	20.18

Calculated Heat Input

GT heat input (per turbine)	MMBtu/hr (HHV)	534.7	412.4	524.7
Exhaust MW	g/g-mol	28.048	28.370	28.263
Exhaust flow	Nm^3/hr at 0 °C	453,115	437,732	492,748
Exhaust flow	m^3/hr, actual temp.	1,181,848	995,253	1,170,851
Stack height	m	67.17	67.17	67.17
Stack diameter	m	2.9	2.9	2.9
Exit velocity	m/s	49.7	41.9	49.2

	Case 95		Case 101		Case 67	
Calculated Emissions	15 °C Ambient		-10 °C Ambient		-10 °C Ambient	
Pollutant	lb/MMBtu (HHV)	lb/hr (per turbine)	lb/MMBtu (HHV)	lb/hr (per turbine)	lb/MMBtu (HHV)	lb/hr (per turbine)
CO2	117.0	62,541	117.0	48,238	117.0	61,376
CH4	0.0110	5.9	0.0217	8.9	0.0173	9.1
N2O	0.00022	0.12	0.00022	0.091	0.00022	0.12
CO2e	N/A	62,724	N/A	48,489	N/A	61,638

Hourly and Annual Totals	Worst-case lb/hr		Annual emissions, tons	
Pollutant	x1 turbine	x8 turbines	x1 turbine	x8 turbines
CO2	62,541	500,328	273,930	2,191,437
CH4	9.1	72.7	25.8	206.6
N2O	0.12	0.94	0.52	4.1
CO2e	62,724	501,788	274,729	2,197,833

Notes:
1) Annual emissions are based on case number 95 from vendor performance data sheet.
2) For annual emissions, it is assumed that each compressor turbine operates for the equivalent of 8,760 hours per year at full load.
3) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (53.06 kg/MMBtu), and N2O (0.0001 kg/MMBtu).
4) CH4 emissions are based on the vendor concentration for unburned hydrocarbons (UHC) minus the vendor VOC concentration.
5) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Lavaca Bay LNG Project

FLSO Compressor Turbine Startup/Shutdown Emissions (x4 per FLSO)

Rolls Royce Trent 60 WLE Vendor Data		Annual tpy	Max. CO and VOC ppm	Worst-case exhaust vel.
Case number		95	67	106
Load condition	% Base	100	100	75.91
Altitude	m	40	40	40
Barometric pressure	kPa	100.846	100.846	100.846
Ambient temperature	°C	15	-10	15
Ambient relative humidity	%	80	80	80
Air cooling type		None	None	None
Engine inlet air flow	kg/s	152.1	167.9	140.0
Engine output shaft speed	rpm	3,307	3361	3,307
Power at engine shaft	kW	59,001.0	59001	44,790.0
Heat rate at engine shaft	kJ/kWh (LHV basis)	8,801.6	8637.4	9,120.8
Efficiency at engine shaft	% (LHV basis)	41.72	42.51	40.26
GT fuel flow	kg/hr	11,472.0	10334	9,024.0
Fuel energy flow (LHV basis)	kW	141,296.1	138664.3	111,152.8
Combustion water injection flow	kg/hr	11,914.0	11170	8,386.0
Exhaust flow	kg/s	157.6	172.7	143.8
Exhaust temperature	°C	439.3	375.9	399.7
Exhaust N2	mol %	72.135	73.534	73.020
Exhaust O2	mol %	13.018	14.06	14.106
Exhaust CO2	mol %	3.165	2.878	2.744
Exhaust Water	mol %	10.819	8.647	9.256
Exhaust Argon	mol %	0.860	0.879	0.871
Exhaust Neon	mol %	0.003	0.003	0.003
UHC (methane equivalent)	ppmvd at 15% O2	10.8	16.9	13.5
VOC (methane equivalent)	ppmvd at 15% O2	2.2	3.4	2.7

Startup/Shutdown Mass Totals		Startup	Shutdown
Barometric pressure	kPa	101.325	101.325
Ambient temperature	°C	27.8	27.8
Ambient rel. humidity	%	60	60
Duration	minutes	10	11
UHC	lb/event	85	165
VOC	lb/event	17	33

Molecular Weights (g/g-mol)

N2	28
O2	32
CO2	44
H2O	18
Ar	39.95
Ne	20.18

Calculated Heat Input

GT heat input (per turbine)	MMBtu/hr (HHV)	534.7	524.7	420.6
Exhaust MW	g/g-mol	28.048	28.263	28.182
Exhaust flow	Nm^3/hr at 0 °C	453,115	492,748	411,476
Exhaust flow	m^3/hr, actual temp.	1,181,848	1,170,851	1,013,589
Stack height	m	67.17	67.17	67.17
Stack diameter	m	2.9	2.9	2.9
Exit velocity	m/s	49.7	49.2	42.6

Steady load hourly emission rates	Case 95		Case 67	
	15 °C Ambient		-10 °C Ambient	
Pollutant	lb/MMBtu (HHV)	lb/hr (per turbine)	lb/MMBtu (HHV)	lb/hr (per turbine)
CO2	116.9	62,494	117.0	61,376
CH4	0.0110	5.9	0.0173	9.1
N2O	0.00022	0.12	0.00022	0.12
CO2e	N/A	62,676	N/A	61,638

Incremental Startup/ Shutdown Emissions

Worst-case 60-minute total		Facility-wide additional emissions	
Startup (lbs per turbine)	Shutdown (lbs per turbine)	lbs/yr (one SUSD per turbine per yr)	tons/yr (one SUSD per turbine per yr)
62,494	62,494	N/A	N/A
75.6	139.6	1,575.8	0.79
0.12	0.12	N/A	N/A
64,418	66,018	40,669	20

Notes:
1) Worst case steady load hourly emissions are based on case number 95 on vendor data sheet.
2) Startup and shutdown emission data were provided by William Brown of Black & Veatch in anApril 14, 2014 email, based on typical Trent 60 data from John McIlvoy at Rolls Royce.
3) Maximum hourly emissions for startup/shutdown are calculated by taking total SU/SD pounds, and adding the 100% load rate at 15 °C for the remaining portion of the hour.
4) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (53.06 kg/MMBtu), and N2O (0.0001 kg/MMBtu).
5) CH4 emissions are based on the vendor concentration for unburned hydrocarbons (UHC) minus the vendor VOC concentration.
6) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Lavaca Bay LNG Project
FLSO Power Generation Turbines (x3 per FLSO)

GE LM2500+G4 Vendor Data		Annual tpy	Max. fuel	Max. CO ppm
Ambient temperature	°C	24	4.4	-5
Altitude	m	27	27	27
Barometric pressure	mBar	1,010	1,010	1,010
Relative humidity	%	60	60	60
Fuel LHV	kJ/kg	47,765	47,765	47,765
Turbine shaft speed	rpm	3,600	3,600	3,600
Turbine power output	kW	32,888	36,954	36,632
Generator power output	kWe	31,984	35,938	35,625
Heat rate	kJ/kWh	9,774	9,594	9,530
Heat rate at generator terminal	kJ/kWeh	10,203	10,016	9,949
Thermal efficiency	%	36.84	37.53	37.78
Air flow rate at inlet	kg/s	86.84	94.37	96.16
Exhaust flow	kg/s	90.19	98.29	99.88
Total steam/water flow	kg/hr	8,487	10,083	9,538
Fuel nozzle injection?		Water	Water	Water
Fuel nozzle steam/water	kg/hr	8,487	10,083	9,538
Oxygen reference level	%	15	15	15
Unburned hydrocarbons	ppmvd at 15% O2	7	22	24
CO2	kg/s	4.93	5.42	5.34
Exhaust molecular weight	kg/kmol	27.897	27.977	28.047
Nitrogen	% vol	70.983	71.566	72.05
Oxygen	% vol	12.144	12.202	12.533
Water vapor	% vol	12.557	11.856	11.136
Carbon dioxide	% vol	3.462	3.508	3.408
Argon	% vol	0.848	0.855	0.861

Calculated Heat Input and Exhaust Stack Parameters

Ambient temperature	°C	24	4.4	-5
GT heat input (per turbine)	MMBtu/hr (HHV)	337.9	372.7	367.0
WHRU inlet temp.	°C	542.5	542.5	542.5
WHRU outlet temp.	°C	395	395	395
Exhaust flow	Nm^3/hr at 0 °C	260,706	283,308	287,172
Exhaust flow	m^3/hr at 395 °C	637,711	692,997	702,450
Stack height	m	44.91	44.91	44.91
Stack diameter	m	3.0	3.0	3.0
Exit velocity	m/s	25.1	27.2	27.6

Calculated Emissions	24 °C Ambient		4.4 °C Ambient		-5 °C Ambient	
Pollutant	lb/MMBtu (HHV)	lb/hr (per turbine)	lb/MMBtu (HHV)	lb/hr (per turbine)	lb/MMBtu (HHV)	lb/hr (per turbine)
CO2	117.0	39,526	117.0	43,595	117.0	42,927
CH4	0.0069	2.32	0.0261	9.7	0.0287	10.5
N2O	0.00022	0.074	0.00022	0.082	0.00022	0.081
CO2e	N/A	39,606	N/A	43,863	N/A	43,214

Hourly and Annual Totals	Worst-case lb/hr		Annual emissions, tons	
Pollutant	x1 turbine	x6 turbines	x1 turbine	x6 turbines
CO2	43,595	261,569	173,124	733,445
CH4	10.5	63.1	10.2	43.1
N2O	0.082	0.49	0.33	1.4
CO2e	43,863	263,175	173,476	734,935

Notes:
1) All vendor data shown are for 100% load, at 24 °C ambient temperature.
2) For annual emissions, it is assumed that operation is equivalent to two generation turbines per FLSO operating for 8,760 hours per year at full load, with the third turbine per FLSO operating for 1,036 hours per year at full load.
3) Annual potential tpy is based on 24 °C ambient case.
4) Worst-case short lb/hr occurs at 4.4 °C ambient case.
5) WHRU inlet and outlet temperatures based on proposal from Heat Recovery Solutions, November 21, 2012.
6) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (53.06 kg/MMBtu) and N2O (0.0001 kg/MMBtu).
7) CH4 emissions are based on the emission rate for unburned hydrocarbons (UHC), which is based on vendor concentration for UHC as methane equivalent ppmvd, minus the VOC emission rate, which is based on the AP-42 VOC emission factor in Table 3.1-2a.
8) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Lavaca Bay LNG Project
FLSO Essential Generators (x2 per FLSO)

Placeholder Engine Data

Make and model		MAN 12V32/40
Engine speed	rpm	720
Bore	mm	320
Stroke	mm	400
Displacement	L/cylinder	32.2
Fuel type		MGO or MDO
Fuel heat content	kJ/kg (LHV)	42700
Fuel density	kg/m3	890
Fuel sulfur content	% weight	0.0015
Conversion factor	Btu/kcal	3.97
Conversion factor	kJ/kcal	4.184

Tetra Tech assumptions/calculations

Engine load	%	100
Engine power output	kW/cylinder	480
Number of cylinders		12
Total engine output	kW	5,760
Generator efficiency	%	95
Generator output	kW	5,472
Specific fuel consumption	g/kWh	190
Heat input rate	MMBtu/hr (HHV)	47.1
EPA F-factor, Fd	dscf/MMBtu	9,190
EPA F-factor, Fw	wscf/MMBtu	10,320
Stoichiometric air requirement	kg/kWh	2.66
Specific air consumption	kg/kWh	7
Exhaust temperature	^{o}C	310
Volumetric flow for stoichiometric combustion	dscfh	433,163
Volumetric flow for stoichiometric combustion	wscfh	499,923
Volumetric flow for excess air	wscfh	737,540
Volumetric exhaust flow	m^3/hr (wet)	69,723
Stack height	m	55.15
Stack diameter	m	1.2
Exit velocity	m/s	17.1

Calculated Emissions		Short term emissions, lb/hr		Annual emissions, tons	
Pollutant	lb/MMBtu (HHV)	(per engine)	(x4 engines)	(per engine)	(x4 engines)
CO2	163.1	7,685	30,741	2,767	11,067
CH4	0.0066	0.31	1.25	0.11	0.45
N2O	0.0013	0.062	0.25	0.022	0.090
CO2e	N/A	7,712	30,847	2,776	11,105

Notes:
1) MDO heating value is assumed, based on the ISO 3046 fuel specification.
2) MDO Fw and Fd volumetric factors are based on EPA Method 19.
3) MDO density based on maximum specification for DMA fuel.
4) Engine power output per cylinder, specific fuel consumption, specific air consumption, and exhaust temperature are based on performance data from an STX-MAN B&W 8L32/40 engine.
5) Bore, stroke, and displacement per cylinder based on brochure for MAN 32/40 four-stroke diesel engines.
6) Stoichiometric air requirement is calculated based on a ratio of 14 lb air/lb oil, from Babcock & Wilcox, "Useful tables for engineers and steam users," 14th ed., 1984.
7) Heat input and volumetric exhaust flows are calculated. Stoichiometric wet exhaust flow uses Equation 19-2 from EPA Method 19, using Fw and 2.7% ambient moisture, at actual exhaust temperature. Stoichiometric dry exhaust flow uses Equation 19-1 from EPA Method 19, using Fd, at 273.15K and 101.3 kPa.
8) Volume of excess air (wscfm) = (actual air consumption - stoichiometric air requirement)*(0.00290 cf-atm/gmol-K)/(28.8 g/gmol)/(1 atm)*(293 K)*(1000 g/kg)*(engine output in kW)/(60 min/hour).
9) For annual emissions, it is assumed that each essential generator operates for the equivalent of 720 hours per year at full load.
10) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (73.96 kg/MMBtu), CH4 (0.003 kg/MMBtu) and N2O (0.0006 kg/MMBtu).
11) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Lavaca Bay LNG Project
FLSO Emergency Generator (x1 per FLSO)

Fuel Data

Fuel type		MGO or MDO
Fuel heat content	kJ/kg (LHV)	42700
Fuel density	kg/m3	890
Fuel sulfur content	% weight	0.0015
Conversion factor	Btu/kcal	3.97
Conversion factor	kJ/kcal	4.184
Conversion factor	HHV/LHV	1.063

Cummins Engine Data

Model		KTA50-DM1
Total displacement	L	50
Number of cylinders		16
Engine speed	rpm	1800
Rated power	kWm	1290
Fuel consumption at 100% load	kg/kW	0.207
Exhaust temperature at turbo outlet	^{o}C	446
Exhaust flow at actual temp	L/sec	4394

Tetra Tech assumptions/calculations

Engine load	%	100
Heat input rate	MMBtu/hr (HHV)	11.5
Volumetric exhaust flow	m^3/hr	15,818
Stack height	m	19.85
Stack diameter	m	0.50
Exit velocity	m/s	22.4

Calculated Emissions

		Short term emissions, lb/hr		Annual emissions, tons	
Pollutant	lb/MMBtu (HHV)	(per engine)	(x2 engines)	(per engine)	(x2 engines)
CO2	163.1	1,875	3,750	49	98
CH4	0.0066	0.076	0.15	2.0E-03	4.0E-03
N2O	0.0013	0.015	0.030	4.0E-04	7.9E-04
CO2e	N/A	1,882	3,763	49	98

Notes:
1) MDO heating value is assumed, based on the ISO 3046 fuel specification.
2) MDO density based on maximum specification for DMA fuel.
3) Engine power output, total displacement, specific fuel consumption, exhaust temperature, and exhaust flow are based on performance data from a Cummins KTA50-DM1 engine.
4) For annual emissions, it is assumed that each emergency generator operates for the equivalent of 52 hours per year at full load.
5) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (73.96 kg/MMBtu), CH4 (0.003 kg/MMBtu) and N2O (0.0006 kg/MMBtu).
6) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Lavaca Bay LNG Project
FLSO Fire Pump Engines (x2 per FLSO)

Fuel Data

Fuel type		MGO or MDO
Fuel heat content	kJ/kg (LHV)	42700
Fuel density	kg/m3	890
Fuel sulfur content	% weight	0.0015
Conversion factor	Btu/kcal	3.97
Conversion factor	kJ/kcal	4.184
Conversion factor	HHV/LHV	1.063

Cummins Engine Data

Model		QSK60-DM
Total displacement	L	60.2
Number of cylinders		16
Engine speed	rpm	1800
Rated power	kWm	1900
Fuel consumption at 100% load	kg/kW	0.215
Exhaust temperature at turbo outlet	^{o}C	418
Exhaust flow at actual temp	L/sec	6741

Tetra Tech assumptions/calculations

Engine load	%	100
Heat input rate	MMBtu/hr (HHV)	17.6
Volumetric exhaust flow	m^3/hr	24,268
Stack height	m	27.4
Stack diameter	m	0.50
Exit velocity	m/s	34.3

Calculated Emissions		Short term emissions, lb/hr		Annual emissions, tons	
Pollutant	lb/MMBtu (HHV)	(per engine)	(x4 engines)	(per engine)	(x4 engines)
CO2	163.1	2,869	11,475	75	298
CH4	0.0066	0.12	0.47	3.0E-03	0.012
N2O	0.0013	0.023	0.093	6.1E-04	2.4E-03
CO2e	N/A	2,878	11,514	75	299

Notes:
1) MDO heating value is assumed, based on the ISO 3046 fuel specification.
2) MDO density based on maximum specification for DMA fuel.
3) Engine power output, total displacement, specific fuel consumption, exhaust temperature, and exhaust flow are based on performance data from a Cummins QSK60-DM engine.
4) For annual emissions, it is assumed that each fire pump engine operates for the equivalent of 52 hours per year at full load.
5) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (73.96 kg/MMBtu), CH4 (0.003 kg/MMBtu) and N2O (0.0006 kg/MMBtu).
6) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Lavaca Bay LNG Project
FLSO Cold Flare (Normal Operation)

Each FLSO has one cold flare and one warm flare.
Each flare will operate continuously with a pilot flame for 8,760 hours/year.
Each flare is assumed to have one pilot burner.

Fuel flow rates

Cold flare purge gas	kg/hr	125
Cold flare pilot burner	kg/hr	80
Warm flare purge gas	kg/hr	125
Warm flare pilot burner	kg/hr	80

TCEQ Equations for Equivalent Stack Parameters

Sensible heat release	qn = q*(1 - 0.048*SQRT(MW))
Equivalent diameter	d = 0.001 * SQRT(qn)

Gas Properties and Calculated Heat Input

Flare gas MW	kg/kgmol	16.64
Flare gas GCV	Btu/scf (HHV)	1,044
VOC content	% weight	1.4%
C1, C2, C3 content	% weight	99.2%
Ideal gas volume at 20 °C (68 °F)	m3/kgmol	24.06
Cold flare fuel flow	kg	205
Cold flare fuel flow	scf/hr	10,466
Cold flare heat input	MMBtu/hr (HHV)	10.9

TCEQ Equivalent Stack Parameters (Cold Flare)

Conversion factor	cal/Btu	252
Gross heat release	q, cal/s	764,835
Sensible heat release	qn, cal/s	615,078
Mean MW of feed gas	MW, kg/kgmol	16.64
Equivalent diameter	d, m	0.8
Temperature	K	1,273
Exit velocity	m/s	20

Emission Factors

			Cold flare, lb/hr (per FLSO)	Cold flare annual tons (per FLSO)
CO2	lb/MMBtu (HHV)	117.0	1,278	5,598
CH4	lb/MMBtu (HHV)	0.4105	4.5	19.6
N2O	lb/MMBtu (HHV)	0.00022	2.4E-03	0.011
CO2e	lb/MMBtu (HHV)	N/A	1,391	6,092

Notes:
1) Pilot fuel and purge gas sent to each flare are assumed to have composition identical to "Net LNG to Storage" in Lavaca Bay LNG, Resource Report 13.
2) Molecular weight and gross calorific value of gas sent to flare are taken from Lavaca Bay LNG, Resource Report 13.
3) Flow rate of fuel gas to flare purge and pilot burner are based on email correspondence with Graeme Trotter of Excelerate Energy, May 1, 2014.
4) Equivalent stack parameters are calculated based on the TCEQ memo, "Technical Basis for Flare Parameters," September 10, 2004.
5) Emission factors for CO2 and N2O are from Tables C-1 and C-2 of 40 CFR 98, Subpart C.
6) CH4 emission factor rate assumes 99% destruction of C1, C2, and C3 compounds (CH4, C2H6, C3H8) present in gas sent to flare.
7) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Lavaca Bay LNG Project
FLSO Warm Flare (Normal Operation)

Each FLSO has one cold flare and one warm flare.
Each flare will operate continuously with a pilot flame for 8,760 hours/year.
Each flare is assumed to have one pilot burner.

Fuel flow rates

Cold flare purge gas	kg/hr	125
Cold flare pilot burner	kg/hr	80
Warm flare purge gas	kg/hr	125
Warm flare pilot burner	kg/hr	80

TCEQ Equations for Equivalent Stack Parameters

Sensible heat release	qn = q*(1 - 0.048*SQRT(MW))
Equivalent diameter	d = 0.001 * SQRT(qn)

Gas Properties and Calculated Heat Input

Flare gas MW	kg/kgmol	16.66
Flare gas GCV	Btu/scf (HHV)	1,042
VOC content	% weight	1.6%
C1, C2, C3 content	% weight	98.8%
Ideal gas volume at 20 °C (68 °F)	m3/kgmol	24.06
Warm flare fuel flow	kg	205
Warm flare fuel flow	scf/hr	10,453
Warm flare heat input	MMBtu/hr (HHV)	10.9

TCEQ Equivalent Stack Parameters (Warm Flare)

Conversion factor	cal/Btu	252
Gross heat release	q, cal/s	762,453
Sensible heat release	qn, cal/s	613,073
Mean MW of feed gas	MW, kg/kgmol	16.66
Equivalent diameter	d, m	0.8
Temperature	K	1,273
Exit velocity	m/s	20

Emission Factors

			Warm flare, lb/hr (per FLSO)	Warm flare annual tons (per FLSO)
CO2	lb/MMBtu (HHV)	117.0	1,274	5,581
CH4	lb/MMBtu (HHV)	0.4098	4.5	19.5
N2O	lb/MMBtu (HHV)	0.00022	2.4E-03	0.011
CO2e	lb/MMBtu (HHV)	N/A	1,386	6,072

Notes:
1) Pilot fuel and purge gas sent to each flare are assumed to have composition identical to "Treated Gas" in Lavaca Bay LNG, Resource Report 13.
2) Molecular weight and gross calorific value of gas sent to flare are taken from Lavaca Bay LNG, Resource Report 13.
3) Flow rate of fuel gas to flare purge and pilot burner are based on email correspondence with Graeme Trotter of Excelerate Energy, May 1, 2014.
4) Equivalent stack parameters are calculated based on the TCEQ memo, "Technical Basis for Flare Parameters," September 10, 2004.
5) Emission factors for CO2 and N2O are from Tables C-1 and C-2 of 40 CFR 98, Subpart C.
6) CH4 emission factor rate assumes 99% destruction of C1, C2, and C3 compounds (CH4, C2H6, C3H8) present in gas sent to flare.
7) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Lavaca Bay LNG Project
FLSO LNG Storage Tank Inspection Emissions

Reference values for calculations

Ideal gas volume at 20 °C (68 °F), 1 bar	m3/kgmol	24.06
Ideal gas volume at 30 °C (86 °F), 1 bar	m3/kgmol	24.88
Ideal gas volume at 50 °C (122 °F), 1 bar	m3/kgmol	26.52
Ideal gas volume at -140 °C (-220 °F), 1 bar	m3/kgmol	10.93
LNG storage tank volume	m3	25,100
LNG storage tank pressure	bar, absolute	1.06
LNG volume required for step 8 cooldown	m3	160
LNG density	kg/m3	424

Inert gas properties

			MW
N2	% volume	85.5	28.02
O2	% volume	0.5	32.00
CO2	% volume	14.0	44.01
H2O	% volume	0.0	18.02
NOx	ppmvd at 3% O2	150	
CO	ppmvd at 3% O2	100	
SO2	ppmvd at 3% O2	1	
Molecular weight	kg/kgmol	30.28	

Dry air properties

Molecular weight	kg/kgmol	28.96

LNG Storage Tank Vapor Composition

			MW
Nitrogen	mol %	0.120	28.02
Carbon Dioxide	mol %	0.000	44.01
Methane	mol %	96.430	16.04
Ethane	mol %	2.970	30.07
Propane (VOC)	mol %	0.330	44.1
i-Butane (VOC)	mol %	0.060	58.1
n-Butane (VOC)	mol %	0.050	58.1
i-Pentane (VOC)	mol %	0.020	72.2
n-Pentane (VOC)	mol %	0.010	72.2
n-Hexane (VOC, HAP)	mol %	0.010	86.1
VOC content	% weight	1.4%	
C1, C2, C3 content	% weight	99.2%	
Molecular weight	kg/kgmol	16.64	
Higher Heating Value (HHV)	Btu/scf at 20 °C	1,044	
Lower Heating Value (LHV)	Btu/scf at 20 °C	940	

Supplemental fuel flow rate (only supplied when gas is flared)

Pilot burner	kg/hr	80
Pilot burner	scf/hr	4,084
Pilot burner	MMBtu/hr (HHV)	4.3

Flaring emission factors

Pollutant	lb/MMBtu (HHV)
CO2	117.0
CH4	0.4105
N2O	0.00022
CO2e	N/A

Lavaca Bay LNG Project
FLSO LNG Storage Tank Inspection Emissions

Durations and gas flows during each step	Duration (hours)	Gas exhausts to:	Gas temp inside tank (°C)	Gas temp at tank inlet (°C)	Gas temp at vent/flare outlet (°C)	Gas m3/hr entering tank (at 1.06 bar)	Gas total m3 (at 1.06 bar)
Step 1: Warming Up	44	Flare	-140 --> 50	50	50	N/A	N/A
Step 2: Gas Freeing	9	Flare	50 --> 20	50	50	4,267	38,403
Step 2: Gas Freeing	1	Vent	20	20	20	4,267	4,267
Step 3: Aerating	10	Vent	20	20	20	4,267	42,670
Step 4: Tank inspection	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Step 5: Drying	10	Vent	20	20	20	4,769	47,690
Step 6: Inerting	10	Vent	20	20	20	4,267	42,670
Step 7: Gassing Up	1	Vent	20	20	20	4,267	4,267
Step 7: Gassing Up	9	Flare	20	20	20	4,267	38,403
Step 8: Cooling Down	10	Flare	20 --> -140	N/A	20	N/A	N/A

Mass flows during each step	Start mass LNG vapor in tank	End mass LNG vapor in tank	Start mass inert gas in tank	End mass inert gas in tank	Start mass dry air in tank	End mass dry air in tank	Total kg LNG vapor to vent/flare	Total kg inert gas to vent/flare	Total kg dry air to vent/flare
Step 1: Warming Up (to Flare)	40,520	16,696	0	0	0	0	23,824	0	0
Step 2: Gas Freeing (to Flare)	16,696	835	0	31,815	0	0	15,861	1,674	0
Step 2: Gas Freeing (to Vent)	835	0	31,815	33,490	0	0	835	4,019	0
Step 3: Aerating (to Vent)	0	0	33,490	0	0	32,031	0	33,490	22,422
Step 4: Tank inspection	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Step 5: Drying (to Vent)	0	0	0	0	32,031	32,031	0	0	0
Step 6: Inerting (to Vent)	0	0	0	33,490	32,031	0	0	23,443	32,031
Step 7: Gassing Up (to Vent)	0	920	33,490	31,815	0	0	2,031	1,674	0
Step 7: Gassing Up (to Flare)	920	18,404	31,815	0	0	0	10,675	31,815	0
Step 8: Cooling Down (to Flare)	18,404	40,520	0	0	0	0	45,724	0	0

Lavaca Bay LNG Project
FLSO LNG Storage Tank Inspection Emissions

LNG vapor/pilot fuel emissions during step (lbs):

Pollutant	1 (flare)	2 (flare)	2 (vent)	3 (vent)	5 (vent)	6 (vent)	7 (vent)	7 (flare)	8 (flare)
CO2	149,035	99,387	0	0	0	0	0	67,051	285,572
CH4	522.9	348.7	1,710.7	0	0	0	4,163	235.3	1,002.0
N2O	0.28	0.2	0	0	0	0	0	0.13	0.54
CO2e	162,192	108,161	42,767	0	0	0	104,073	72,970	310,783

Inert gas emissions during step (lbs):

Pollutant	1 (flare)	2 (flare)	2 (vent)	3 (vent)	5 (vent)	6 (vent)	7 (vent)	7 (flare)	8 (flare)
CO2	0	751	1,803	15,024	0	10,517	751	14,273	0
CH4	0	0	0	0	0	0	0	0	0
N2O	0	0	0	0	0	0	0	0	0
CO2e	0	751	1,803	15,024	0	10,517	751	14,273	0

Average hourly rate during step (lb/hr):

Pollutant	1 (flare)	2 (flare)	2 (vent)	3 (vent)	5 (vent)	6 (vent)	7 (vent)	7 (flare)	8 (flare)
CO2	3,387	11,126	1,803	1,502	0	1,052	751.2	9,036	28,557
CH4	11.9	38.7	1,710.7	0	0	0	4,163	26.1	100.2
N2O	6.4E-03	0.021	0	0	0	0	0	0.014	0.054
CO2e	3,686	12,101	44,570	1,502	0	1,052	104,824	9,694	31,078

Facility-wide annual total tons (2 tanks per FLSO per year)

Pollutant	All flare steps for 2 inspections (tpy)	All vent steps for 2 inspections (tpy)	Total per FLSO (tpy)	Total facility-wide (tpy)
CO2	616	28	644	1,288
CH4	2.1	5.9	8.0	16.0
N2O	1.1E-03	0	1.1E-03	2.3E-03
CO2e	669	175	844	1,688

Notes:
1) Each FLSO has ten LNG storage tanks, each with a capacity of 25,100 m3. Annual emissions assume that two LNG tanks on each FLSO will be emptied for inspection each year.
2) Durations, flow rates, and temperatures for each step are based on guidance provided by Gaztransport & Technigaz (GTT) in email correspondence, May-June 2014.
3) Required volumes assume a replacement ratio of 1.7 for steps 2, 3, 6, and 7; and a replacement ratio of 1.9 for step 5. The replacement ratio is the volume of gas introduced divided by the volume of the storage tank, and it represents minimal mixing of the gas layers through use of the "piston effect." Step 5 intoduces dry air into a tank filled with moist ambient air, and the nearly identical densities means a higher replacement ratio is required.
4) Hourly emission rates for each step of the tank clearing process are determined by dividing total emissions per step by the duration of each step in hours.
5) Inert gas composition for CO, SO2, N2, O2, CO2, and H2O taken from Aalborg technical proposal, Lavaca Bay LNG, Resource Report 13, Appendix M.2.2.7.
6) Inert gas is scrubbed with sea water, filtered, and dried prior to use, and is assumed to contain no CH4 or N2O.
7) Composition, molecular weight, and gross calorific value of vapor in empty LNG tank is based on data provided by Excelerate for "Net LNG to Storage" in Lavaca Bay LNG, Resource Report 13.
8) Dry air molecular weight based on guidance documents provided for the project by Gaztransport & Technigaz (GTT).
9) Liquid LNG volume of 160 m3 required for cooldown of one 25,100 m3 tank based on guidance provided by Gaztransport & Technigaz (GTT) in email correspondence, May-June 2014 .
10) Liquid LNG density of 424 kg/m3 based on guidance documents provided for the project by Gaztransport & Technigaz (GTT).
11) FLSO LNG storage tank volume is taken from Lavaca Bay LNG, Resource Report 13.
12) Flaring emission factors for CO2 and N2O are from Tables C-1 and C-2 of 40 CFR 98, Subpart C.
13) CH4 emission factor rate assumes 99% destruction of C1, C2, and C3 compounds (CH4, C2H6, C3H8) present in gas sent to flare.
14) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Lavaca Bay LNG Project
LNG Carrier Gas-In and Cooldown Emissions

Reference values for calculations

Ideal gas volume at 20 °C (68 °F), 1 bar	m3/kgmol	24.06
Ideal gas volume at 30 °C (86 °F), 1 bar	m3/kgmol	24.88
Ideal gas volume at 50 °C (122 °F), 1 bar	m3/kgmol	26.52
Ideal gas volume at -140 °C (-220 °F), 1 bar	m3/kgmol	10.93
LNGC total cargo capacity	m3	151,000
LNGC storage tank pressure	bar, absolute	1.06
LNG volume required for step 2 cooldown	m3	962.5
LNG density	kg/m3	424

Inert gas properties

			MW
N2	% volume	85.5	28.02
O2	% volume	0.5	32.00
CO2	% volume	14.0	44.01
H2O	% volume	0.0	18.02
NOx	ppmvd at 3% O2	150	
CO	ppmvd at 3% O2	100	
SO2	ppmvd at 3% O2	1	
Molecular weight	kg/kgmol	30.28	

Flaring emission factors

Pollutant	lb/MMBtu (HHV)
CO2	117.0
CH4	0.4105
N2O	0.00022
CO2e	N/A

LNG Storage Tank Vapor Composition

			MW
Nitrogen	mol %	0.120	28.02
Carbon Dioxide	mol %	0.000	44.01
Methane	mol %	96.430	16.04
Ethane	mol %	2.970	30.07
Propane (VOC)	mol %	0.330	44.1
i-Butane (VOC)	mol %	0.060	58.1
n-Butane (VOC)	mol %	0.050	58.1
i-Pentane (VOC)	mol %	0.020	72.2
n-Pentane (VOC)	mol %	0.010	72.2
n-Hexane (VOC, HAP)	mol %	0.010	86.1
VOC content	% weight	1.4%	
C1, C2, C3 content	% weight	99.2%	
Molecular weight	kg/kgmol	16.64	
Higher Heating Value (HHV)	Btu/scf at 20 °C	1,044	
Lower Heating Value (LHV)	Btu/scf at 20 °C	940	

Supplemental fuel flow rate (only supplied when gas is flared)

Pilot burner	kg/hr	80
Pilot burner	scf/hr	4,084
Pilot burner	MMBtu/hr (HHV)	4.3

Durations and gas flows during each step	Duration (hours)	Gas exhausts to:	Gas temp inside tank (°C)	Gas temp at tank inlet (°C)	Gas temp at vent/flare outlet (°C)	Gas m3/hr entering tank (at 1.06 bar)	Gas total m3 (at 1.06 bar)
Step 1: Gassing Up	1	Vent	20	20	20	12,835	12,835
Step 1: Gassing Up	19	Flare	20	20	20	12,835	243,865
Step 2: Cooling Down	10	Flare	20 --> -140	N/A	20	N/A	N/A

Mass flows during each step	Start mass LNG vapor in tank	End mass LNG vapor in tank	Start mass inert gas in tank	End mass inert gas in tank	Start mass dry air in tank	End mass dry air in tank	Total kg LNG vapor to vent/flare	Total kg inert gas to vent/flare
Step 1: Gassing Up (to Vent)	0	5,536	201,473	191,399	0	0	3,342	10,074
Step 1: Gassing Up (to Flare)	5,536	110,720	191,399	0	0	0	73,629	191,399
Step 2: Cooling Down (to Flare)	110,720	243,767	0	0	0	0	275,053	0

Lavaca Bay LNG Project

LNG Carrier Gas-In and Cooldown Emissions

	LNG vapor/pilot fuel emissions during step (lbs):			Inert gas emissions during step (lbs):			Average hourly rate during step (lb/hr):		
Pollutant	1 (vent)	1 (flare)	2 (flare)	1 (vent)	1 (flare)	2 (flare)	1 (vent)	1 (flare)	2 (flare)
CO2	0	459,547	1,715,349	4,519	85,863	0	4,519	28,706	171,535
CH4	6,849.6	1,612.5	6,019.0	0	0	0	6,849.6	84.9	601.9
N2O	0	0.87	3.23	0	0	0	0	0.046	0.32
CO2e	171,239	500,118	1,866,787	4,519	85,863	0	175,759	30,841	186,679

Facility-wide annual total tons (12 gas-ins and 20 cooldowns per year)

Pollutant	All flare steps for 12 gas-ins (tpy)	All vent steps for 12 gas-ins (tpy)	All flare steps for 20 cooldowns (tpy)
CO2	3,272	27	17,153
CH4	9.7	41.1	60.2
N2O	5.2E-03	0	0.032
CO2e	3,516	1,055	18,668

Total per FLSO (tpy)*	Total facility-wide (tpy)
10,227	20,453
55.5	111.0
0.019	0.038
11,619	23,238

* The full number of LNGC gas-ins and cooldowns may actually be distributed in any proportion between the two FLSOs.

Notes:

1) Annual emissions assume that up to 12 LNG carriers per year, with an average capacity of 151,000 m3, will arrive at the facility with empty cargo tanks containing inert gas, and will require gas-in with warm LNG vapor followed by cooling down, prior to receiving LNG cargo. It assumed that up to an additional 8 LNG carriers per year, with an average capacity of 151,000 m3, will arrive at the facility with empty cargo tanks containing warm methane, thus requiring only a cooldown prior to receiving LNG cargo. It is assumed that displaced gases will be routed to a flare or vent located on the FLSO.
2) Durations, flow rates, and temperatures for each step are based on guidance provided by Gaztransport & Technigaz (GTT) in email correspondence, May-June 2014.
3) Required gas-in volume assumes a replacement ratio of 1.7. The replacement ratio is the volume of gas introduced divided by the volume of the storage tank, and it represents minimal mixing of the gas layers through use of the "piston effect."
4) Hourly emission rates for each gas-in and cooldown step are determined by dividing total emissions per step by the duration of each step in hours.
5) All properties of inert gas inside tanks of arriving LNGCs has been assumed identical to the inert gas produced by the FLSO inert gas generator.
6) Inert gas composition for CO, SO2, N2, O2, CO2, and H2O taken from Aalborg technical proposal, Lavaca Bay LNG, Resource Report 13, Appendix M.2.2.7.
7) Inert gas NOx concentration based on typical IGG performance data.
8) Inert gas is scrubbed with sea water, filtered, and dried prior to use, and is assumed to contain no VOC, PM, HAP, Pb, H2SO4, CH4, or N2O.
9) Composition, molecular weight, and gross calorific value of LNG vapor in LNGC tanks is based on data provided by Excelerate for "Net LNG to Storage" in Lavaca Bay LNG, Resource Report 13.
10) Liquid LNG volume of 962.5 m3 required for cooldown of an entire 151,000 m3 LNG carrier is extrapolated from guidance provided by Gaztransport & Technigaz (GTT) for cooldown of a 25,100 m3 storage tank, in email correspondence, May-June 2014.
11) Liquid LNG density of 424 kg/m3 based on guidance documents provided for the project by Gaztransport & Technigaz (GTT).
12) Flaring emission factors for CO2 and N2O are from Tables C-1 and C-2 of 40 CFR 98, Subpart C.
13) CH4 emission factor rate assumes 99% destruction of C1, C2, and C3 compounds (CH4, C2H6, C3H8) present in gas sent to flare.
14) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Lavaca Bay LNG Project
Fugitives - FLSO
VOC and GHG Emission Calcs

Annual Hours of Operation	8,760
CH_4 constituent of the Nat Gas	92.81%
CO_2 constituent of the Nat Gas	0.00%

Component	Phase	No. of Components[1] (both FLSOs combined)	Emission Factor [2] (lb/hr-component)	Hourly Potential CO_2 Emissions (lb/hr) [4]	Annual Potential CO_2 Emissions (tpy) [5]	Hourly Potential CH_4 Emissions (lb/hr) [4]	Annual Potential CH_4 Emissions (tpy) [5]	Hourly Potential CO_2e Emissions (lb/hr) [6]	Annual Potential CO_2e Emissions (tpy) [6]
Valves	Gas/Vapor	3,792	0.00992	0.0	0.0	34.9	152.9	872.8	3,822.8
Flanges	Gas/Vapor	7,584	0.00086	0.0	0.0	6.1	26.5	151.3	662.8
Compressor Seals	Gas/Vapor	64	0.0194	0.0	0.0	1.2	5.0	28.8	126.2
Pumps	Light Liquid [8]	100	0.00529	0.0	0.0	0.49	2.2	12.3	53.8
Connectors	Gas/Vapor	300	0.00044	0.0	0.0	0.12	0.54	3.1	13.4
TOTAL		11,840		0.0	0.0	42.7	187.2	1,068.3	4,679.0

Component	Phase	No. of Components[1] (both FLSOs combined)	Control Efficiencies [28MID with AVO] (%) [7]	Hourly Controlled CO_2 Emissions (lb/hr) [4]	Annual Controlled CO_2 Emissions (tpy) [5]	Hourly Controlled CH_4 Emissions (lb/hr) [4]	Annual Controlled CH_4 Emissions (tpy) [5]	Hourly Controlled CO_2e Emissions (lb/hr) [6]	Annual Controlled CO_2e Emissions (tpy) [6]
Valves	Gas/Vapor	3,792	97	0.0	0.00	1.0	4.59	26.2	114.7
Flanges	Gas/Vapor	7,584	97	0.0	0.00	0.18	0.80	4.5	19.9
Compressor Seals	Gas/Vapor	64	95	0.0	0.00	0.06	0.25	1.4	6.3
Pumps	Light Liquid [8]	100	93	0.0	0.00	0.034	0.15	0.86	3.8
Connectors	Gas/Vapor	300	97	0.0	0.00	3.7E-03	0.016	0.092	0.40
TOTAL		11,840		0.00	0.00	1.32	5.80	33.1	145.0

[1] Component Counts are based on engineering design plans for the project.
[2] Leak emission factors are from EPA document EPA-453/R-95-017; November, 1995, Table 2-4, for total organic compound emissions, and converted to lb/hr/component as presented in TCEQ.
[3] Vapor components weight fractions are from estimated gas analysis provided by Excelerate.
[4] Emissions (lb/hr) = Emission factor (lb/hr/component) x Equipment Count x Constituent Wt % x (1 - control efficiency)
[5] Emissions (tpy) = Emissions (lb/hr/) x Annual Hours of Operation (hr/yr) / 2,000 (lb/ton)
[6] CO_2e emissions assume a global warming potential (GWP) of 1 for CO2, and 25 for CH4.
[7] Control efficiencies based on TCEQ Technical Guidance Document - Control Efficiencies for TCEQ Leak Detection and Repair Programs (Revised 07/11 (APDG 6129v2). Reduction credit for LDAR program 28 MID with AVO.
[8] CH_4 and CO_2 weight percent in liquid phase assumed to be the same as vapor phase

Treated Gas Composition

Vapor Component		Mole % [1]	Molecular Weight (lb/lb mole)	Average Molar Mass (lb/lbmole) [2]	Weight % [3]
Nitrogen	N2	0.250	28.02	0.0701	0.4205
Carbon Dioxide	CO2	0.000	44.01	0.0000	0.0000
Methane	CH4	96.400	16.04	15.4626	92.8092
Ethane	C2H6	2.840	30.07	0.8540	5.1258
Propane	C3H8	0.310	44.10	0.1367	0.8206
i-Butane	iC4H10	0.060	58.12	0.0349	0.2093
n-Butane	nC4H10	0.050	58.12	0.0291	0.1744
i-Pentane	iC5H12	0.020	72.15	0.0144	0.0866
n-Pentane	nC5H12	0.010	72.15	0.0072	0.0433
n-Hexane	nC6H14	0.060	86.18	0.0517	0.3104
Benzene	C6H6	0.000	78.11	0.0000	0.0000
n-Heptane (C7)	nC7H16	0.000	100.20	0.0000	0.0000
n-Octane (C8)	nC8H18	0.000	114.23	0.0000	0.0000
	Total	**100.000**		16.66	100
			VOC Wt %		1.6446
			HAP Wt %		0.3104
				Mol. Wt.:	16.66 kg/kmol
				HHV:	1042 Btu/scf
				LHV:	939 Btu/scf

[1] Mole percent for vapor components are from representative gas analysis.
[2] Average Molar Mass = ∑ (Mole fraction$_i$ x Molecular Weight).
[3] Weight Percent = Molecular Weight$_i$ / Average Molar Mass x 100%.

Lavaca Bay LNG Project
Onshore Power Generation Turbines (x7)

Placeholder Turbine Data from Technica (for Siemens SGT-400)

Case Number		1	2
Ambient temperature	°C	15	-3
Inlet temperature	°C	15	-3
Turbine shaft output	kW	13,439	14,038
Heat input	kW	37,639	38,448
Turbine heat rate	kJ/kWh	10,082	9,859
Generator output	kWe	12,905	13,481
Heat input	kW	37,639	38,448
Generator heat rate	kJ/kWeh	10,499	10,267
Exhaust flow	kg/s	40.56	43.13
Exhaust temperature	°C	553	515

Tetra Tech assumptions/calculations

GT heat input (per turbine)	MMBtu/hr (HHV)	142.4	145.5
Exhaust temperature (post-HRSG)	°C	140	140
Assumed exhaust MW	g/g-mol	28	28
Exhaust volumetric flow	Nm3/hr at 0 °C	116,813	124,214
Exhaust volumetric flow	m3/hr at 140 °C	176,684	187,879
Stack height	m	35.0	35.0
Stack exit velocity	m/s	27.4	29.1
Stack diameter	m	1.51	1.51

Calculated Emissions	15 °C Ambient		-3 °C Ambient	
Pollutant	lb/MMBtu (HHV)	lb/hr (per turbine)	lb/MMBtu (HHV)	lb/hr (per turbine)
CO2	117.0	16,661	117.0	17,020
CH4	0.0022	0.31	0.0022	0.32
N2O	0.00022	0.031	0.00022	0.032
CO2e	N/A	16,679	N/A	17,037

Hourly and Annual Emission Totals	Worst-case lb/hr		Annual emissions, tons	
Pollutant	x1 turbine	x7 turbines	x1 turbine	x6 turbines
CO2	17,020	119,137	72,977	437,864
CH4	0.32	2.2	1.4	8.3
N2O	0.032	0.22	0.14	0.83
CO2e	17,037	119,260	73,053	438,316

Notes:
1) Placeholder turbine data are from Technica, Electrical Scope of Works, 06120600-E-0105-002_R0, January 22, 2013.
2) All vendor data shown are from case number 1, at 15 °C ambient temperature .
3) Vendor heat inputs and heat rates are presumed to be based on the lower heating value (LHV) of natural gas.
4) Annual emissions are based on the equivalent of 6 combustion turbines operating for 8,760 hours per year at full load, with the seventh combustion turbine offline.
5) Annual potential tpy is based on 24 °C ambient case.
6) Worst-case short lb/hr for all pollutants occurs at -3 °C ambient case.
7) 40 CFR 98 emission factors are used to calculate emission rates for CO_2 (53.06 kg/MMBtu), CH_4 (0.001 kg/MMBtu) and N_2O (0.0001 kg/MMBtu).
8) CO_2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH_4, and 298 for N_2O.

Lavaca Bay LNG Project
Onshore Steam Boilers (x2)

Placeholder Data from Technica

Heat input rate	MMBtu/hr (HHV)	215.7
Fuel type	Natural gas	
EPA F-factor, Fd	dscf/MMBtu	8,710
EPA F-factor, Fw	wscf/MMBtu	10,610

Tetra Tech assumptions/calculations

Natural gas heat content	Btu/scf (HHV)	1,020
Exhaust moisture	% volume	17.9%
Dry exhaust O2	% volume	3.0
Wet exhaust O2	% volume	2.5
Exhaust temperature	°C	275
Exhaust volumetric flow	acfh	5,005,287
Exhaust volumetric flow	m3/hr at 275 °C	141,733
Stack height	m	35.0
Stack exit velocity	m/s	21.2
Stack diameter	m	1.54

Hourly and Annual Emission Totals		Short-term emissions, lb/hr		Annual emissions, tons	
Pollutant	lb/MMBtu (HHV)	(per boiler)	(x2 boilers)	(per boiler)	(x2 boilers)
CO2	117.0	25,232	50,463	110,514	221,029
CH4	0.0022	0.48	1.0	2.1	4.2
N2O	0.00022	0.048	0.10	0.21	0.42
CO2e	N/A	25,258	50,515	110,628	221,257

Notes:
1) Heat input rate is based on Technica, Equipment Emissions List, E-06120600-G-0400-002_R0, March 28, 2013.
2) Natural gas heat content is a default value from EPA AP-42.
3) Exhaust moisture content is estimated using F-factors from EPA Method 19.
4) Dry exhaust O2 content is assumed based on typical boiler performance.
5) Volumetric exhaust flow is calculated usingEquation 19-2 from EPA Method 19, using Fw and 2.7% ambient moisture, at actual exhaust temperature and wet O2 concentration.
6) Exhaust temperature and exit velocity are assumed values based on a typical mid-size boiler.
7) Annual emissions are based on operation for 8,760 hours per year at full load.
8) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (53.06 kg/MMBtu), CH4 (0.001 kg/MMBtu) and N2O (0.0001 kg/MMBtu).
9) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Lavaca Bay LNG Project
Onshore Thermal Oxidizers (x2)

Inlet and Outlet Exhaust Data from Black & Veatch		Inlet	Outlet
Exhaust temperature	°C	64	800
Mass flow	kg/hr	23767	46,351
Volumetric flow	m3/hr	10255	109,098
N2	kgmole/hr	0.00	546.95
O2	kgmole/hr	0.00	40.96
CO2	kgmole/hr	502.63	604.6
H2O	kgmole/hr	88.50	172.37
CH4	kgmole/hr	2.95	0.00
SO2	kgmole/hr	0.00	0.15
H2S	kgmole/hr	0.15	0.00
Total molar flow	kgmole/hr	594.23	1,365.03

Tetra Tech assumptions/calculations

Feed gas MW	kg/kg-mol	17.02
Feed gas heat content	Btu/scf (HHV)	1,025
Supplemental fuel firing	kg/hr	1,740
Supplemental fuel firing	scf/hr	86,796
Supplemental heat input	MMBtu/hr (HHV)	89.0
Percent destruction of CH4	%	99.9
Exhaust moisture	% volume	12.6
Exhaust O2 concentration	% volume, wet	3.0
Exhaust O2 concentration	% volume, dry	3.4
Exhaust volumetric flow	m3/hr	109,098
Stack height	m	35
Stack exit velocity	m/s	38.6
Stack diameter	m	1.0

		Short-term emissions, lb/hr		Annual emissions, tons	
Hourly and Annual Emission Totals	ppmvd at 3% O2	(per oxidizer)	(x2 oxidizers)	(per oxidizer)	(x2 oxidizers)
CO2	N/A	58,661	117,322	256,935	513,870
CH4	N/A	0.30	0.60	1.3	2.6
N2O	N/A	0.020	0.039	0.086	0.17
CO2e	N/A	58,674	117,349	256,994	513,987

Notes:
1) Outlet exhaust data taken from Black & Veatch, Material Balance (On-Shore), 177377-0000-P1200 Rev 0, December 26, 2012.
2) Feed gas molecular weight and heat content for supplemental firing taken from Lavaca Bay LNG, Resource Report 13.
3) Supplementary fuel firing rate taken from Black & Veatch, Utility Summary, 177377.57.8300 Rev 0, December 21, 2012.
4) CO2 emission rate is based on outlet exhaust data provided by Black & Veatch.
5) CH4 emission rate is based on 99.9% control of inlet CH4 flow rate provided by Black & Veatch, plus CH4 produced by supplemental firing.
6) For supplemental fuel firing only, 40 CFR 98 emission factors are used to calculate emission rates for CH4 (0.001 kg/MMBtu) and N2O (0.0001 kg/MMBtu).
7) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Lavaca Bay LNG Project
Onshore Regeneration Gas Heaters (x2)

Placeholder Data from Technica

Heat input rate	MMBtu/hr (HHV)	47.6
Fuel type	Natural gas	
EPA F-factor, Fd	dscf/MMBtu	8,710
EPA F-factor, Fw	wscf/MMBtu	10,610

Tetra Tech assumptions/calculations

Natural gas heat content	Btu/scf (HHV)	1,020
Exhaust moisture	% volume	17.9%
Dry exhaust O2	% volume	3.0
Wet exhaust O2	% volume	2.5
Exhaust temperature	°C	275
Exhaust volumetric flow	acfh	1,104,551
Exhaust volumetric flow	m3/hr at 275 °C	31,277
Stack height	m	35.0
Stack exit velocity	m/s	21.2
Stack diameter	m	0.72

Calculated emissions		Short-term emissions, lb/hr		Annual emissions, tons	
Pollutant	lb/MMBtu (HHV)	(per heater)	(x2 heaters)	(per heater)	(x2 heaters)
CO2	117.0	5,568	11,136	24,388	48,776
CH4	0.0022	0.10	0.21	0.46	0.92
N2O	0.00022	0.01	0.021	0.046	0.092
CO2e	N/A	5,574	11,148	24,413	48,826

Notes:
1) Heat input rate is based on Technica, Equipment Emissions List, E-06120600-G-0400-002_R0, March 28, 2013.
2) Natural gas heat content is a default value from EPA AP-42.
3) Exhaust moisture content is estimated using F-factors from EPA Method 19.
4) Dry exhaust O2 content is assumed based on typical boiler performance.
5) Volumetric exhaust flow is calculated usingEquation 19-2 from EPA Method 19, using Fw and 2.7% ambient moisture, at actual exhaust temperature and wet O2 concentration.
6) Exhaust temperature and exit velocity are assumed values based on a typical mid-size boiler.
7) Annual emissions are based on operation for 8,760 hours per year at full load.
8) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (53.06 kg/MMBtu), CH4 (0.001 kg/MMBtu) and N2O (0.0001 kg/MMBtu).
9) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Lavaca Bay LNG Project
Onshore Emergency Generators (x2)

Fuel Data

Fuel type		MGO or MDO
Fuel heat content	kJ/kg (LHV)	42,700
Fuel density	kg/m3	890
Fuel sulfur content	% weight	0.0015
Conversion factor	Btu/kcal	3.97
Conversion factor	kJ/kcal	4.184
Conversion factor	HHV/LHV	1.063

Placeholder Caterpillar Engine Data

Model		C175-16
Total displacement	L	84.67
Number of cylinders		16
Engine speed	rpm	1,800
Rated power	ekW	3,000
Fuel consumption at 100% load	L/hr	810.7
Exhaust temperature	^{o}C	478
Exhaust flow at actual temp	m^3/min	725.6

Tetra Tech assumptions/calculations

Engine load	%	100
Heat input rate	MMBtu/hr (HHV)	31.1
Volumetric exhaust flow	m^3/hr	43,536
Stack height	m	24.0
Stack diameter	m	0.70
Exit velocity	m/s	31.4

Calculated emissions		Short-term emissions, lb/hr		Annual emissions, tons	
Pollutant	lb/MMBtu (HHV)	(per engine)	(x2 engines)	(per engine)	(x2 engines)
CO2	163.1	5,067	10,134	253	507
CH4	0.0066	0.21	0.41	0.010	0.021
N2O	0.0013	0.041	0.082	2.1E-03	4.1E-03
CO2e	N/A	5,084	10,168	254	508

Notes:
1) MDO heating value is assumed, based on the ISO 3046 fuel specification.
2) MDO density based on maximum specification for DMA fuel.
3) Engine power output, total displacement, fuel consumption, exhaust temperature, and exhaust flow are based on performance data from a Caterpillar C175-16 engine.
4) For annual emissions, it is assumed that each emergency generator operates for the equivalent of 100 hours per year at full load.
5) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (73.96 kg/MMBtu), CH4 (0.003 kg/MMBtu) and N2O (0.0006 kg/MMBtu).
6) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Lavaca Bay LNG Project
Onshore Fire Pump Engine (x1)

Fuel Data

Fuel type		MGO or MDO
Fuel heat content	kJ/kg (LHV)	42,700
Fuel density	kg/m3	890
Fuel sulfur content	% weight	0.0015
Conversion factor	Btu/kcal	3.97
Conversion factor	kJ/kcal	4.184
Conversion factor	HHV/LHV	1.063

Placeholder Cummins Engine Data

Model		CFP7E-F30
Total displacement	L	6.7
Number of cylinders		6
Engine speed	rpm	1,900
Rated power	kWm	142
Fuel consumption at 100% load	L/hr	37.1
Exhaust temperature	^{o}C	442
Exhaust flow at actual temp	L/sec	557

Tetra Tech assumptions/calculations

Engine load	%	100
Heat input rate	MMBtu/hr (HHV)	1.4
Volumetric exhaust flow	m^3/hr	2,005
Stack height	m	6.0
Stack diameter	m	0.15
Exit velocity	m/s	31.5

Calculated emissions

Pollutant	lb/MMBtu (HHV)	Short term emissions, lb/hr (x1 engine)	Annual emissions, tons (x1 engine)
CO2	163.1	232	6
CH4	0.0066	9.4E-03	2.4E-04
N2O	0.0013	1.9E-03	4.9E-05
CO2e	N/A	233	6

Notes:
1) MDO heating value is assumed, based on the ISO 3046 fuel specification.
2) MDO density based on maximum specification for DMA fuel.
3) Engine power output, total displacement, specific fuel consumption, exhaust temperature, and exhaust flow are based on performance data from a Cummins CFP7E-F30 engine.
4) For annual emissions, it is assumed that the fire pump engine operates for the equivalent of 52 hours per year at full load.
5) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (73.96 kg/MMBtu), CH4 (0.003 kg/MMBtu) and N2O (0.0006 kg/MMBtu).
6) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Lavaca Bay LNG Project
Onshore Ground Flare Emissions

Release Quantity

Total release volume	Nm3/hr at 15 °C	90,657
Total release volume plus 20%	Nm3/hr at 15 °C	108,788
Total release mass	kg	59,833
Total release mass plus 20%	kg	71,800
Assumed release duration	hours	12

Calculated Heat Input

Feed gas MW	kg/kgmol	17.02
Feed gas GCV	Btu/scf (HHV)	1,025
VOC content	% weight	1.6%
C1, C2, C3 content	% weight	95.4%
Ideal gas volume at 20 °C (68 °F)	m3/kgmol	24.06
Maximum 1-hour flow	kg	5,983
Maximum 1-hour flow	scf	298,641
Maximum 1-hour heat input	MMBtu/hr (HHV)	306
Total event flow	kg	71,800
Total event flow	scf	3,583,696
Total event heat input	MMBtu (HHV)	3,673

Emission Factors

CO2	lb/MMBtu (HHV)	117.0
CH4	lb/MMBtu (HHV)	0.4110
N2O	lb/MMBtu (HHV)	0.00022

TCEQ Equations for Equivalent Stack Parameters

Sensible heat release	qn = q*(1 - 0.048*SQRT(MW))
Equivalent diameter	d = 0.001 * SQRT(qn)

TCEQ Equivalent Stack Parameters

Conversion factor	cal/Btu	252
Gross heat release	q, cal/s	21,427,513
Sensible heat release	qn, cal/s	17,184,320
Mean MW of feed gas	MW, kg/kgmol	17.02
Equivalent diameter	d, m	4.1
Temperature	K	1,273
Exit velocity	m/s	20

	Short term emissions, lb/hr (per flare)	Annual emissions, tons (x1 flare)
CO2	35,807	215
CH4	125.8	0.75
N2O	0.067	4.0E-04
CO2e	38,972	234

Notes:
1) Gas sent to ground flare are assumed to have composition identical to "Feed Gas" in Lavaca Bay LNG, Resource Report 13.
2) Feed gas molecular weight and gross calorific value are taken from Lavaca Bay LNG, Resource Report 13.
3) Total release volume and mass are for controlled depressurization of one pre-treatment train, as estimated by Technica (06/24/13 email).
4) Hourly and annual emissions are based on assuming one controlled release per year for maintenance.
5) Equivalent stack parameters are calculated based on the TCEQ memo, "Technical Basis for Flare Parameters," September 10, 2004.
6) Emission factors for CO2 and N2O are from Tables C-1 and C-2 of 40 CFR 98, Subpart C.
7) CH4 emission factor rate assumes 99% destruction of C1, C2, and C3 compounds (CH4, C2H6, C3H8) present in gas sent to flare.
8) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Lavaca Bay LNG Project
Onshore - Natural Gas Piping Fugitives
VOC and GHG Emission Calcs

Annual Hours of Operation	8,760
CH_4 constituent of the Nat Gas	89.63%
CO_2 constituent of the Nat Gas	3.46%

Component	Phase	No. of Components[1] (both phases combined)	Emission Factor [2] (lb/hr-component)	Hourly Potential CO_2 Emissions (lb/hr) [4]	Annual Potential CO_2 Emissions (tpy) [5]	Hourly Potential CH_4 Emissions (lb/hr) [4]	Annual Potential CH_4 Emissions (tpy) [5]	Hourly Potential CO_2e Emissions (lb/hr) [6]	Annual Potential CO_2e Emissions (tpy) [6]
Valves	Gas/Vapor	3,000	0.00992	1.0	4.5	26.7	116.8	667.8	2,925.2
Flanges	Gas/Vapor	6,000	0.00086	0.18	0.78	4.6	20.3	115.8	507.2
Compressor seals	Gas/Vapor	10	0.0194	0.007	0.029	0.17	0.76	4.4	19.1
Pumps	Light Liquid [8]	20	0.00529	3.7E-03	0.016	0.095	0.42	2.4	10.4
Connectors	Gas/Vapor	1,560	0.00044	0.024	0.10	0.62	2.7	15.4	67.5
TOTAL		10,590		1.2	5.4	32.2	141.0	805.8	3,529.3

Component	Phase	No. of Components[1] (both phases combined)	Control Efficiencies [28MID with AVO] (%) [7]	Hourly Controlled CO_2 Emissions (lb/hr) [4]	Annual Controlled CO_2 Emissions (tpy) [5]	Hourly Controlled CH_4 Emissions (lb/hr) [4]	Annual Controlled CH_4 Emissions (tpy) [5]	Hourly Controlled CO_2e Emissions (lb/hr) [6]	Annual Controlled CO_2e Emissions (tpy) [6]
Valves	Gas/Vapor	3,000	97	0.031	0.14	0.80	3.5	20.0	87.8
Flanges	Gas/Vapor	6,000	97	5.4E-03	0.023	0.14	0.61	3.5	15.2
Compressor seals	Gas/Vapor	10	95	3.4E-04	1.5E-03	8.7E-03	0.038	0.22	1.0
Pumps	Light Liquid [8]	20	93	2.6E-04	1.1E-03	6.6E-03	0.029	0.17	0.73
Connectors	Gas/Vapor	1,560	97	7.1E-04	3.1E-03	0.018	0.081	0.46	2.0
TOTAL		10,590		0.038	0.16	1.0	4.3	24.4	106.7

[1] Component Counts are based on engineering design plans for the project.

[2] Leak emission factors are from EPA document EPA-453/R-95-017; November, 1995, Table 2-4, for total organic compound emissions, and converted to lb/hr/component as presented in TCEQ.

[3] Vapor components weight fractions are from estimated gas analysis provided by Excelerate.

[4] Emissions (lb/hr) = Emission factor (lb/hr/component) x Equipment Count x Constituent Wt % x (1 - control efficiency)

[5] Emissions (tpy) = Emissions (lb/hr/) x Annual Hours of Operation (hr/yr) / 2,000 (lb/ton)

[6] CO_2e emissions assume a global warming potential (GWP) of 1 for CO2, and 25 for CH4.

[7] Control efficiencies based on TCEQ Technical Guidance Document - Control Efficiencies for TCEQ Leak Detection and Repair Programs (Revised 07/11 (APDG 6129v2). Reduction credit for LDAR program 28 MID with AVO.

[8] CH_4 and CO_2 weight percent in liquid phase assumed to be the same as vapor phase

Feed Gas Composition[1]

Vapor Component		Mole % [2]	Molecular Weight (lb/lb mole)	Average Molar Mass (lb/lbmole) [3]	Weight % [4]
Nitrogen	N2	0.244	28.02	0.0684	0.4016
Carbon Dioxide	CO2	1.340	44.01	0.5897	3.4645
Methane	CH4	95.115	16.04	15.2564	89.6261
Ethane	C2H6	2.800	30.07	0.8420	4.9462
Propane	C3H8	0.310	44.10	0.1367	0.8031
i-Butane	iC4H10	0.060	58.12	0.0349	0.2049
n-Butane	nC4H10	0.050	58.12	0.0291	0.1707
i-Pentane	iC5H12	0.020	72.15	0.0144	0.0848
n-Pentane	nC5H12	0.013	72.15	0.0094	0.0551
n-Hexane	nC6H14	0.048	86.18	0.0414	0.2430
Benzene	C6H6	0.000	78.11	0.0000	0.0000
n-Heptane (C7)	nC7H16	0.000	100.20	0.0000	0.0000
n-Octane (C8)	nC8H18	0.000	114.23	0.0000	0.0000
	Total	**100.000**		17.02	100
			VOC Wt %		1.5616
			HAP Wt %		0.2430
				Mol. Wt.:	17.02 kg/kmol
				HHV:	1025 Btu/scf
				LHV:	926 Btu/scf

[1] The on-shore fugitive sources will be assumed to contain untreated feed gas.

[2] Mole percent for vapor components are from representative gas analysis.

[3] Average Molar Mass = ∑ (Mole fraction$_i$ x Molecular Weight).

[4] Weight Percent = Molecular Weight$_i$ / Average Molar Mass x 100%.

Lavaca Bay LNG Project
Composition Data for Feed Gas, Treated Gas, LNG, and Hydrocarbon Condensates

Component	Formula	Molecular Weight (kg/kgmol)	Feed Gas Mole %	Treated Gas Mole %	LNG to Storage Mole %	Net LNG to Storage Mole %	Hydrocarbon Condensate Mole %
Nitrogen	N2	28.02	0.244	0.250	0.080	0.120	0.00
Carbon Dioxide	CO2	44.01	1.340	0.000	0.000	0.000	0.00
Methane	CH4	16.04	95.115	96.400	96.400	96.430	0.00
Ethane	C2H6	30.07	2.800	2.840	3.030	2.970	0.05
Propane	C3H8	44.10	0.310	0.310	0.340	0.330	0.70
i-Butane	iC4H10	58.12	0.060	0.060	0.060	0.060	3.55
n-Butane	nC4H10	58.12	0.050	0.050	0.050	0.050	7.15
i-Pentane	iC5H12	72.15	0.020	0.020	0.020	0.020	10.49
n-Pentane	nC5H12	72.15	0.013	0.010	0.010	0.010	8.45
n-Hexane	nC6H14	86.18	0.048	0.060	0.010	0.010	27.54
Benzene	C6H6	78.11	0.000	0.000	0.000	0.000	2.21
n-Heptane	nC7H16	100.20	0.000	0.000	0.000	0.000	26.09
n-Octane	nC8H18	114.23	0.000	0.000	0.000	0.000	13.34
n-Nonane	nC9H20	128.26	0.000	0.000	0.000	0.000	0.32
n-Decane	nC10H22	142.28	0.000	0.000	0.000	0.000	0.11
		Total	**100.000**	**100.000**	**100.000**	**100.000**	**100.00**
		Mol. Wt.	**17.02 kg/kmol**	**16.66 kg/kmol**	**16.63 kg/kmol**	**16.64 kg/kmol**	**87.63 kg/kmol**
		HHV	**1,025 Btu/scf**	**1,042 Btu/scf**	**1,043 Btu/scf**	**1,044 Btu/scf**	**4,819 Btu/scf**
		LHV	**926 Btu/scf**	**939 Btu/scf**	**940 Btu/scf**	**940 Btu/scf**	**4,466 Btu/scf**

Notes:
1) Mole fractions, average molecular weight, HHV, and LHV for feed gas, treated gas, LNG to storage, and net LNG to storage are taken from Lavaca Bay LNG, Resource Report 13.
2) Mole fractions for hydrocarbon condensate were provided by Excelerate in document "E-06120600-G-0400-001_R0 Equipment Emissions List - RTO Comments.xls."
3) Average molecular weight, HHV, and LHV for hydrocarbon condensate are taken from Lavaca Bay LNG, Resource Report 13.

APPENDIX C
Equipment Performance Data

Excelerate Energy, Lavaca Bay, OG2668

Industrial Trent Mechanical Drive, Wet Low Emissions Combustion system

Based on performance model eTrent v7.3.0

Metric Units	
Loss reference case	0
Fuel Temperature °C	50.0

Offloading Fuel Constituents

97.19% Methane (CH_4)
.310% Ethane (C_2H_6)
.050% Propane (C_3H_8)
2.44% Nitrogen (N_2)

	Parameters:		Ref	Guarantee	Nominal, Baseload, 3307 rpm, Offloading Fuel										
	Case number		0	10	1	2	3	4	5	6	7	8	9	10	11
	Load Condition	% Base	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Ambient Conditions	Altitude	m	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
	Barometric Pressure	kPa	101.325	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846
	Ambient Temperature	°C	15.0	34.0	-10.0	-5.0	0.0	5.0	10.0	15.0	20.0	25.0	30.0	34.0	41.0
	Ambient Relative Humidity	%	60.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Installation Losses	Inlet Loss	mm H_2O	101.60	85.56	104.77	103.14	101.56	100.04	98.49	96.99	95.26	93.17	89.12	85.56	79.16
	Exhaust Loss	mm H_2O	203.20	163.89	209.84	207.17	204.60	202.11	199.46	196.91	191.75	185.00	172.84	163.89	149.00
	Auxiliary Electrical Power Offtake	kWe	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inlet Air Conditioning	Air Cooling Type		None	None	None	None	None	None	None	None	None	None	None	None	None
	Cooler Operative?		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Cooler Water Flow	kg/hr	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Air Temperature	°C	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Relative Humidity	%	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Wet Compression Operative?		Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
	Wet Compression Water Flow	kg/hr	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Engine Inlet Air Flow	kg/s	156.2		165.9	163.0	160.2	157.5	154.8	152.1	149.3	146.2	141.5	137.5	130.2
Performance	Engine Output Shaft Speed	rpm	3400.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0
	Power kW	Engine Shaft	59001.0	47213.0	59001.0	59001.0	59001.0	59001.0	59001.0	59001.0	57732.0	55646.0	51466.0	48976.0	45132.0
	Heat Rate (kJ/KWH, LHV)	Engine Shaft	8661.0	9229.0	8628.2	8669.0	8709.8	8751.6	8785.3	8819.9	8690.0	8755.0	8883.0	8960.0	9091.0
	Efficiency % (LHV basis)	Engine Shaft	41.57	39.01	42.56	42.36	42.16	41.96	41.80	41.63	41.43	41.12	40.53	40.18	39.60
Combustion	GT Fuel Flow	kg/hr	10667.0		10418.0	10467.0	10517.0	10567.0	10608.0	10650.0	10472.0	10169.0	9543.0	9160.0	8565.0
	Fuel energy flow (LHV basis)	kW	141816.1		138512.1	139162.5	139829.7	140495.1	141037.8	141589.6	139231.3	135200.9	126880.1	121786.1	113873.0
	Combustor Water Injection Flow	kg/hr	12538.0		11006.0	11351.0	11698.0	12005.0	12148.0	12224.0	11846.0	11180.0	9906.0	8935.0	7119.0
Exhaust Composition	Exhaust Flow	kg/s	161.5		170.6	167.9	165.2	162.6	160.0	157.4	154.5	151.1	145.9	141.6	133.7
	Exhaust Temperature	°C	430.6		379.9	391.8	403.6	415.5	427.6	439.9	446.2	449.9	448.4	451.3	459.8
	Exhaust N_2	mol %	72.334		73.506	73.280	73.019	72.724	72.406	72.030	71.696	71.327	70.971	70.526	69.432
	Exhaust O_2	mol %	13.237		13.983	13.808	13.623	13.429	13.230	13.014	12.921	12.881	12.973	12.931	12.727
	Exhaust CO_2	mol %	3.106		2.891	2.948	3.005	3.062	3.119	3.176	3.178	3.149	3.055	3.016	2.971
	Exhaust Water	mol %	10.456		8.739	9.086	9.477	9.913	10.378	10.917	11.346	11.789	12.151	12.682	14.038
	GT Exhaust Argon	mol %	0.864		0.878	0.876	0.873	0.869	0.865	0.861	0.857	0.852	0.848	0.843	0.830
	GT Neon	mol %	0.003		0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Nominal Exhaust Emissions	NOx	ppmvd 15 % O_2	25.0		25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
		mg/m^3 15 % O_2	51.4		51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4
		kg/hr	22.3		21.8	21.9	22.0	22.1	22.2	22.3	22.0	21.3	20.1	19.3	18.1
	CO	ppmvd 15 % O_2	0.0		84.7	77.3	70.6	64.4	58.9	54.0	50.8	48.3	47.2	46.5	45.4
		mg/Nm^3 15 % O_2	0.0		105.9	96.6	88.2	80.5	73.7	67.6	63.5	60.4	59.0	58.1	56.7
		kg/hr	0.0		44.8	41.2	37.8	34.7	31.9	29.4	27.2	25.1	23.1	21.8	19.9
	UHC (methane equivalent)	ppmvd 15 % O_2	0.0		16.9	15.5	14.1	12.9	11.8	10.8	10.2	9.7	9.4	9.3	9.1
		mg/Nm^3 15 % O_2	0.0		12.1	11.1	10.1	9.2	8.5	7.7	7.3	6.9	6.8	6.7	6.5
	VOC (methane equivalent)	ppmvd 15 % O_2	0.0		3.4	3.1	2.8	2.6	2.4	2.2	2.0	1.9	1.9	1.9	1.8
		mg/Nm^3 15 % O_2	0.0		2.4	2.2	2.0	1.8	1.7	1.5	1.5	1.4	1.4	1.3	1.3
	SOx (SO_2 equivalent)	ppmvd 15 % O_2	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		mg/Nm^3 15 % O_2	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		kg/hr	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Excelerate Energy, Lavaca Bay, OG2668

Industrial Trent Mechanical Drive, Wet Low Emissions Combustion system

Based on performance model eTrent v7.3.0

Metric Units	
Loss reference case	0
Fuel Temperature °C	50.0

Offloading Fuel Constituents

97.19% Methane (CH4)
.310% Ethane (C2H6)
.050% Propane (C3H8)
2.44% Nitrogen (N2)

	Parameters:		Ref	Nominal, 44790kW, 3307 rpm, Offloading Fuel										
	Case number		0	12	13	14	15	16	17	18	19	20	21	22
	Load Condition	% Base	100.00	75.91	75.91	75.91	75.91	75.91	75.91	77.58	80.49	87.03	91.45	99.24
Ambient Conditions	Altitude	m	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
	Barometric Pressure	kPa	101.325	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846
	Ambient Temperature	°C	15.0	-10.0	-5.0	0.0	5.0	10.0	15.0	20.0	25.0	30.0	34.0	41.0
	Ambient Relative Humidity	%	60.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Installation Losses	Inlet Loss	mm H_2O	101.60	86.23	85.14	84.03	82.91	82.47	82.11	81.73	81.02	80.24	79.67	78.69
	Exhaust Loss	mm H_2O	203.20	162.55	160.67	158.74	156.83	155.85	154.97	154.04	152.68	151.19	150.03	147.93
	Auxiliary Electrical Power Offtake	kWe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inlet Air Conditioning	Air Cooling Type		None	None	None	None	None	None	None	None	None	None	None	None
	Cooler Operative?		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Cooler Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Air Temperature	°C	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Relative Humidity	%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Wet Compression Operative?		Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
	Wet Compression Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Engine Inlet Air Flow	kg/s	156.2	150.5	148.1	145.7	143.4	141.6	140.0	138.3	136.3	134.3	132.7	129.8
Performance	Engine Output Shaft Speed	rpm	3400.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0
	Power kW	Engine Shaft	59001.0	44790.0	44790.0	44790.0	44790.0	44790.0	44790.0	44790.0	44790.0	44790.0	44790.0	44790.0
	Heat Rate (kJ/KWH, LHV)	Engine Shaft	8661.0	8960.7	8996.4	9033.1	9067.8	9104.5	9139.2	8993.0	9024.0	9053.0	9073.0	9103.0
	Efficiency % (LHV basis)	Engine Shaft	41.57	40.98	40.81	40.65	40.49	40.33	40.18	40.03	39.89	39.77	39.68	39.55
Combustion	GT Fuel Flow	kg/hr	10667.0	8214.0	8247.0	8280.0	8312.0	8345.0	8378.0	8408.0	8437.0	8464.0	8484.0	8511.0
	Fuel energy flow (LHV basis)	kW	141816.1	109201.3	109640.2	110081.1	110510.9	110951.2	111382.5	111789.2	112176.1	112531.0	112788.5	113156.1
	Combustor Water Injection Flow	kg/hr	12538.0	7757.0	8008.0	8257.0	8471.0	8578.0	8629.0	8603.0	8480.0	8230.0	7916.0	7047.0
Exhaust Composition	Exhaust Flow	kg/s	161.5	153.8	151.6	149.3	147.0	145.3	143.7	142.0	140.1	138.0	136.3	133.2
	Exhaust Temperature	°C	430.6	348.3	358.9	369.6	380.4	390.3	400.2	410.2	421.2	432.6	442.0	459.1
	Exhaust N_2	mol %	72.334	74.247	74.051	73.821	73.554	73.270	72.930	72.515	72.000	71.370	70.767	69.450
	Exhaust O_2	mol %	13.237	14.882	14.738	14.583	14.418	14.267	14.102	13.918	13.698	13.444	13.216	12.750
	Exhaust CO_2	mol %	3.106	2.542	2.588	2.634	2.681	2.718	2.754	2.790	2.831	2.873	2.906	2.962
	Exhaust Water	mol %	10.456	7.439	7.736	8.077	8.466	8.867	9.340	9.907	10.608	11.457	12.262	14.005
	GT Exhaust Argon	mol %	0.864	0.887	0.885	0.882	0.879	0.876	0.872	0.867	0.860	0.853	0.846	0.830
	GT Neon	mol %	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Nominal Exhaust Emissions	NOx	ppmvd 15 % O_2	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
		mg/m^3 15 % O_2	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4
		kg/hr	22.3	17.1	17.2	17.3	17.4	17.4	17.5	17.6	17.7	17.8	17.8	18.0
	CO	ppmvd 15 % O_2	0.0	103.7	94.5	86.4	79.4	72.9	67.2	62.0	57.3	53.1	50.1	45.6
		mg/Nm^3 15 % O_2	0.0	129.7	118.1	108.0	99.2	91.2	84.0	77.5	71.6	66.3	62.7	57.1
		kg/hr	0.0	43.3	39.6	36.4	33.5	30.9	28.7	26.5	24.6	23.0	21.7	19.9
	UHC (methane equivalent)	ppmvd 15 % O_2	0.0	20.7	18.9	17.3	15.9	14.6	13.4	12.4	11.5	10.6	10.0	9.1
		mg/Nm^3 15 % O_2	0.0	14.9	13.6	12.4	11.4	10.5	9.6	8.9	8.2	7.6	7.2	6.5
	VOC (methane equivalent)	ppmvd 15 % O_2	0.0	4.1	3.8	3.5	3.2	2.9	2.7	2.5	2.3	2.1	2.0	1.8
		mg/Nm^3 15 % O_2	0.0	3.0	2.7	2.5	2.3	2.1	1.9	1.8	1.6	1.5	1.4	1.3
	SOx (SO_2 equivalent)	ppmvd 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		mg/Nm^3 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Excelerate Energy, Lavaca Bay, OG2668

Industrial Trent Mechanical Drive, Wet Low Emissions Combustion system

Based on performance model eTrent v7.3.0

Metric Units	
Loss reference case	**0**
Fuel Temperature °C	**50.0**

Offloading Fuel Constituents

97.19% Methane (CH_4)
.310% Ethane (C_2H_6)
.050% Propane (C_3H_8)
2.44% Nitrogen (N_2)

	Parameters:		Ref	Nominal, Baseload, 3361 rpm, Offloading Fuel										
	Case number		0	23	24	25	26	27	28	29	30	31	32	33
	Load Condition	% Base	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Ambient Conditions	Altitude	m	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
	Barometric Pressure	kPa	101.325	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846
	Ambient Temperature	°C	15.0	-10.0	-5.0	0.0	5.0	10.0	15.0	20.0	25.0	30.0	34.0	41.0
	Ambient Relative Humidity	%	60.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Installation Losses	Inlet Loss	mm H_2O	101.60	107.36	105.68	104.07	102.51	100.98	99.42	97.73	94.93	90.20	86.86	79.25
	Exhaust Loss	mm H_2O	203.20	213.37	210.61	207.96	205.39	202.84	200.17	196.28	186.85	174.36	165.61	149.22
	Auxiliary Electrical Power Offtake	kWe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inlet Air Conditioning	Air Cooling Type		None	None	None	None	None	None	None	None	None	None	None	None
	Cooler Operative?		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Cooler Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Air Temperature	°C	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Relative Humidity	%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Wet Compression Operative?		Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
	Wet Compression Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Engine Inlet Air Flow	kg/s	156.2	167.9	165.0	162.2	159.4	156.7	154.0	151.2	147.6	142.4	138.6	130.3
Performance	Engine Output Shaft Speed	rpm	3400.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0
	Power kW	Engine Shaft	59001.0	59001.0	59001.0	59001.0	59001.0	59001.0	59001.0	58402.0	55064.0	51442.0	48883.0	45131.0
	Heat Rate (kJ/KWH, LHV)	Engine Shaft	8661.0	8631.2	8670.0	8709.8	8749.6	8786.3	8818.9	8684.0	8786.0	8890.0	8972.0	9098.0
	Efficiency % (LHV basis)	Engine Shaft	41.57	42.54	42.35	42.16	41.96	41.79	41.64	41.46	40.97	40.49	40.13	39.57
Combustion	GT Fuel Flow	kg/hr	10667.0	10422.0	10469.0	10517.0	10565.0	10609.0	10649.0	10587.0	10099.0	9547.0	9155.0	8571.0
	Fuel energy flow (LHV basis)	kW	141816.1	138563.3	139188.5	139829.2	140468.4	141052.1	141574.4	140750.1	134267.5	126923.2	121715.9	113952.4
	Combustor Water Injection Flow	kg/hr	12538.0	11043.0	11384.0	11727.0	12029.0	12176.0	12243.0	12058.0	11129.0	9917.0	8939.0	7125.0
Exhaust Composition	Exhaust Flow	kg/s	161.5	172.7	169.9	167.2	164.6	161.9	159.3	156.5	152.4	146.8	142.6	133.7
	Exhaust Temperature	°C	430.6	375.8	387.5	399.2	410.9	423.0	435.2	444.8	444.8	446.5	448.6	460.1
	Exhaust N_2	mol %	72.334	73.549	73.325	73.067	72.774	72.457	72.084	71.688	71.394	70.993	70.556	69.432
	Exhaust O_2	mol %	13.237	14.059	13.886	13.704	13.513	13.315	13.102	12.933	12.994	13.011	12.984	12.726
	Exhaust CO_2	mol %	3.106	2.859	2.915	2.971	3.027	3.083	3.140	3.171	3.101	3.038	2.993	2.971
	Exhaust Water	mol %	10.456	8.652	8.995	9.381	9.813	10.276	10.811	11.349	11.655	12.106	12.621	14.039
	GT Exhaust Argon	mol %	0.864	0.879	0.876	0.873	0.870	0.866	0.861	0.857	0.853	0.848	0.843	0.830
	GT Neon	mol %	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Nominal Exhaust Emissions	NOx	ppmvd 15 % O_2	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
		mg/m^3 15 % O_2	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4
		kg/hr	22.3	21.8	21.9	22.0	22.1	22.2	22.3	22.2	21.2	20.1	19.3	18.1
	CO	ppmvd 15 % O_2	0.0	84.7	77.3	70.7	64.5	59.2	54.3	50.4	48.2	47.3	46.6	45.4
		mg/Nm^3 15 % O_2	0.0	105.9	96.6	88.4	80.7	74.0	67.9	63.0	60.2	59.2	58.3	56.7
		kg/hr	0.0	44.9	41.2	37.8	34.9	32.1	29.4	27.2	24.8	23.1	21.8	19.9
	UHC (methane equivalent)	ppmvd 15 % O_2	0.0	16.9	15.5	14.1	12.9	11.8	10.9	10.1	9.6	9.5	9.3	9.1
		mg/Nm^3 15 % O_2	0.0	12.1	11.1	10.1	9.3	8.5	7.8	7.2	6.9	6.8	6.7	6.5
	VOC (methane equivalent)	ppmvd 15 % O_2	0.0	3.4	3.1	2.8	2.6	2.4	2.2	2.0	1.9	1.9	1.9	1.8
		mg/Nm^3 15 % O_2	0.0	2.4	2.2	2.0	1.9	1.7	1.6	1.4	1.4	1.4	1.3	1.3
	SOx (SO_2 equivalent)	ppmvd 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		mg/Nm^3 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Excelerate Energy, Lavaca Bay, OG2668

Industrial Trent Mechanical Drive, Wet Low Emissions Combustion system

Based on performance model eTrent v7.3.0

Metric Units	
Loss reference case	0
Fuel Temperature °C	50.0

Offloading Fuel Constituents

97.19% Methane (CH_4)
.310% Ethane (C_2H_6)
.050% Propane (C_3H_8)
2.44% Nitrogen (N_2)

	Parameters:		Ref	Nominal, 47617kW, 3361 rpm, Offloading Fuel										
	Case number		0	34	35	36	37	38	39	40	41	42	43	44
	Load Condition	% Base	100.00	80.71	80.71	80.71	80.71	80.71	80.71	81.53	86.48	92.56	97.41	100.00
Ambient Conditions	Altitude	m	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
	Barometric Pressure	kPa	101.325	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846
	Ambient Temperature	°C	15.0	-10.0	-5.0	0.0	5.0	10.0	15.0	20.0	25.0	30.0	34.0	41.0
	Ambient Relative Humidity	%	60.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Installation Losses	Inlet Loss	mm H_2O	101.60	90.16	90.93	90.37	89.13	87.88	86.65	86.30	85.85	85.40	84.99	79.25
	Exhaust Loss	mm H_2O	203.20	172.24	172.91	171.74	169.60	167.42	165.25	164.37	163.33	162.27	161.28	149.22
	Auxiliary Electrical Power Offtake	kWe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inlet Air Conditioning	Air Cooling Type		None	None	None	None	None	None	None	None	None	None	None	None
	Cooler Operative?		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Cooler Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Air Temperature	°C	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Relative Humidity	%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Wet Compression Operative?		Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
	Wet Compression Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Engine Inlet Air Flow	kg/s	156.2	153.9	153.0	151.1	148.7	146.2	143.8	142.1	140.3	138.6	137.1	130.3
Performance	Engine Output Shaft Speed	rpm	3400.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0
	Power kW	Engine Shaft	59001.0	47617.0	47617.0	47617.0	47617.0	47617.0	47617.0	47617.0	47617.0	47617.0	47617.0	45131.0
	Heat Rate (kJ/KWH, LHV)	Engine Shaft	8661.0	8888.3	8934.2	8974.0	9007.6	9037.2	9064.7	8921.0	8954.0	8984.0	9005.0	9098.0
	Efficiency % (LHV basis)	Engine Shaft	41.57	41.31	41.10	40.92	40.76	40.63	40.51	40.35	40.20	40.07	39.98	39.57
Combustion	GT Fuel Flow	kg/hr	10667.0	8661.0	8706.0	8745.0	8778.0	8807.0	8834.0	8868.0	8900.0	8930.0	8951.0	8571.0
	Fuel energy flow (LHV basis)	kW	141816.1	115152.8	115752.3	116265.2	116705.6	117084.1	117446.9	117895.0	118331.0	118727.1	118998.8	113952.4
	Combustor Water Injection Flow	kg/hr	12538.0	8393.0	8706.0	8988.0	9215.0	9309.0	9341.0	9323.0	9205.0	8954.0	8628.0	7125.0
Exhaust Composition	Exhaust Flow	kg/s	161.5	157.5	156.8	155.0	152.6	150.2	147.8	146.2	144.4	142.5	141.0	133.7
	Exhaust Temperature	°C	430.6	355.2	362.9	372.7	383.4	394.5	405.7	415.7	426.3	437.1	446.0	460.1
	Exhaust N_2	mol %	72.334	74.095	73.922	73.697	73.428	73.131	72.775	72.359	71.848	71.224	70.627	69.432
	Exhaust O_2	mol %	13.237	14.695	14.602	14.463	14.295	14.120	13.928	13.744	13.530	13.288	13.067	12.726
	Exhaust CO_2	mol %	3.106	2.615	2.638	2.677	2.725	2.773	2.820	2.857	2.895	2.932	2.962	2.971
	Exhaust Water	mol %	10.456	7.707	7.952	8.279	8.673	9.101	9.604	10.173	10.866	11.703	12.499	14.039
	GT Exhaust Argon	mol %	0.864	0.886	0.883	0.881	0.878	0.874	0.870	0.865	0.859	0.851	0.844	0.830
	GT Neon	mol %	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Nominal Exhaust Emissions	NOx	ppmvd 15 % O_2	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
		mg/m^3 15 % O_2	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4
		kg/hr	22.3	18.1	18.2	18.3	18.3	18.4	18.5	18.6	18.7	18.8	18.8	18.1
	CO	ppmvd 15 % O_2	0.0	98.8	89.9	82.3	75.6	69.6	64.1	59.1	54.6	50.5	47.6	45.4
		mg/Nm^3 15 % O_2	0.0	123.6	112.4	102.9	94.5	87.0	80.2	73.9	68.3	63.2	59.5	56.7
		kg/hr	0.0	43.4	39.8	36.7	33.9	31.2	28.8	26.7	24.8	23.1	21.8	19.9
	UHC (methane equivalent)	ppmvd 15 % O_2	0.0	19.8	18.0	16.5	15.1	13.9	12.8	11.8	10.9	10.1	9.5	9.1
		mg/Nm^3 15 % O_2	0.0	14.2	12.9	11.8	10.8	10.0	9.2	8.5	7.8	7.2	6.8	6.5
	VOC (methane equivalent)	ppmvd 15 % O_2	0.0	4.0	3.6	3.3	3.0	2.8	2.6	2.4	2.2	2.0	1.9	1.8
		mg/Nm^3 15 % O_2	0.0	2.8	2.6	2.4	2.2	2.0	1.8	1.7	1.6	1.4	1.4	1.3
	SOx (SO_2 equivalent)	ppmvd 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		mg/Nm^3 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Excelerate Energy, Lavaca Bay, OG2668

Industrial Trent Mechanical Drive, Wet Low Emissions Combustion system

Based on performance model eTrent v7.3.0

Metric Units	
Loss reference case	0
Fuel Temperature °C	50.0

No Offload Fuel Constituents

95.578% Methane (CH4)
2.146% Ethane (C2H6)
0.397% Propane (C3H8)
0.021% i-Butane (C4H10i)
0.018% n-Butane (C4H10n)
0.007% i-Pentane (C5H12i)
0.005% n-Pentane (C5H12n)
1.809% Nitrogen (N2)

	Parameters:		Ref	Guarantee	Nominal, Baseload, 3307 rpm, No Offload Fuel										
	Case number		0	54	45	46	47	48	49	50	51	52	53	54	55
	Load Condition	% Base	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Ambient Conditions	Altitude	m	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
	Barometric Pressure	kPa	101.325	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846
	Ambient Temperature	°C	15.0	34.0	-10.0	-5.0	0.0	5.0	10.0	15.0	20.0	25.0	30.0	34.0	41.0
	Ambient Relative Humidity	%	60.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Installation Losses	Inlet Loss	mm H_2O	101.60	85.56	104.77	103.14	101.56	100.04	98.49	96.99	95.25	93.16	89.11	85.56	79.15
	Exhaust Loss	mm H_2O	203.20	163.92	209.88	207.20	204.63	202.14	199.50	196.94	191.77	185.02	172.87	163.92	149.03
	Auxiliary Electrical Power Offtake	kWe	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inlet Air Conditioning	Air Cooling Type		None	None	None	None	None	None	None	None	None	None	None	None	None
	Cooler Operative?		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Cooler Water Flow	kg/hr	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Air Temperature	°C	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Relative Humidity	%	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Wet Compression Operative?		Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
	Wet Compression Water Flow	kg/hr	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Engine Inlet Air Flow	kg/s	156.2		165.9	163.0	160.2	157.5	154.8	152.1	149.3	146.2	141.5	137.5	130.2
Performance	Engine Output Shaft Speed	rpm	3400.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0
	Power kW	Engine Shaft	59001.0	47217.0	59001.0	59001.0	59001.0	59001.0	59001.0	59001.0	57729.0	55637.0	51470.0	48980.0	45135.0
	Heat Rate (kJ/KWH, LHV)	Engine Shaft	8661.0	9235.0	8634.3	8675.1	8716.9	8757.7	8791.4	8826.1	8696.0	8761.0	8889.0	8966.0	9098.0
	Efficiency % (LHV basis)	Engine Shaft	41.57	38.98	42.53	42.33	42.13	41.93	41.77	41.60	41.40	41.09	40.50	40.15	39.57
Combustion	GT Fuel Flow	kg/hr	10667.0		10331.0	10379.0	10429.0	10479.0	10519.0	10560.0	10384.0	10082.0	9464.0	9084.0	8493.0
	Fuel energy flow (LHV basis)	kW	141816.1		138612.9	139263.9	139931.8	140598.1	141139.9	141691.9	139325.7	135283.6	126981.0	121881.6	113957.9
	Combustor Water Injection Flow	kg/hr	12538.0		11133.0	11478.0	11825.0	12133.0	12276.0	12352.0	11969.0	11298.0	10017.0	9039.0	7212.0
Exhaust Composition	Exhaust Flow	kg/s	161.5		170.7	167.9	165.2	162.7	160.0	157.4	154.5	151.1	145.9	141.6	133.7
	Exhaust Temperature	°C	430.6		380.0	391.9	403.7	415.6	427.7	440.0	446.3	450.0	448.6	451.4	460.0
	Exhaust N_2	mol %	72.334		73.491	73.264	73.004	72.708	72.390	72.014	71.680	71.312	70.956	70.512	69.419
	Exhaust O_2	mol %	13.237		13.984	13.809	13.624	13.430	13.231	13.015	12.923	12.882	12.973	12.931	12.728
	Exhaust CO_2	mol %	3.106		2.910	2.968	3.025	3.083	3.140	3.198	3.199	3.169	3.075	3.037	2.991
	Exhaust Water	mol %	10.456		8.733	9.081	9.472	9.907	10.372	10.910	11.339	11.782	12.145	12.675	14.030
	GT Exhaust Argon	mol %	0.864		0.878	0.876	0.873	0.869	0.865	0.861	0.857	0.852	0.848	0.843	0.830
	GT Neon	mol %	0.003		0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Nominal Exhaust Emissions	NOx	ppmvd 15 % O_2	25.0		25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
		mg/m^3 15 % O_2	51.4		51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4
		kg/hr	22.3		21.8	21.9	22.0	22.1	22.2	22.3	22.0	21.3	20.1	19.3	18.1
	CO	ppmvd 15 % O_2	0.0		84.7	77.3	70.6	64.5	59.1	54.0	50.8	48.3	47.2	46.5	45.4
		mg/Nm^3 15 % O_2	0.0		105.9	96.6	88.2	80.7	73.9	67.6	63.5	60.4	59.0	58.1	56.7
		kg/hr	0.0		44.8	41.2	37.8	34.7	31.9	29.4	27.2	25.1	23.1	21.8	19.9
	UHC (methane equivalent)	ppmvd 15 % O_2	0.0		16.9	15.5	14.1	12.9	11.8	10.8	10.2	9.7	9.4	9.3	9.1
		mg/Nm^3 15 % O_2	0.0		12.1	11.1	10.1	9.3	8.5	7.7	7.3	6.9	6.8	6.7	6.5
	VOC (methane equivalent)	ppmvd 15 % O_2	0.0		3.4	3.1	2.8	2.6	2.4	2.2	2.0	1.9	1.9	1.9	1.8
		mg/Nm^3 15 % O_2	0.0		2.4	2.2	2.0	1.9	1.7	1.5	1.5	1.4	1.4	1.3	1.3
	SOx (SO_2 equivalent)	ppmvd 15 % O_2	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		mg/Nm^3 15 % O_2	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		kg/hr	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Excelerate Energy, Lavaca Bay, OG2668

Industrial Trent Mechanical Drive, Wet Low Emissions Combustion system

Based on performance model eTrent v7.3.0

Metric Units	
Loss reference case	0
Fuel Temperature °C	50.0

No Offload Fuel Constituents

95.578% Methane (CH4)
2.146% Ethane (C2H6)
0.397% Propane (C3H8)
0.021% i-Butane (C4H10i)
0.018% n-Butane (C4H10n)
0.007% i-Pentane (C5H12i)
0.005% n-Pentane (C5H12n)
1.809% Nitrogen (N2)

	Parameters:		Ref	Nominal, 44790kW, 3307 rpm, No Offload Fuel										
	Case number		0	56	57	58	59	60	61	62	63	64	65	66
	Load Condition	% Base	100.00	75.91	75.91	75.91	75.91	75.91	75.91	77.59	80.50	87.02	91.45	99.24
Ambient Conditions	Altitude	m	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
	Barometric Pressure	kPa	101.325	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846
	Ambient Temperature	°C	15.0	-10.0	-5.0	0.0	5.0	10.0	15.0	20.0	25.0	30.0	34.0	41.0
	Ambient Relative Humidity	%	60.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Installation Losses	Inlet Loss	mm H_2O	101.60	86.22	85.14	84.02	82.90	82.47	82.10	81.72	81.01	80.24	79.66	78.68
	Exhaust Loss	mm H_2O	203.20	162.57	160.68	158.76	156.84	155.87	154.99	154.06	152.69	151.21	150.05	147.95
	Auxiliary Electrical Power Offtake	kWe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inlet Air Conditioning	Air Cooling Type		None	None	None	None	None	None	None	None	None	None	None	None
	Cooler Operative?		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Cooler Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Air Temperature	°C	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Relative Humidity	%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Wet Compression Operative?		Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
	Wet Compression Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Engine Inlet Air Flow	kg/s	156.2	150.5	148.1	145.7	143.4	141.6	140.0	138.3	136.3	134.3	132.7	129.8
Performance	Engine Output Shaft Speed	rpm	3400.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0
	Power kW	Engine Shaft	59001.0	44790.0	44790.0	44790.0	44790.0	44790.0	44790.0	44790.0	44790.0	44790.0	44790.0	44790.0
	Heat Rate (kJ/KWH, LHV)	Engine Shaft	8661.0	8966.8	9003.5	9039.2	9074.9	9110.6	9146.3	9000.0	9031.0	9059.0	9080.0	9109.0
	Efficiency % (LHV basis)	Engine Shaft	41.57	40.95	40.79	40.62	40.46	40.30	40.15	40.00	39.86	39.74	39.65	39.52
Combustion	GT Fuel Flow	kg/hr	10667.0	8145.0	8177.0	8210.0	8242.0	8275.0	8307.0	8338.0	8366.0	8393.0	8412.0	8439.0
	Fuel energy flow (LHV basis)	kW	141816.1	109280.7	109720.3	110161.7	110591.9	111032.6	111464.1	111871.3	112257.7	112612.6	112869.5	113235.7
	Combustor Water Injection Flow	kg/hr	12538.0	7857.0	8108.0	8357.0	8572.0	8679.0	8729.0	8704.0	8579.0	8327.0	8012.0	7139.0
Exhaust Composition	Exhaust Flow	kg/s	161.5	153.8	151.6	149.3	147.0	145.3	143.7	142.0	140.1	138.0	136.3	133.2
	Exhaust Temperature	°C	430.6	348.4	359.0	369.7	380.4	390.4	400.2	410.3	421.3	432.7	442.1	459.2
	Exhaust N_2	mol %	72.334	74.234	74.037	73.807	73.540	73.256	72.915	72.500	71.986	71.356	70.753	69.437
	Exhaust O_2	mol %	13.237	14.883	14.739	14.584	14.419	14.267	14.103	13.919	13.698	13.445	13.217	12.751
	Exhaust CO_2	mol %	3.106	2.559	2.605	2.652	2.699	2.736	2.773	2.809	2.850	2.893	2.925	2.982
	Exhaust Water	mol %	10.456	7.434	7.731	8.073	8.461	8.862	9.335	9.902	10.602	11.451	12.256	13.998
	GT Exhaust Argon	mol %	0.864	0.887	0.885	0.882	0.879	0.876	0.872	0.867	0.861	0.853	0.846	0.830
	GT Neon	mol %	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Nominal Exhaust Emissions	NOx	ppmvd 15 % O_2	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
		mg/m^3 15 % O_2	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4
		kg/hr	22.3	17.1	17.2	17.3	17.4	17.4	17.5	17.6	17.7	17.8	17.8	18.0
	CO	ppmvd 15 % O_2	0.0	103.3	94.1	86.2	79.4	72.9	67.2	62.0	57.3	53.1	50.1	45.6
		mg/Nm^3 15 % O_2	0.0	129.2	117.6	107.8	99.2	91.2	84.0	77.5	71.6	66.3	62.7	57.1
		kg/hr	0.0	43.1	39.5	36.4	33.5	30.9	28.7	26.5	24.6	23.0	21.7	19.9
	UHC (methane equivalent)	ppmvd 15 % O_2	0.0	20.7	18.8	17.2	15.9	14.6	13.4	12.4	11.5	10.6	10.0	9.1
		mg/Nm^3 15 % O_2	0.0	14.8	13.5	12.4	11.4	10.5	9.6	8.9	8.2	7.6	7.2	6.5
	VOC (methane equivalent)	ppmvd 15 % O_2	0.0	4.1	3.8	3.4	3.2	2.9	2.7	2.5	2.3	2.1	2.0	1.8
		mg/Nm^3 15 % O_2	0.0	3.0	2.7	2.5	2.3	2.1	1.9	1.8	1.6	1.5	1.4	1.3
	SOx (SO_2 equivalent)	ppmvd 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		mg/Nm^3 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Excelerate Energy, Lavaca Bay, OG2668

Industrial Trent Mechanical Drive, Wet Low Emissions Combustion system

Based on performance model eTrent v7.3.0

Metric Units	
Loss reference case	0
Fuel Temperature °C	50.0

No Offload Fuel Constituents

95.578% Methane (CH4)
2.146% Ethane (C2H6)
0.397% Propane (C3H8)
0.021% i-Butane (C4H10i)
0.018% n-Butane (C4H10n)
0.007% i-Pentane (C5H12i)
0.005% n-Pentane (C5H12n)
1.809% Nitrogen (N2)

	Parameters:		Ref	Nominal, Baseload, 3361 rpm, No Offload Fuel										
	Case number		0	67	68	69	70	71	72	73	74	75	76	77
	Load Condition	% Base	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Ambient Conditions	Altitude	m	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
	Barometric Pressure	kPa	101.325	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846
	Ambient Temperature	°C	15.0	-10.0	-5.0	0.0	5.0	10.0	15.0	20.0	25.0	30.0	34.0	41.0
	Ambient Relative Humidity	%	60.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Installation Losses	Inlet Loss	mm H_2O	101.60	107.36	105.68	104.07	102.51	100.98	99.41	97.73	94.93	90.20	86.85	79.24
	Exhaust Loss	mm H_2O	203.20	213.41	210.65	207.99	205.42	202.88	200.21	196.31	186.89	174.40	165.64	149.24
	Auxiliary Electrical Power Offtake	kWe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inlet Air Conditioning	Air Cooling Type		None	None	None	None	None	None	None	None	None	None	None	None
	Cooler Operative?		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Cooler Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Air Temperature	°C	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Relative Humidity	%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Wet Compression Operative?		Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
	Wet Compression Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Engine Inlet Air Flow	kg/s	156.2	167.9	165.0	162.2	159.4	156.7	154.0	151.2	147.6	142.4	138.5	130.3
Performance	Engine Output Shaft Speed	rpm	3400.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0
	Power kW	Engine Shaft	59001.0	59001.0	59001.0	59001.0	59001.0	59001.0	59001.0	58399.0	55065.0	51447.0	48887.0	45133.0
	Heat Rate (kJ/KWH, LHV)	Engine Shaft	8661.0	8637.4	8677.1	8716.9	8756.7	8792.4	8825.0	8690.0	8792.0	8896.0	8978.0	9104.0
	Efficiency % (LHV basis)	Engine Shaft	41.57	42.51	42.32	42.13	41.93	41.76	41.61	41.43	40.94	40.46	40.10	39.54
Combustion	GT Fuel Flow	kg/hr	10667.0	10334.0	10381.0	10429.0	10477.0	10520.0	10559.0	10497.0	10014.0	9467.0	9078.0	8499.0
	Fuel energy flow (LHV basis)	kW	141816.1	138664.3	139290.2	139931.5	140571.3	141155.9	141678.1	140845.3	134367.8	127023.9	121811.2	114036.9
	Combustor Water Injection Flow	kg/hr	12538.0	11170.0	11511.0	11854.0	12158.0	12304.0	12370.0	12182.0	11248.0	10028.0	9044.0	7218.0
Exhaust Composition	Exhaust Flow	kg/s	161.5	172.7	169.9	167.2	164.6	162.0	159.3	156.5	152.4	146.8	142.6	133.7
	Exhaust Temperature	°C	430.6	375.9	387.6	399.2	411.0	423.1	435.2	444.9	444.9	446.7	448.8	460.2
	Exhaust N_2	mol %	72.334	73.534	73.310	73.052	72.759	72.441	72.068	71.673	71.378	70.978	70.542	69.418
	Exhaust O_2	mol %	13.237	14.060	13.887	13.705	13.514	13.316	13.103	12.934	12.995	13.012	12.985	12.727
	Exhaust CO_2	mol %	3.106	2.878	2.935	2.991	3.047	3.104	3.161	3.192	3.122	3.059	3.014	2.991
	Exhaust Water	mol %	10.456	8.647	8.990	9.376	9.807	10.270	10.805	11.342	11.649	12.100	12.614	14.031
	GT Exhaust Argon	mol %	0.864	0.879	0.876	0.873	0.870	0.866	0.861	0.857	0.853	0.848	0.843	0.830
	GT Neon	mol %	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Nominal Exhaust Emissions	NOx	ppmvd 15 % O_2	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
		mg/m³ 15 % O_2	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4
		kg/hr	22.3	21.8	21.9	22.0	22.1	22.2	22.3	22.2	21.2	20.1	19.3	18.1
	CO	ppmvd 15 % O_2	0.0	84.7	77.3	70.7	64.5	59.2	54.3	50.4	48.2	47.3	46.6	45.4
		mg/Nm³ 15 % O_2	0.0	105.9	96.6	88.4	80.7	74.0	67.9	63.0	60.2	59.2	58.3	56.7
		kg/hr	0.0	44.9	41.2	37.8	34.9	32.1	29.4	27.2	24.8	23.1	21.8	19.9
	UHC (methane equivalent)	ppmvd 15 % O_2	0.0	16.9	15.5	14.1	12.9	11.8	10.9	10.1	9.6	9.5	9.3	9.1
		mg/Nm³ 15 % O_2	0.0	12.1	11.1	10.1	9.3	8.5	7.8	7.2	6.9	6.8	6.7	6.5
	VOC (methane equivalent)	ppmvd 15 % O_2	0.0	3.4	3.1	2.8	2.6	2.4	2.2	2.0	1.9	1.9	1.9	1.8
		mg/Nm³ 15 % O_2	0.0	2.4	2.2	2.0	1.9	1.7	1.6	1.4	1.4	1.4	1.3	1.3
	SOx (SO_2 equivalent)	ppmvd 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		mg/Nm³ 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Excelerate Energy, Lavaca Bay, OG2668

Industrial Trent Mechanical Drive, Wet Low Emissions Combustion system

Based on performance model eTrent v7.3.0

Metric Units	
Loss reference case	0
Fuel Temperature °C	50.0

No Offload Fuel Constituents

95.578% Methane (CH4)
2.146% Ethane (C2H6)
0.397% Propane (C3H8)
0.021% i-Butane (C4H10i)
0.018% n-Butane (C4H10n)
0.007% i-Pentane (C5H12i)
0.005% n-Pentane (C5H12n)
1.809% Nitrogen (N2)

	Parameters:		Ref	Nominal, 47617kW, 3361 rpm, No Offload Fuel										
	Case number		0	78	79	80	81	82	83	84	85	86	87	88
	Load Condition	% Base	100.00	80.71	80.71	80.71	80.71	80.71	80.71	81.54	86.47	92.56	97.40	100.00
Ambient Conditions	Altitude	m	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
	Barometric Pressure	kPa	101.325	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846
	Ambient Temperature	°C	15.0	-10.0	-5.0	0.0	5.0	10.0	15.0	20.0	25.0	30.0	34.0	41.0
	Ambient Relative Humidity	%	60.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Installation Losses	Inlet Loss	mm H_2O	101.60	90.15	90.92	90.36	89.12	87.87	86.64	86.29	85.84	85.39	84.98	79.24
	Exhaust Loss	mm H_2O	203.20	172.26	172.93	171.75	169.61	167.44	165.27	164.39	163.35	162.28	161.30	149.24
	Auxiliary Electrical Power Offtake	kWe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inlet Air Conditioning	Air Cooling Type		None	None	None	None	None	None	None	None	None	None	None	None
	Cooler Operative?		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Cooler Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Air Temperature	°C	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Relative Humidity	%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Wet Compression Operative?		Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
	Wet Compression Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Engine Inlet Air Flow	kg/s	156.2	153.9	153.0	151.1	148.6	146.2	143.8	142.1	140.3	138.5	137.0	130.3
Performance	Engine Output Shaft Speed	rpm	3400.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0
	Power kW	Engine Shaft	59001.0	47617.0	47617.0	47617.0	47617.0	47617.0	47617.0	47617.0	47617.0	47617.0	47617.0	45133.0
	Heat Rate (kJ/KWH, LHV)	Engine Shaft	8661.0	8894.4	8940.3	8980.1	9014.8	9043.3	9071.9	8928.0	8961.0	8991.0	9011.0	9104.0
	Efficiency % (LHV basis)	Engine Shaft	41.57	41.28	41.07	40.89	40.73	40.60	40.48	40.32	40.17	40.04	39.95	39.54
Combustion	GT Fuel Flow	kg/hr	10667.0	8588.0	8633.0	8671.0	8704.0	8733.0	8760.0	8793.0	8825.0	8855.0	8875.0	8499.0
	Fuel energy flow (LHV basis)	kW	141816.1	115236.7	115837.3	116350.7	116791.4	117170.3	117533.2	117981.3	118417.1	118812.6	119083.9	114036.9
	Combustor Water Injection Flow	kg/hr	12538.0	8498.0	8812.0	9094.0	9322.0	9415.0	9447.0	9429.0	9310.0	9057.0	8730.0	7218.0
Exhaust Composition	Exhaust Flow	kg/s	161.5	157.5	156.8	155.0	152.6	150.2	147.8	146.2	144.4	142.5	141.0	133.7
	Exhaust Temperature	°C	430.6	355.3	363.0	372.7	383.5	394.6	405.8	415.8	426.4	437.2	446.1	460.2
	Exhaust N_2	mol %	72.334	74.081	73.908	73.683	73.413	73.116	72.761	72.345	71.834	71.210	70.612	69.418
	Exhaust O_2	mol %	13.237	14.695	14.602	14.463	14.295	14.120	13.929	13.744	13.531	13.288	13.067	12.727
	Exhaust CO_2	mol %	3.106	2.633	2.656	2.695	2.743	2.791	2.839	2.876	2.914	2.952	2.982	2.991
	Exhaust Water	mol %	10.456	7.703	7.948	8.275	8.668	9.096	9.599	10.168	10.861	11.696	12.492	14.031
	GT Exhaust Argon	mol %	0.864	0.886	0.884	0.881	0.878	0.874	0.870	0.865	0.859	0.851	0.844	0.830
	GT Neon	mol %	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Nominal Exhaust Emissions	NOx	ppmvd 15 % O_2	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
		mg/m³ 15 % O_2	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4
		kg/hr	22.3	18.1	18.2	18.3	18.3	18.4	18.5	18.6	18.7	18.8	18.8	18.1
	CO	ppmvd 15 % O_2	0.0	98.6	89.9	82.3	75.6	69.6	64.1	59.1	54.6	50.5	47.6	45.4
		mg/Nm³ 15 % O_2	0.0	123.2	112.4	102.9	94.5	87.0	80.2	73.9	68.3	63.2	59.5	56.7
		kg/hr	0.0	43.4	39.8	36.7	33.9	31.2	28.8	26.7	24.8	23.1	21.8	19.9
	UHC (methane equivalent)	ppmvd 15 % O_2	0.0	19.7	18.0	16.5	15.1	13.9	12.8	11.8	10.9	10.1	9.5	9.1
		mg/Nm³ 15 % O_2	0.0	14.1	12.9	11.8	10.8	10.0	9.2	8.5	7.8	7.2	6.8	6.5
	VOC (methane equivalent)	ppmvd 15 % O_2	0.0	3.9	3.6	3.3	3.0	2.8	2.6	2.4	2.2	2.0	1.9	1.8
		mg/Nm³ 15 % O_2	0.0	2.8	2.6	2.4	2.2	2.0	1.8	1.7	1.6	1.4	1.4	1.3
	SOx (SO_2 equivalent)	ppmvd 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		mg/Nm³ 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Excelerate Energy, Lavaca Bay, OG2668

Industrial Trent Mechanical Drive, Wet Low Emissions Combustion system

Based on performance model eTrent v7.3.0

Metric Units	
Loss reference case	0
Fuel Temperature °C	50.0

Lean Hi Fuel Constituents

97.19% Methane (CH4)
.310% Ethane (C2H6)
.050% Propane (C3H8)
2.44% Nitrogen (N2)

	Parameters:		Ref	Nominal, Baseload, 3307 rpm, Lean Hi Fue										
	Case number		0	90	91	92	93	94	95	96	97	98	99	100
	Load Condition	% Base	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Ambient Conditions	Altitude	m	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
	Barometric Pressure	kPa	101.325	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846
	Ambient Temperature	°C	15.0	-10.0	-5.0	0.0	5.0	10.0	15.0	20.0	25.0	30.0	34.0	41.0
	Ambient Relative Humidity	%	60.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Installation Losses	Inlet Loss	mm H_2O	101.60	104.78	103.14	101.56	100.04	98.49	96.99	95.28	93.22	89.11	85.56	79.15
	Exhaust Loss	mm H_2O	203.20	209.83	207.15	204.58	202.09	199.45	196.89	191.88	185.20	172.77	163.82	148.95
	Auxiliary Electrical Power Offtake	kWe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inlet Air Conditioning	Air Cooling Type		None	None	None	None	None	None	None	None	None	None	None	None
	Cooler Operative?		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Cooler Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Air Temperature	°C	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Relative Humidity	%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Wet Compression Operative?		Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
	Wet Compression Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Engine Inlet Air Flow	kg/s	156.2	165.9	163.0	160.2	157.5	154.8	152.1	149.3	146.3	141.5	137.5	130.2
Performance	Engine Output Shaft Speed	rpm	3400.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0
	Power kW	Engine Shaft	59001.0	59001.0	59001.0	59001.0	59001.0	59001.0	59001.0	57805.0	55744.0	51440.0	48951.0	45110.0
	Heat Rate (kJ/KWH, LHV)	Engine Shaft	8661.0	8610.8	8650.6	8692.4	8733.2	8766.9	8801.6	8671.0	8734.0	8865.0	8942.0	9073.0
	Efficiency % (LHV basis)	Engine Shaft	41.57	42.64	42.45	42.24	42.04	41.88	41.72	41.52	41.22	40.61	40.26	39.68
Combustion	GT Fuel Flow	kg/hr	10667.0	11223.0	11275.0	11329.0	11383.0	11427.0	11472.0	11294.0	10970.0	10275.0	9863.0	9223.0
	Fuel energy flow (LHV basis)	kW	141816.1	138228.9	138876.4	139540.5	140203.2	140746.1	141296.1	139103.5	135117.7	126558.8	121479.3	113593.6
	Combustor Water Injection Flow	kg/hr	12538.0	10701.0	11044.0	11389.0	11694.0	11837.0	11914.0	11562.0	10910.0	9631.0	8676.0	6887.0
Exhaust Composition	Exhaust Flow	kg/s	161.5	170.8	168.0	165.4	162.8	160.1	157.6	154.6	151.3	146.1	141.7	133.8
	Exhaust Temperature	°C	430.6	379.4	391.3	403.1	415.0	427.1	439.3	445.9	449.6	447.7	450.6	459.1
	Exhaust N_2	mol %	72.334	73.601	73.377	73.119	72.826	72.509	72.135	71.795	71.424	71.073	70.626	69.529
	Exhaust O_2	mol %	13.237	13.986	13.811	13.627	13.433	13.234	13.018	12.918	12.876	12.980	12.937	12.732
	Exhaust CO_2	mol %	3.106	2.881	2.938	2.995	3.052	3.108	3.165	3.169	3.141	3.043	3.004	2.959
	Exhaust Water	mol %	10.456	8.651	8.996	9.385	9.819	10.282	10.819	11.259	11.704	12.055	12.588	13.948
	GT Exhaust Argon	mol %	0.864	0.878	0.875	0.872	0.869	0.865	0.860	0.856	0.852	0.848	0.842	0.829
	GT Neon	mol %	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Nominal Exhaust Emissions	NOx	ppmvd 15 % O_2	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
		mg/Nm^3 15 % O_2	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4
		kg/hr	22.3	21.8	21.9	22.1	22.2	22.3	22.4	22.1	21.4	20.1	19.3	18.1
	CO	ppmvd 15 % O_2	0.0	84.4	77.1	70.6	64.4	58.9	54.0	50.8	48.2	46.9	46.2	45.2
		mg/Nm^3 15 % O_2	0.0	105.5	96.4	88.2	80.5	73.7	67.6	63.5	60.2	58.6	57.8	56.5
		kg/hr	0.0	44.8	41.2	37.8	34.7	32.1	29.4	27.3	25.2	23.0	21.8	19.9
	UHC (methane equivalent)	ppmvd 15 % O_2	0.0	16.9	15.4	14.1	12.9	11.8	10.8	10.2	9.6	9.4	9.2	9.0
		mg/Nm^3 15 % O_2	0.0	12.1	11.1	10.1	9.2	8.5	7.7	7.3	6.9	6.7	6.6	6.5
	VOC (methane equivalent)	ppmvd 15 % O_2	0.0	3.4	3.1	2.8	2.6	2.4	2.2	2.0	1.9	1.9	1.8	1.8
		mg/Nm^3 15 % O_2	0.0	2.4	2.2	2.0	1.8	1.7	1.5	1.5	1.4	1.3	1.3	1.3
	SOx (SO_2 equivalent)	ppmvd 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		mg/Nm^3 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Excelerate Energy, Lavaca Bay, OG2668

Industrial Trent Mechanical Drive, Wet Low Emissions Combustion system

Based on performance model eTrent v7.3.0

Metric Units	
Loss reference case	**0**
Fuel Temperature °C	**50.0**

Lean Hi Fuel Constituents

97.19% Methane (CH4)
.310% Ethane (C2H6)
.050% Propane (C3H8)
2.44% Nitrogen (N2)

	Parameters:		Ref	Nominal, 44790kW, 3307 rpm, Lean Hi Fuel										
	Case number		0	101	102	103	104	105	106	107	108	109	110	111
	Load Condition	% Base	100.00	75.91	75.91	75.91	75.91	75.91	75.91	77.48	80.35	87.07	91.50	99.29
Ambient Conditions	Altitude	m	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
	Barometric Pressure	kPa	101.325	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846
	Ambient Temperature	°C	15.0	-10.0	-5.0	0.0	5.0	10.0	15.0	20.0	25.0	30.0	34.0	41.0
	Ambient Relative Humidity	%	60.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Installation Losses	Inlet Loss	mm H_2O	101.60	86.24	85.16	84.05	82.93	82.49	82.13	81.74	81.03	80.26	79.69	78.71
	Exhaust Loss	mm H_2O	203.20	162.56	160.68	158.76	156.84	155.86	154.98	154.05	152.68	151.20	150.04	147.94
	Auxiliary Electrical Power Offtake	kWe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inlet Air Conditioning	Air Cooling Type		None	None	None	None	None	None	None	None	None	None	None	None
	Cooler Operative?		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Cooler Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Air Temperature	°C	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Relative Humidity	%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Wet Compression Operative?		Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
	Wet Compression Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Engine Inlet Air Flow	kg/s	156.2	150.5	148.1	145.7	143.4	141.7	140.0	138.3	136.4	134.3	132.7	129.8
Performance	Engine Output Shaft Speed	rpm	3400.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0	3307.0
	Power kW	Engine Shaft	59001.0	44790.0	44790.0	44790.0	44790.0	44790.0	44790.0	44790.0	44790.0	44790.0	44790.0	44789.0
	Heat Rate (kJ/KWH, LHV)	Engine Shaft	8661.0	8942.3	8978.0	9014.8	9049.4	9085.1	9120.8	8974.0	9006.0	9034.0	9055.0	9085.0
	Efficiency % (LHV basis)	Engine Shaft	41.57	41.06	40.90	40.73	40.58	40.42	40.26	40.11	39.97	39.85	39.76	39.63
Combustion	GT Fuel Flow	kg/hr	10667.0	8848.0	8884.0	8919.0	8954.0	8990.0	9024.0	9057.0	9089.0	9117.0	9138.0	9168.0
	Fuel energy flow (LHV basis)	kW	141816.1	108982.0	109418.6	109857.2	110284.4	110723.0	111152.8	111558.1	111944.2	112298.2	112556.1	112924.5
	Combustor Water Injection Flow	kg/hr	12538.0	7518.0	7767.0	8015.0	8228.0	8334.0	8386.0	8361.0	8239.0	7992.0	7682.0	6821.0
Exhaust Composition	Exhaust Flow	kg/s	161.5	154.0	151.7	149.4	147.1	145.5	143.8	142.2	140.2	138.1	136.4	133.4
	Exhaust Temperature	°C	430.6	347.9	358.5	369.2	379.9	389.8	399.7	409.7	420.6	432.0	441.3	458.4
	Exhaust N_2	mol %	72.334	74.330	74.136	73.907	73.643	73.360	73.020	72.607	72.093	71.464	70.862	69.545
	Exhaust O_2	mol %	13.237	14.885	14.741	14.586	14.421	14.270	14.106	13.922	13.701	13.448	13.221	12.754
	Exhaust CO_2	mol %	3.106	2.533	2.578	2.625	2.671	2.708	2.744	2.780	2.821	2.863	2.895	2.951
	Exhaust Water	mol %	10.456	7.362	7.658	7.997	8.384	8.784	9.256	9.822	10.522	11.370	12.175	13.918
	GT Exhaust Argon	mol %	0.864	0.887	0.885	0.882	0.879	0.875	0.871	0.866	0.860	0.852	0.845	0.829
	GT Neon	mol %	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Nominal Exhaust Emissions	NOx	ppmvd 15 % O_2	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
		mg/m^3 15 % O_2	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4
		kg/hr	22.3	17.2	17.3	17.3	17.4	17.5	17.6	17.7	17.7	17.8	17.9	18.0
	CO	ppmvd 15 % O_2	0.0	105.7	96.2	87.6	80.2	73.5	67.5	62.3	57.5	53.2	50.3	45.6
		mg/Nm^3 15 % O_2	0.0	132.1	120.2	109.6	100.3	91.9	84.4	77.9	71.9	66.5	62.8	57.1
		kg/hr	0.0	44.2	40.5	37.0	34.0	31.4	29.0	26.7	24.8	23.1	21.8	20.0
	UHC (methane equivalent)	ppmvd 15 % O_2	0.0	21.1	19.2	17.5	16.0	14.7	13.5	12.5	11.5	10.6	10.1	9.1
		mg/Nm^3 15 % O_2	0.0	15.2	13.8	12.6	11.5	10.5	9.7	8.9	8.3	7.6	7.2	6.5
	VOC (methane equivalent)	ppmvd 15 % O_2	0.0	4.2	3.8	3.5	3.2	2.9	2.7	2.5	2.3	2.1	2.0	1.8
		mg/Nm^3 15 % O_2	0.0	3.0	2.8	2.5	2.3	2.1	1.9	1.8	1.7	1.5	1.4	1.3
	SOx (SO_2 equivalent)	ppmvd 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		mg/Nm^3 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Excelerate Energy, Lavaca Bay, OG2668

Industrial Trent Mechanical Drive, Wet Low Emissions Combustion system

Based on performance model eTrent v7.3.0

Metric Units	
Loss reference case	0
Fuel Temperature °C	50.0

Lean Hi Fuel Constituents

97.19% Methane (CH4)
.310% Ethane (C2H6)
.050% Propane (C3H8)
2.44% Nitrogen (N2)

	Parameters:		Ref	Nominal, Baseload, 3361 rpm, Lean Hi Fuel										
	Case number		0	112	113	114	115	116	117	118	119	120	121	122
	Load Condition	% Base	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Ambient Conditions	Altitude	m	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
	Barometric Pressure	kPa	101.325	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846
	Ambient Temperature	°C	15.0	-10.0	-5.0	0.0	5.0	10.0	15.0	20.0	25.0	30.0	34.0	41.0
	Ambient Relative Humidity	%	60.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Installation Losses	Inlet Loss	mm H_2O	101.60	107.36	105.69	104.07	102.51	100.98	99.42	97.75	94.93	90.19	86.85	79.23
	Exhaust Loss	mm H_2O	203.20	213.36	210.60	207.94	205.37	202.83	200.15	196.41	186.78	174.29	165.54	149.16
	Auxiliary Electrical Power Offtake	kWe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inlet Air Conditioning	Air Cooling Type		None	None	None	None	None	None	None	None	None	None	None	None
	Cooler Operative?		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Cooler Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Air Temperature	°C	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Relative Humidity	%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Wet Compression Operative?		Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
	Wet Compression Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Engine Inlet Air Flow	kg/s	156.2	167.9	165.0	162.2	159.4	156.7	154.0	151.3	147.6	142.4	138.5	130.3
Performance	Engine Output Shaft Speed	rpm	3400.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0
	Power kW	Engine Shaft	59001.0	59001.0	59001.0	59001.0	59001.0	59001.0	59001.0	58478.0	55034.0	51416.0	48857.0	45110.0
	Heat Rate (kJ/KWH, LHV)	Engine Shaft	8661.0	8613.9	8652.7	8692.4	8732.2	8767.9	8800.6	8665.0	8768.0	8872.0	8954.0	9080.0
	Efficiency % (LHV basis)	Engine Shaft	41.57	42.63	42.44	42.24	42.05	41.88	41.72	41.55	41.06	40.58	40.21	39.65
Combustion	GT Fuel Flow	kg/hr	10667.0	11227.0	11277.0	11329.0	11381.0	11428.0	11470.0	11417.0	10873.0	10279.0	9857.0	9229.0
	Fuel energy flow (LHV basis)	kW	141816.1	138280.0	138902.4	139540.0	140176.2	140757.7	141278.3	140621.1	133922.6	126602.2	121410.3	113676.4
	Combustor Water Injection Flow	kg/hr	12538.0	10738.0	11077.0	11417.0	11718.0	11864.0	11932.0	11770.0	10832.0	9642.0	8680.0	6893.0
Exhaust Composition	Exhaust Flow	kg/s	161.5	172.8	170.0	167.3	164.7	162.1	159.4	156.6	152.6	146.9	142.7	133.8
	Exhaust Temperature	°C	430.6	375.3	387.0	398.7	410.4	422.5	434.6	444.6	444.1	445.8	447.9	459.4
	Exhaust N_2	mol %	72.334	73.643	73.421	73.166	72.875	72.560	72.188	71.787	71.499	71.095	70.655	69.528
	Exhaust O_2	mol %	13.237	14.062	13.890	13.708	13.517	13.320	13.106	12.929	13.001	13.018	12.991	12.731
	Exhaust CO_2	mol %	3.106	2.849	2.905	2.961	3.016	3.072	3.128	3.163	3.089	3.026	2.982	2.960
	Exhaust Water	mol %	10.456	8.565	8.906	9.290	9.720	10.181	10.714	11.262	11.556	12.011	12.527	13.950
	GT Exhaust Argon	mol %	0.864	0.878	0.876	0.873	0.869	0.865	0.861	0.856	0.853	0.848	0.843	0.829
	GT Neon	mol %	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Nominal Exhaust Emissions	NOx	ppmvd 15 % O_2	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
		mg/m^3 15 % O_2	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4
		kg/hr	22.3	21.8	21.9	22.1	22.2	22.3	22.4	22.3	21.3	20.1	19.3	18.2
	CO	ppmvd 15 % O_2	0.0	84.4	77.1	70.6	64.5	59.1	54.2	50.3	48.2	47.0	46.2	45.2
		mg/Nm^3 15 % O_2	0.0	105.5	96.4	88.2	80.7	73.9	67.7	62.8	60.2	58.8	57.8	56.5
		kg/hr	0.0	44.8	41.2	37.9	34.9	32.1	29.5	27.3	24.9	23.1	21.8	20.0
	UHC (methane equivalent)	ppmvd 15 % O_2	0.0	16.9	15.4	14.1	12.9	11.8	10.8	10.1	9.6	9.4	9.2	9.0
		mg/Nm^3 15 % O_2	0.0	12.1	11.1	10.1	9.3	8.5	7.8	7.2	6.9	6.7	6.6	6.5
	VOC (methane equivalent)	ppmvd 15 % O_2	0.0	3.4	3.1	2.8	2.6	2.4	2.2	2.0	1.9	1.9	1.8	1.8
		mg/Nm^3 15 % O_2	0.0	2.4	2.2	2.0	1.9	1.7	1.6	1.4	1.4	1.3	1.3	1.3
	SOx (SO_2 equivalent)	ppmvd 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		mg/Nm^3 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Excelerate Energy, Lavaca Bay, OG2668

Industrial Trent Mechanical Drive, Wet Low Emissions Combustion system

Based on performance model eTrent v7.3.0

Metric Units	
Loss reference case	0
Fuel Temperature °C	50.0

Lean Hi Fuel Constituents

97.19% Methane (CH4)
.310% Ethane (C2H6)
.050% Propane (C3H8)
2.44% Nitrogen (N2)

	Parameters:		Ref	Nominal, 47617kW, 3361 rpm, Lean Hi Fuel										
	Case number		0	123	124	125	126	127	128	129	130	131	132	133
	Load Condition	% Base	100.00	80.71	80.71	80.71	80.71	80.71	80.71	81.43	86.52	92.61	97.46	100.00
Ambient Conditions	Altitude	m	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
	Barometric Pressure	kPa	101.325	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846	100.846
	Ambient Temperature	°C	15.0	-10.0	-5.0	0.0	5.0	10.0	15.0	20.0	25.0	30.0	34.0	41.0
	Ambient Relative Humidity	%	60.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Installation Losses	Inlet Loss	mm H_2O	101.60	90.17	90.95	90.39	89.15	87.90	86.67	86.32	85.87	85.42	85.01	79.23
	Exhaust Loss	mm H_2O	203.20	172.25	172.92	171.75	169.61	167.43	165.26	164.38	163.34	162.28	161.29	149.16
	Auxiliary Electrical Power Offtake	kWe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inlet Air Conditioning	Air Cooling Type		None	None	None	None	None	None	None	None	None	None	None	None
	Cooler Operative?		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Cooler Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Air Temperature	°C	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Post-Cooler Relative Humidity	%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Wet Compression Operative?		Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
	Wet Compression Water Flow	kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Engine Inlet Air Flow	kg/s	156.2	153.9	153.1	151.1	148.7	146.2	143.8	142.1	140.4	138.6	137.1	130.3
Performance	Engine Output Shaft Speed	rpm	3400.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0	3361.0
	Power kW	Engine Shaft	59001.0	47617.0	47617.0	47617.0	47617.0	47617.0	47617.0	47617.0	47617.0	47617.0	47617.0	45110.0
	Heat Rate (kJ/KWH, LHV)	Engine Shaft	8661.0	8869.9	8915.8	8955.6	8989.3	9018.8	9046.4	8903.0	8936.0	8966.0	8986.0	9080.0
	Efficiency % (LHV basis)	Engine Shaft	41.57	41.40	41.18	41.00	40.85	40.72	40.59	40.44	40.29	40.15	40.06	39.65
Combustion	GT Fuel Flow	kg/hr	10667.0	9330.0	9379.0	9420.0	9456.0	9486.0	9516.0	9552.0	9587.0	9619.0	9642.0	9229.0
	Fuel energy flow (LHV basis)	kW	141816.1	114922.6	115518.3	116027.7	116465.8	116842.7	117203.7	117650.6	118085.9	118481.5	118753.7	113676.4
	Combustor Water Injection Flow	kg/hr	12538.0	8141.0	8452.0	8732.0	8958.0	9051.0	9084.0	9067.0	8951.0	8703.0	8381.0	6893.0
Exhaust Composition	Exhaust Flow	kg/s	161.5	157.6	156.9	155.1	152.7	150.3	148.0	146.3	144.5	142.7	141.1	133.8
	Exhaust Temperature	°C	430.6	354.8	362.5	372.2	382.9	394.0	405.2	415.2	425.7	436.5	445.4	459.4
	Exhaust N_2	mol %	72.334	74.180	74.008	73.786	73.518	73.222	72.869	72.454	71.943	71.321	70.723	69.528
	Exhaust O_2	mol %	13.237	14.697	14.605	14.466	14.298	14.123	13.932	13.748	13.534	13.292	13.071	12.731
	Exhaust CO_2	mol %	3.106	2.606	2.629	2.668	2.715	2.763	2.810	2.846	2.884	2.921	2.951	2.960
	Exhaust Water	mol %	10.456	7.629	7.872	8.197	8.589	9.016	9.517	10.086	10.778	11.614	12.410	13.950
	GT Exhaust Argon	mol %	0.864	0.885	0.883	0.880	0.877	0.874	0.869	0.864	0.858	0.851	0.843	0.829
	GT Neon	mol %	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Nominal Exhaust Emissions	NOx	ppmvd 15 % O_2	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
		mg/m^3 15 % O_2	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4
		kg/hr	22.3	18.1	18.2	18.3	18.4	18.5	18.5	18.6	18.7	18.8	18.9	18.2
	CO	ppmvd 15 % O_2	0.0	100.2	90.9	82.9	75.9	69.7	64.3	59.1	54.5	50.3	47.3	45.2
		mg/Nm^3 15 % O_2	0.0	125.3	113.6	103.6	94.9	87.2	80.3	73.9	68.1	62.8	59.2	56.5
		kg/hr	0.0	44.2	40.3	37.0	34.0	31.4	29.0	26.7	24.8	23.1	21.8	20.0
	UHC (methane equivalent)	ppmvd 15 % O_2	0.0	20.0	18.2	16.6	15.2	13.9	12.9	11.8	10.9	10.1	9.5	9.0
		mg/Nm^3 15 % O_2	0.0	14.4	13.0	11.9	10.9	10.0	9.2	8.5	7.8	7.2	6.8	6.5
	VOC (methane equivalent)	ppmvd 15 % O_2	0.0	4.0	3.6	3.3	3.0	2.8	2.6	2.4	2.2	2.0	1.9	1.8
		mg/Nm^3 15 % O_2	0.0	2.9	2.6	2.4	2.2	2.0	1.8	1.7	1.6	1.4	1.4	1.3
	SOx (SO_2 equivalent)	ppmvd 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		mg/Nm^3 15 % O_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		kg/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

DRESSER-RAND

D-R Reference Nº 1-2DMYH
Issue Date 05-DEC-2012

Samsung Heavy Industries
RFQ Nº 9987-SHI-M00-5M-RQ-000002
Lavaca Bay LNG FLSO
Texas Gulf Coast

DR-61G4 SAC Predicted Performance Data

AVERAGE ENGINE PERFORMANCE DATA FOR DR-61G4
Assumptions:
Generator efficiency: 97.5%
Note: Generator Efficiency may change at different power rating.

SITE CONDITIONS:

Conditions:		**Base Scope - SAC with Water Injection for NOx suppression**						**Optional Scope - DLE**					
Ambient temperature	deg.C:	4.4	-10	-5	24	34	41	4.4	-10	-5	24	34	41
Altitude	meter:	27	27	27	27	27	27	27	27	27	27	27	27
Barometric press.	mBar:	1010	1010	1010	1010	1010	1010	1010.01	1010.01	1010.01	1010.01	1010.01	1010.01
Relative humidity	%:	60	60	60	60	60	60	60	60	60	60	60	60
Inlet pressure loss	mmH2O:	102	102	102	102	102	102	102	102	102	102	102	102
Exhaust pressure loss	mmH2O:	254	254	254	254	254	254	254	254	254	254	254	254
Fuel lower heat. value	kJ/kg:	47765	47765	47765	47765	47765	47765	47765	47765	47765	47765	47765	47765
GAS TURBINE PERFORMANCE:													

PT shaft speed	rpm:	3600	3600	3600	3600	3600	3600	3600	3600	3600	3600	3600	3600
Turbine power output	kW	36954	36404	36632	32888	29002	26278	34993	35974	36159	30382	27410	25358
Generator power output	kWe:	35938	35403	35625	31984	28204	25555	34031	34985	35165	29546	26656	24661
Heat rate	kJ/kWh:	9594	9495	9530	9774	9994	10219	9161	9067	9091	9436	9701	9936
Heat rate at Generator Terminal	kJ/kWeh:	10016	9912	9949	10203	10433	10668	9564	9514	9539	9851	10127	10373
Thermal efficiency	%:	37.53	37.93	37.78	36.84	36.03	35.24	39.31	39.72	39.61	38.16	37.12	36.24
Air flow rate at inlet	kg/s:	94.37	97.11	96.16	86.84	80.41	75.46	93.31	97.18	96.23	84.67	78.8	74.63
Exhaust flow	kg/s:	98.29	100.71	99.88	90.19	83.19	77.85	94.27	98.14	97.21	85.51	79.56	75.35
Total steam/water flow	kg/hr:	10083	9181	9538	8487	6882	5751	0	0	0	0	0	0
Fuel nozzle injection?		Water	Water	Water	Water	Water	Water	N/A	N/A	N/A	N/A	N/A	N/A
Fuel nozzle stm/wtr	kg/hr:	10083	9181	9538	8487	6882	5751	0	0	0	0	0	0
Total water flow w/margin	kg/hr:	11091	10099	10492	9336	7570	6326	0	0	0	0	0	0
Fuel noz. stm/wtr temp	deg.C:	60	60	60	60	60	60	0	0	0	0	0	0
EMISSION AND EXHAUST GAS DATA:													

Oxygen reference level	%	15	15	15	15	15	15	15	15	15	15	15	15
NOx emission	ppmv:	25	25	25	25	25	25	25	25	25	25	25	25
NOx emission	mg/Nm3:	51	51	51	51	51	51	51	51	51	51	51	51

DRESSER-RAND

D-R Reference Nº 1-2DMYH
Issue Date 05-DEC-2012

Samsung Heavy Industries
RFQ Nº 9987-SHI-M00-5M-RQ-000002
Lavaca Bay LNG FLSO
Texas Gulf Coast

DR-61G4 SAC Predicted Performance Data

AVERAGE ENGINE PERFORMANCE DATA FOR DR-61G4
Assumptions:
Generator efficiency: 97.5%
Note: Generator Efficiency may change at different power rating.

CO emission	ppmv:	76	81	83	35	21	15	25	25	25	25	25	25
CO emission	mg/Nm3:	95	101	104	44	27	19	31	31	31	31	31	31
CO2 emission	kg/s:	5.42	5.29	5.34	4.93	4.44	4.12	4.92	5	5.04	4.4	4.08	3.86
Mol. weight (kg/kmol):		27.977	28.083	28.047	27.897	27.821	27.719	28.479	28.522	28.507	28.352	28.209	28.056
Nitrogen	%vol:	71.566	72.294	72.05	70.983	70.425	69.692	75.116	75.416	75.313	74.203	73.178	72.089
Oxygen	%vol:	12.202	12.712	12.533	12.144	12.166	12.061	13.433	13.656	13.517	13.312	13.092	12.831
Water vapor	%vol:	11.856	10.766	11.136	12.557	13.185	14.079	7.173	6.717	6.905	8.279	9.565	10.944
Carbon dioxide	%vol:	3.508	3.351	3.408	3.462	3.377	3.332	3.375	3.304	3.359	3.312	3.285	3.269
Argon	%vol:	0.855	0.864	0.861	0.848	0.841	0.832	0.897	0.901	0.9	0.886	0.874	0.861
Sulfur dioxide	ppmv:	0	0	0	0	0	0	0	0	0	0	0	0
SOx emission rate	kg/hr:	0	0	0	0	0	0	0	0	0	0	0	0
SOx emission	tonnes/yr:	0	0	0	0	0	0	0	0	0	0	0	0
SOx emission	short ton/yr:	0	0	0	0	0	0	0	0	0	0	0	0
SOx emission rate	long ton/yr:	0	0	0	0	0	0	0	0	0	0	0	0
Nitrogen oxides	ppmv:	26	25	26	26	25	25	25	25	25	25	25	25
Carbon monoxide	ppmv:	80	81	85	36	22	15	25	25	25	25	25	25
Unb. hydrocarbons	ppmv:	22	23	24	7	3	2	15	15	15	15	15	14

	CUMMINS INC. Charleston, SC 29405 Marine Performance Curves	Basic Engine Model: **KTA50-DM1**	Curve Number: **DM-6886**	
		Engine Configuration: **D283036MX02**	CPL Code: **3729**	Date: **21-Oct-11**

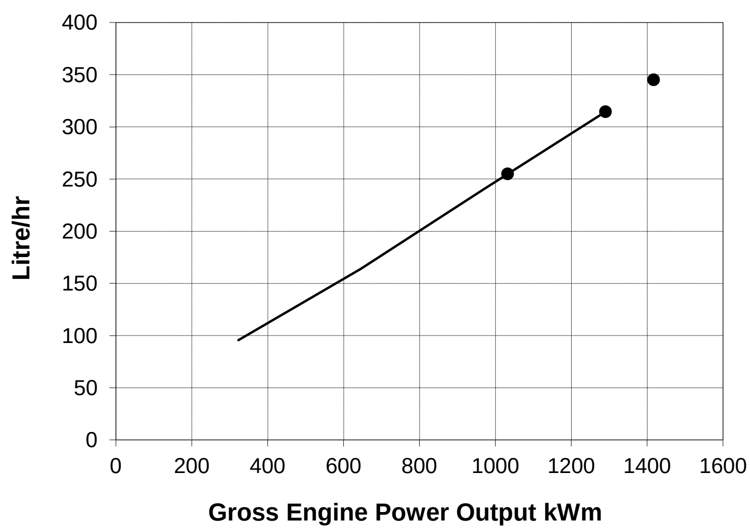
Displacement:	**50 liter**	**[3079 in³]**		kW [hp] @ rpm
Bore:	**159 mm**	**[6.26 in]**	Advertised Power:	**1290[1730]@1800**
Stroke:	**159 mm**	**[6.25 in]**	Aspiration:	**Turbocharged/Aftercooled**
Fuel System:	**PT**		Exhaust Type:	**Dry**
Cylinders:	**16**			

CERTIFIED: This marine diesel engine complies with or is certified to the:
IMO Tier II (Two) NOx requirements of International Maritime Organization (IMO), MARPOL 73/78 Annex VI, Regulation 13

Engine Speed	Overload Capacity		Prime Power		Continuous Power	
RPM	kWm	BHP	kWm	BHP	kWm	BHP
1800	1417	1900	1290	1730	1032	1384

Engine Performance Data @ 1800 rpm

OUTPUT POWER			FUEL CONSUMPTION			
%	kWm	BHP	kg/kWh	Lb/ BHP-h	Liter/ hour	U.S. Gal/ hour
10% OVERLOAD CAPACITY						
110%	1417	1900	0.207	0.341	345.2	91.2
PRIME POWER						
100%	1290	1730	0.207	0.341	314.6	83.1
75%	968	1298	0.211	0.347	239.9	63.4
50%	645	865	0.216	0.356	164.0	43.3
25%	323	433	0.252	0.414	95.5	25.2
10%	129	173	0.370	0.609	56.1	14.8
CONTINUOUS POWER						
80%	1032	1384	0.210	0.346	255.0	67.4



Rating Conditions: Ratings are in accordance with ISO 15550 and ISO 8528-5 reference conditions; air pressure at 100 kPa (29.61 in Hg), air temperature 25°C (77°F), and 30% relative humidity. The fuel consumption data is based on No. 2 diesel fuel weight at 0.85 kg/liter (7.0011 lb/U.S. gal).
Power output curves are based on the engine operating with fuel system, water pump, and lubricating oil pump; not included are battery charging alternator, fan, optional equipment, and driven components.
Unless otherwise specified, tolerance on all values is +/-5%.

Prime Power Rating is applicable for supplying continual electrical power at varied load. The following are the Prime Rating parameters:
* Prime Power is available for an unlimited number of hours per year in a variable load application. Variable load should not exceed a 70% average of the Prime Power rating during any operating period of 250 hours.
* The total operating time at 100% Prime Power shall not exceed 500 hours per year.
* There is a 10% overload capability for a period of 1 hour within a 12 hour period of operation. Total operating time at 10% overload shall not exceed 25 hours per year.

TECHNICAL DATA DEPT. **CHIEF ENGINEER**

Auxiliary Marine Engine Performance Data

Curve No.	**DM-6886**
DS :	**DS-4998**
CPL :	**3729**
DATE:	**21-Oct-11**

General Engine Data

Engine Model		KTA50-DM1			
Rating Type		Prime Power		Overload	
Rated Engine Power	kW [hp]	1290	[1730]	1417	[1900]
Governed Engine Speed	rpm		1800		
Rated HP Production Tolerance	±%		5		
Rated Engine Torque	N·m [lb·ft]	6844	[5048]	7516	[5544]
Low Idle Speed Range Minimum	rpm		725		
Low Idle Speed Range Maximum	rpm		775		
Maximum Torque Capacity from Front of Crank[2]	N·m [lb·ft]	4341	[3202]		
Brake Mean Effective Pressure	kPa [psi]	1705	[247]	1872	[272]
Compression Ratio			13.9:1		
Firing Order		1R-1L-3R-3L-2R-2L-5R-4L-8R-8L-6R-6L-7R-7L-4R-5L			
Friction Power	kW [hp]	168	[225]		
Weight Dry - Engine Only	kg [lb]	4853	[10700]		

Noise and Vibration

Average Noise Level - Top	(Idle)	dBA @ 1m	90
	(Rated)	dBA @ 1m	100
Average Noise Level - Right Side	(Idle)	dBA @ 1m	89
	(Rated)	dBA @ 1m	98
Average Noise Level - Left Side	(Idle)	dBA @ 1m	90
	(Rated)	dBA @ 1m	98

Fuel System[1]

Approximate Fuel Flow to Pump	l/hr [gal/hr]	609.5	[161.0]	609.5	[161.0]
Maximum Allowable Fuel Supply to Pump Temperature	°C [°F]	60	[140]	60	[140]
Approximate Fuel Flow Return to Tank	l/hr [gal/hr]	294.8	[77.9]	264.3	[69.8]
Approximate Fuel Return to Tank Temperature	°C [°F]	72	[162]	72	[162]
Fuel Rail Pressure	kPa [psi]	1000	[145]	1146	[166]
Average Fuel Consumption- ISO 8178 D2 Test Cycle	l/hr [gal/hr]	161.4	[42.6]		

Air System[1]

Intake Manifold Pressure	mm Hg [in Hg]	219	[65]	222	[66]
Intake Air Flow	l/sec [cfm]	1807	[3829]	1880	[3983]
Heat Rejection to Ambient	kW [Btu/min]	74	[4200]	88	[5000]

Exhaust System[1]

Exhaust Gas Flow	l/sec [cfm]	4394	[9311]	4681	[9918]
Exhaust Gas Temperature (Turbine Out)	°C [°F]	446	[834]	467	[872]
Exhaust Gas Temperature (Manifold)	°C [°F]	594	[1100]	624	[1155]
Heat Rejection to Exhaust	kW [Btu/min]	1053	[59940]	1157	[65872]

TBD= To Be Determined **N/A = Not Applicable** **N.A. = Not Available**

1 Unless otherwise specified, all data is at rated power conditions and can vary ± 5%.
2 No rear loads can be applied when the FPTO is fully loaded. Max PTO torque is contingent on torsional analysis results for the specific drive system. Consult Installation Direction Booklet for Limitations.
3 Heat rejection to coolant values are based on 50% water/50% ethylene glycol mix and do NOT include fouling factors. If sourcing your own cooler, a service fouling factor should be applied according to the cooler manufacturer's recommendation.
4 Consult option notes for flow specifications of optional Cummins seawater pumps, if applicable.

CUMMINS ENGINE COMPANY, INC

COLUMBUS, INDIANA

All Data is Subject to Change Without Notice - Consult the following Cummins intranet site for most recent data: http://marine.cummins.com

Auxiliary Marine Engine Performance Data

Curve No.	DM-6886
DS :	DS-4998
CPL :	3729
DATE:	21-Oct-11

Emissions (in accordance with ISO 8178 Cycle D2)

NOx (Oxides of Nitrogen)	g/kw·hr [g/bhp·hr]	6.843	[5.103]		
HC (Hydrocarbons)	g/kw·hr [g/bhp·hr]	0.299	[0.223]		
CO (Carbon Monoxide)	g/kw·hr [g/bhp·hr]	0.558	[0.416]		

Emissions (in accordance with ISO 8178 Cycle E2)

NOx (Oxides of Nitrogen)	g/kw·hr [g/bhp·hr]	7.220	[5.384]		
HC (Hydrocarbons)	g/kw·hr [g/bhp·hr]	0.249	[0.186]		
CO (Carbon Monoxide)	g/kw·hr [g/bhp·hr]	0.505	[0.376]		

Cooling System[1]

Sea Water Pump Specifications	MAB 0.08.17-07/16/2001				
Pressure Cap Rating (With Heat Exchanger Option)	kPa [psi]	103	[15]		

Two Loop Low Temperature Aftercooling (LTA)

Main Engine Circuit					
Coolant Flow to Main Cooler (with open thermostat)	l/min [gal/min]	1117	[295]		
Standard Thermostat Operating Range — Start to open	°C [°F]	82	[180]		
Standard Thermostat Operating Range — Full open	°C [°F]	95	[202]		
Heat Rejection to Engine Coolant[3]	kW [Btu/min]	481	[27367]	509	[28980]
Aftercooler (LTA) Circuit					
Coolant Flow to LTA Cooler (with open thermostat)	l/min [gal/min]	288	[76]		
LTA Thermostat Operating Range — Start to open	°C [°F]	63	[145]		
LTA Thermostat Operating Range — Full open	°C [°F]	80	[175]		
Heat Rejection to Engine Coolant[3]	kW [Btu/min]	227	[12908]	250	[14250]
Maximum Coolant Inlet Temperature from LTA Cooler — For Keel Cooled	°C [°F]	71	[160]		

TBD= To Be Determined   N/A = Not Applicable   N.A. = Not Available

1 Unless otherwise specified, all data is at rated power conditions and can vary ± 5%.
2 No rear loads can be applied when the FPTO is fully loaded. Max PTO torque is contingent on torsional analysis results for the specific drive system. Consult Installation Direction Booklet for Limitations.
3 Heat rejection to coolant values are based on 50% water/50% ethylene glycol mix and do NOT include fouling factors. If sourcing your own cooler, a service fouling factor should be applied according to the cooler manufacturer's recommendation.
4 Consult option notes for flow specifications of optional Cummins seawater pumps, if applicable.

CUMMINS ENGINE COMPANY, INC

COLUMBUS, INDIANA

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CUMMINS INC. Charleston, SC 29405 Marine Performance Curves	Basic Engine Model: QSK60-DM	Curve Number: DM-6771	
	Engine Configuration: D593009MX03	CPL Code: 3478	Date: 14-Jun-12

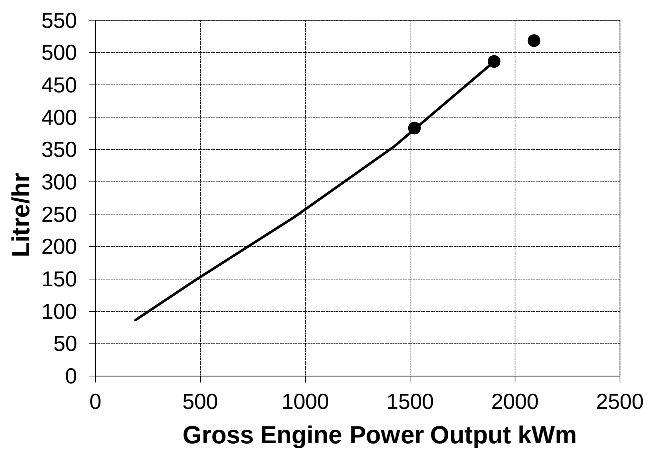
Displacement:	60.1726619125	[3672 in³]		kW [hp] @ rpm
Bore:	159 mm	[6.25 in]	Advertised Power:	**1900 [2547] @ 1800**
Stroke:	190 mm	[7.48 in]	Aspiration:	**Turbocharged / Low Temp. Aftercooler**
Cylinders:	16		Exhaust Type:	**Dry**
Fuel System:	**Modular Common Rail (MCRS) with C3.0 Injectors**			

CERTIFIED: This marine diesel engine complies with or is certified to the:
IMO Tier II (Two) NOx requirements of International Maritime Organization (IMO), MARPOL 73/78 Annex VI, Regulation 13
EPA Tier 2 - Model year requirements of the EPA marine regulation (40CFR94)
Rhine Ships Inspection Regulations as adopted by the Central Commision for Rhine navigation (CCNR)
EU Stage IIIa - EC Nonroad Mobile Machinery Directive (2004/26/EC)

Engine Speed	Overload Capacity		Prime Power		Continuous Power	
RPM	kWm	BHP	kWm	BHP	kWm	BHP
1800	2090	2802	1900	2547	1520	2038

Engine Performance Data @ 1800 RPM

OUTPUT POWER			FUEL CONSUMPTION			
%	kWm	BHP	Kg/ kW-h	Lb/ BHP–h	Liter/ hour	U.S. Gal/ hour
10% OVERLOAD CAPACITY						
110%	2090	2802	0.208	0.342	518.5	137.0
PRIME POWER						
100%	1900	2547	0.215	0.353	486.3	128.5
75%	1425	1910	0.209	0.344	355.1	93.8
50%	950	1273	0.217	0.357	246.1	65.0
25%	475	637	0.261	0.430	148.0	39.1
10%	190	255	0.380	0.626	86.2	22.8
CONTINUOUS POWER						
80%	1520	2038	0.211	0.348	383.4	101.3



Rating Conditions: Ratings are in accordance with ISO 15550 and ISO 8528-5 reference conditions; air pressure at 100 kPa (29.61 in Hg), air temperature 25°C (77°F), and 30% relative humidity. The fuel consumption data is based on No. 2 diesel fuel weight at 0.85 kg/liter (7.001 lb/U.S. gal).

Power output curves are based on the engine operating with fuel system, water pump, and lubricating oil pump; not included are battery charging alternator, fan, optional equipment, and driven components.

Values from engine control modules and displayed on instrument panels are not absolute. Tolerance varies, but is generally less than +/-5% when operating within 30% of rated power.

Unless otherwise specified, tolerance on all values is +/-5%.

Prime Power Rating is applicable for supplying continual electrical power at varied load. The following are the Prime Rating parameters:
* Prime Power is available for an unlimited number of hours per year in a variable load application. Variable load should not exceed a 70% average of the Prime Power rating during any operating period of 250 hours.
* The total operating time at 100% Prime Power shall not exceed 500 hours per year.
* There is a 10% overload capability for a period of 1 hour within a 12 hour period of operation. Total operating time at 10% overload shall not exceed 25 hours per year.

TECHNICAL DATA DEPT. **CHIEF ENGINEER**

Auxiliary Marine Engine Performance Data

Curve No.	DM-6771
DS :	D59-MX-1
CPL :	3478
DATE:	14-Jun-12

General Engine Data

Engine Model	QSK60-DM			
Rating Type	Prime Power		Overload	
Rated Engine Power ....kW [hp]	1900	[2547]	2090	[2802]
Governed Engine Speed ....rpm		1800		
Rated HP Production Tolerance ....±%		3		
Rated Engine Torque ....N·m [lb·ft]	10076	[7432]	11084	[8176]
Default Idle Speed Setting....rpm		800		
Low Idle Speed Range — Minimum ....rpm		600		
Low Idle Speed Range — Maximum ....rpm		1200		
Brake Mean Effective Pressure ....kPa [psi]	2104	[305]	2315	[336]
Compression Ratio		14.5		
Piston Speed ....m/sec [ft/min]	11	[2245]		
Firing Order	2-1-6-5-4-3-10-7-16-15-12-11-14-13-8-9			
Steady State Stability Band at Constant Load ....%		[5]		
Weight Dry - Engine Only ....kg [lb]	8754	[19300]		
Weight Dry - Engine With Heat Exchanger ....kg [lb]	9136	[20142]		

Noise and Vibration

Average Noise Level - Top	(Idle).. ....dBA @ 1m	N.A.	
	(Rated) ....dBA @ 1m	106	
Average Noise Level - Right Side	(Idle).. ....dBA @ 1m	N.A.	
	(Rated) ....dBA @ 1m	105	
Average Noise Level - Left Side	(Idle).. ....dBA @ 1m	N.A.	
	(Rated) ....dBA @ 1m	105	

Fuel System¹

Approximate Fuel Flow to Pump ....l/hr [gal/hr]	964.7	[254.8]	999.9	[264.1]
Maximum Allowable Fuel Supply to Pump Temperature ....°C [°F]	60	[140]	60	[140]
Approximate Fuel Flow Return to Tank ....l/hr [gal/hr]	478.4	[126.4]	481.4	[127.2]
Approximate Fuel Return to Tank Temperature ....°C [°F]	51	[123.3]	52	[125.78]
Maximum Heat Rejection to Drain Fuel ....kW [Btu/min]	2.6	[150]	3.0	[170]
Fuel Rail Pressure ....kPa [psi]	150000	[21756]	160000	[23206]
Average Fuel Consumption- Emissions ISO 8178 D2 Test Cycle....l/hr [gal/hr]	239.8	[63.4]		

Air System¹

Intake Manifold Pressure ....mm Hg [in Hg]	315	[92.9]	331	[97.7]
Intake Air Flow ....l/sec [cfm]	3009	[6375]	3119	[6608]
Heat Rejection to Ambient ....kW [Btu/min]	84	[4799]	90	[5144]

Exhaust System¹

Exhaust Gas Flow ....l/sec [cfm]	6741	[14283]	7041	[14920]
Exhaust Gas Temperature (Turbine Out) ....°C [°F]	418	[784.4]	430	[806]
Exhaust Gas Temperature (Manifold) ....°C [°F]	614	[1136]	637	[1178]
Heat Rejection to Exhaust ....kW [Btu/min]	1594	[90717]	1715	[97615]

TBD= To Be Determined N/A = Not Applicable N.A. = Not Available

1 Unless otherwise specified, all data is at rated power conditions and can vary ± 5%.
2 No rear loads can be applied when the FPTO is fully loaded. Max PTO torque is contingent on torsional analysis results for the specific drive system. Consult Installation Direction Booklet for Limitations.
3 Heat rejection to coolant values are based on 50% water/50% ethylene glycol mix and do NOT include fouling factors. If sourcing your own cooler, a service fouling factor should be applied according to the cooler manufacturer's recommendation.
4 Consult option notes for flow specifications of optional Cummins seawater pumps, if applicable.

CUMMINS ENGINE COMPANY, INC

COLUMBUS, INDIANA

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Auxiliary Marine Engine Performance Data

Curve No.	DM-6771
DS :	D59-MX-1
CPL :	3478
DATE:	14-Jun-12

Emissions (in accordance with ISO 8178 Cycle D2)

NOx (Oxides of Nitrogen) ......g/kw·hr [g/bhp·hr]	6.45	[4.81]		
HC (Hydrocarbons) ......g/kw·hr [g/bhp·hr]	0.25	[0.19]		
CO (Carbon Monoxide) ......g/kw·hr [g/bhp·hr]	1.51	[1.13]		
PM (Particulate Matter) ......g/kw·hr [g/bhp·hr]	0.14	[0.10]		

Emissions (in accordance with ISO 8178 Cycle E2)

NOx (Oxides of Nitrogen) ......g/kw·hr [g/bhp·hr]	6.48	[4.83]		
HC (Hydrocarbons) ......g/kw·hr [g/bhp·hr]	0.21	[0.16]		
CO (Carbon Monoxide) ......g/kw·hr [g/bhp·hr]	0.96	[0.72]		
PM (Particulate Matter) ......g/kw·hr [g/bhp·hr]	0.11	[0.08]		

Cooling System[1]

Sea Water Pump Specifications ......MAB 0.08.17-07/16/2001				
Pressure Cap Rating (With Heat Exchanger Option) ......kPa [psi]	103	[15]		

Two Loop Low Temperature Aftercooling (LTA)

Main Engine Circuit

Coolant Flow to Main Cooler (with open thermostat)......l/min [gal/min]	1211	[320]		
Standard Thermostat Operating Range — Start to open......°C [°F]	82	[180]		
Standard Thermostat Operating Range — Full open......°C [°F]	95	[202]		
Heat Rejection to Engine Coolant³ ......kW [Btu/min]	536	[30487]	594	[33801]

Aftercooler (LTA) Circuit

Coolant Flow to LTA Cooler (with open thermostat)......l/min [gal/min]	511	[135]		
LTA Thermostat Operating Range — Start to open......°C [°F]	46	[115]		
LTA Thermostat Operating Range — Full open......°C [°F]	57	[135]		
Heat Rejection to Engine Coolant³ ......kW [Btu/min]	621	[35327]	645	[36715]
Maximum Coolant Inlet Temperature from LTA Cooler — For Keel Cooled......°C [°F]	49	[120]		

Engines with Radiator Cooling

Main Engine Circuit

Coolant Flow to Main Cooler (with open thermostat)......l/min [gal/min]	1817	[480]		
Standard Thermostat Operating Range — Start to open......°C [°F]	82	[180]		
Standard Thermostat Operating Range — Full open......°C [°F]	95	[202]		
Heat Rejection to Engine Coolant³ ......kW [Btu/min]	536	[30487]	594	[33801]

Aftercooler (LTA) Circuit

Coolant Flow to Radiator (Blocked open thermostat) ......l/min [gal/min]	511	[135]		
Standard Thermostat Operating Range — Start to open......°C [°F]	46	[115]		
Standard Thermostat Operating Range — Full open......°C [°F]	57	[135]		
Heat Rejection to Engine Coolant³ ......kW [Btu/min]	621	[35327]	645	[36715]
Maximum Coolant Inlet Temperature from LTA Cooler — For Radiator @ 35° C [95° F] Ambient Air......°C [°F]	49	[120]		
For Radiator @ 50° C [122° F] Ambient Air......°C [°F]	68	[155]		

TBD= To Be Determined   N/A = Not Applicable   N.A. = Not Available

1 Unless otherwise specified, all data is at rated power conditions and can vary ± 5%.
2 No rear loads can be applied when the FPTO is fully loaded. Max PTO torque is contingent on torsional analysis results for the specific drive system. Consult Installation Direction Booklet for Limitations.
3 Heat rejection to coolant values are based on 50% water/50% ethylene glycol mix and do NOT include fouling factors. If sourcing your own cooler, a service fouling factor should be applied according to the cooler manufacturer's recommendation.
4 Consult option notes for flow specifications of optional Cummins seawater pumps, if applicable.

CUMMINS ENGINE COMPANY, INC

COLUMBUS, INDIANA

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NAME	**: Samsung Heavy Industries & Construction Co. Ltd.**			
ADDRESS	:			
CITY	:		Date	: 14-Jan-2013
			ref	: CHL901435
COUNTRY	: Korea		phone	: +31(0)24 3523100
ATT	**:**			
YOUR REF.	: Lavaca bay - 250K LNG FLSO			

T E C H N I C A L   S P E C I F I C A T I O N

INERT GAS GENERATOR

Type : **Smit Gas™ GIn 15.000 - 0.25 BUFD**

Project no.: 65080TS(LNG) rev 0 dated 14-01-13

Order no. : based on rev. /dtd.

This specification consists of 15 pages.

REV	DATE	BY	PAGE
0	14-Jan-2013		

This specification covers a generator for the production of inert gas by combustion of fuel oil.

GENERATOR TYPE	Smit Gas™ GIn 15.000 - 0.25 BUFD
APPLICATION	shipboard use
CLASSIFICATION	ABS

I. SCOPE OF SUPPLY

I.1. MECHANICAL COMPONENTS

- Inert gas generator, consisting of combustion chamber, Smit Ultramizing burner and cooling/scrubbing section
- 2pc 50% combustion-air blowers, with silencer, flexible connection and E-motor (IP 44)
- Fuel-oil pump with motor, filters, valves and oil line
- R-407c cooling unit with control panel and E-motor
- Heat regenerated adsorption dryer unit with control panel, heater fan and motor

I.2. VALVES

- Pneumatic pressure control valve
- Pneumatic discharge and purge gas valves (fail safe)
- Water discharge control valve with level control system
- Other valves integrated in the system
- Vacuum breaker valve

I.3. INSTRUMENTATION AND CONTROL PANELS

- Local control room panel (LCRP), fully wired, with indicating Lamps inserted in mimic diagram
- Oxygen analyser
- Dewpoint analyser
- Motor starter panels
- Various safety devices and alarms.

I.4. DOCUMENTATION

- Maintenance and instruction manuals (4 copies in English)
- Classification certificate and test protocol.

I.5. THE FOLLOWING ITEMS ARE NO PART OF OUR STANDARD DELIVERY:

I.5.1. No part of delivery:

- Seawater pumps and filters
- Piping for fuel-oil and cooling-water supply and discharge
- Interconnecting piping
- Insulation and tracing
- Electrical supply to the unit and interconnecting cabling incl. cable glands
- Erection on board and connection to your piping
- Ventilation of generator room.

I.5.2. Optional

- Spare parts
- Commissioning.
- Water supply valve (needed in case of use of non dedicated pump)
- More extensive spares according separate list

II. SPECIFICATIONS

II.1. INERT GAS SPECIFICATION

Capacity	fixed:	15000 Nm^3/h (100% mode) or 7500 Nm^3/h (50% mode)
Discharge pressure		0.25 barg

Typical gas composition (on dry basis)

Oxygen	O_2	max. 0,5 vol%
Carbon-dioxide	CO_2	approx. 14 vol%
Carbon-oxide	CO	max. 100 ppm
Sulphur-oxides	SO_x	max. 1 ppm
Nitrogen	N_2	balance
Soot (on Bacharach scale)		0 (= complete absence)

Temperature	about 30°C average (max. 65°C during switch-over of dryer vessels)
Dewpoint	max. -45°C after expansion to atmospheric pressure

II.2. UTILITIES

Fuel oil

Quality	Marine Fuel grade according to ISO 8217 grade DMA or DMB
Inlet pressure	atmospheric
Consumption	abt. 1451 kg/h at design capacity

Combustion air (ambient)

Temperature	max. 50°C
Pressure	atmospheric
Consumption for combustionabt.	17114 Nm^3/h
Consumption for regeneration	abt. 7500 Nm^3/h

Note: Sufficient ventilation is obligatory.

Electricity

Power supply	440V, 3ph, 60Hz			
Control supply	220V, 1ph, 60Hz			
Power failure supply	24V, DC, 0,05 kW			
	Rating		Consumption	
Combustion-air blower motor	184	kW	177	kW (each 2x50%)
Fuel-oil pump motor	5	kW	2,2	kW
R-407c compressor motor	250	kW	165	kW
Chiller water pump	7,5	kW	6	kW
Dryer fan motor	65	kW	39	kW
Dryer heater	77	kW	77	kW (optional)
Control system	3.0	kW	3	kW

Cooling water

Quality	filtered seawater, (mesh size 4 mm)
Supply pressure:	constant value,between 2-4 barg
Outlet pressure	atmospheric
Inlet temperature	max. 32 °C
Consumption: - generator unit	1433 m^3/h

Fresh water

Supply rating		4 m^3/h for rinsing		
Supply pressure		1 bar(g) min.		
Supply temperature		36 °C max		
Consumption	- refrig. unit	200 m^3/h	heat dissipation	622 kW
	- dryer cooler	56 m^3/h	heat dissipation	325 kW

Instrument air

Quality	free from dust, oil and condensed water under all operating conditions
Supply pressure	6-9 barg
Rating	20 Nm^3/h
Consumption per start for pilot Burner	170 litres
Consumption for pneumatic equipment	2 Nm^3/h

Steam

Pressure		9-10 bar(g)
Temperature		max. 250°C
Consumption:	- main burner	3623 kg/h
	- dryer heater	500 kg/h

II.3. NOISE LEVEL

Noise produced by each blower	abt. 100 dB(A) measured at 1 metre distance in free field

II.4. DOCUMENTS:

Diagrams	Drawing
Flow diagram inert gas generator	SBUFD0C1-1
Flow diagram inert gas cooler	65225002R00
Flow diagram dryer	SBUFD0C3-1
Diagram 02 analyser	SBUFD004
Diagram dewpoint meter	SBUFD005
Flow diagram R-407c chiller unit	65095006R02

Dimensional drawings (preliminary)*

Inert gas generator	P-G00002
Air blower	P-B00001
R-407c unit	65095A424R01 and P-F00041
Dryer unit	P-D00024

Other

Guidelines for installing supply and discharge piping	65080052
Mounting instruction	65080051R02
Flow meter arrangement	P-P00332 (if applicable)
Symbols table	SSYMX005

II.5. ENGINEERING BASIS

Design basis

- The unit is designed and will be built in accordance with the regulations of IMO and the rules of the classification society, based on UMS unless otherwise required.
- Shipboard use, indoor erection.
- Capacity of ig generator is based on ambient air of 25 C and 100% RH
- Dryer may have some minutes off spec on dewpoint during switch-over of vessels.
- Quantities tolerances +/- 3%.
- Temperatures tolerances +/- 2°C.
- Pressures tolerances (effective working pressures) +/- 5%.
- Voltage tolerances: - 15% / + 10%.
- Noise tolerance: +/- 2 dBA
- Combustion chamber cooling water jacket is designed for 1 bar overpressure maximum.
- Interface flanges according to JIS.
- Effluent water seal mounted straight under generator based on delta pressure control.
- Electric motors switched directly on line.
- Process safeguarded by several protecting devices.
- Signalization 24 V - 60 Hz.
- Instrumentation: Thermowell will be used for liquids, pressure sensors will have 3-way valves and the level switch will have a test lever.
- Rinsing with fresh water need be as follows:
  - R-407c cooling unit: for 15 minutes
  - Combustion chamber jacket (2 hours after stop): 15 to 30 min.

II.6. STANDARD MATERIALS

Generator

- Air and fuel-oil piping	mild steel
- Combustion chamber	stainless steel AISI 316L
- Cooling/scrubbing section	stainless steel AISI 316L
- Filling materials	polypropylene
- Demister	stainless steel AISI 316
- Demister holder	stainless steel AISI 316

R-407c refrigeration unit

- Condenser:	shell	seamless mild steel
	water headers	nodular cast iron
	tubes	SF-Cu (CuNi10FeMn for seawater)
	tube plates	mild steel (cladded with Cu/Ni 70/30 in case of sea water
- Inert gas cooler:	shell	mild steel
	tubes	stainless steel AISI 316L
	tube plates	stainless steel AISI 316L
	headers	stainless steel AISI 316L

- Demister	stainless steel AISI 316
- Demister holder	stainless steel AISI 316L.

Dryer unit:

- Vessels and piping	mild steel
- Adsorbent	activated alumina

Advised materials for interconnecting piping:

- Between blower and burner	mild steel
- Between scrubbing tower and R-407c refrigeration unit	stainless steel
- Between R-407c refrigeration unit and dryer	stainless steel
- Behind dryer (indoor)	mild steel.

II.7. COATING SYSTEM

- Stainless steel parts will be cleaned from impurities.
- Control panels will have finish coat according RAL 7035.
- Main components from our subsuppliers may have their own coating.
- Indoor, steel parts will be shotblasted (SA 2½) and painted with one layer of primer and one layer of finish (Munsell 7.5 7/2).

II.9. LINE SIZES

See partslist PID's

III. GENERAL DESCRIPTION OF THE BUFD TYPE GAS GENERATORS

III.1 WORKING PRINCIPLE

Inert gas is produced by the combustion of oil with air, followed by further treatments in order to obtain the required quality and properties.
The combustion is a chemical reaction between the hydrocarbon and the oxygen, mainly producing carbon dioxide and water. The water is condensed for the greater part. The nitrogen of the air leaves the generator unchanged. Some small rest quantities of carbon monoxide and hydrogen may remain. Thus, the inert gas produced mainly consists of nitrogen and CO_2.

The hot combustion gases are cooled, first indirectly in the combustion chamber by a seawater-cooled jacket. The principal cooling, however, occurs afterwards in the cooling section.
Because of the intense contact between inert gas and seawater in this cooling tower, the inert gas temperature is decreased close to the seawater temperature, while corrosive sulphur oxides are washed out of the inert gas.
The cooling/scrubbing water leaves the generator through the waterseal.
At the end of the cooling section the gas is passed through a demister to separate the water droplets from the gas stream.

Further removal of the water takes place in two steps. The gas is cooled down in a R-407c refrigeration unit first. The bulk of the water present in the gas is condensed and drained.
Then in the final stage, the water is removed by adsorption in a desiccant dryer.
The required final pressure of the gas is achieved by the air blower supplying the combustion air to the burner.
The pressure inside the plant is maintained constant to ensure a stable flame during operation, independent of pressure fluctuations in the piping system. This is done via a pressure control valve at the end of the installation.

III.2. BLOWER UNIT

The air required for combustion is supplied by means of 2 blowers unit. These units are direct or V-belt driven and mounted on a frame with vibration isolators, guard, flexible hose connection, combined filter suction silencer.

III.3. ULTRAMIZING BURNER

A good combustion process is the first requirement for a reliable inert gas generator.
The burner is of our special design, according to the Smit Ultramizing System.
In this design the fuel oil is atomised in two steps. First a conventional nozzle sprays the oil, supplied under pressure to the burner. Then the oil spray is subjected to a tangential impulse flow of steam, which added to the mainly axially orientated impulse flow of the oil spray itself, results in an ultra-fine dispersion of the liquid.
The tangential impulse flow of combustion steam is created by supplying the steam through slots in an atomising ring, which is fitted at the end of the burner gun.
This combustion process guarantees that absolutely no soot will be produced, not even at understoichiometric conditions, e.g. during combustion-air shortage, caused by a lower speed of the combustion air blower, which could occur by voltage and/or frequency fluctuations in the electrical supply.
Soot cannot be tolerated in the plant, neither in the ship's cargo tanks nor in the piping system.
To prevent soot formation, especially on the long run, a stable and well-balanced combustion process is obligatory.

III.4. INERTGAS GENERATOR

The combustion chamber is cooled by a water jacket.
Scaling in the cooling-water jacket of the combustion chamber is prevented both by the low temperature rise and the positioning of the openings for the supply and discharge of the seawater.
The inert gas coming from the burner has a rather high temperature and contains sulphur oxides.
In the cooling/scrubbing section the construction ensures an intense contact between gas and water, reducing the inert gas temperature and the content of sulphur oxides.
Water droplets are separated, by means of a demister, before the gas leaves the generator.

III.5. REFRIGERATION UNIT (FREON R-407C)

This unit cools the required quantity of inert gas or dry air with a relative humidity of 100%, from + 35 °C to about + 5 °C (average).
The capacity of the plant is controlled automatically over a range of 0 - 100% to adapt the cooling capacity to the seawater temperature, which may vary between 0 and 32 °C. This is necessary to prevent the condensing water from freezing.
The materials applied in the inert gas cooler are adapted to the presence of seawater vapours in the inert gas.

The unit consists of:

- Inert gas cooler by cold water (water/glycol mixture).
- Demister unit to separate droplets from the inertgas
- Water (water/glycol mixture) cooling unit with:
    - Compressor unit with capacity control (slide valve control) followed by hot gas flowing from a high pressure side of the compressor through a by-pass control valve via the inlet of the evaporator to the suction of the compressor.
    - Electronic expansion valve(s).
    - Water chiller by refrigerant R-407c
    - R-407c condenser
    - Water circulation pump with E-motor
- All safety equipment

The refrigeration unit supplies the inert gas to the inert gas dryer.

III.6. INERT GAS DRYER

In this equipment the inert gas is dehumidified to the required final dewpoint. Drying is now effected by a desiccant, adsorbing the water still contained in the inert gas.
The inert gas dryer has two vessels, while one vessel is in drying operation, the second vessel is being regenerated.
The change-over from drying operation to regeneration is automatically controlled.
Provisions have been included to ensure that the regeneration process will be fully completed after the generator has been stopped.

Vessel change-over takes place after several hours. Regeneration occurs by flushing the vessel with hot air of max 149 °C. No inert gas is required then. The water in the adsorbent is evaporated by the hot air and carried off in the flushing stream.
Heating of the air will be done by steam (electrical is optional).
The dryer has to be insulated.
Insulation by the yard should be done by glass wool of 50 mm thick.

Maximum three and a half hours are used for flushing with hot air (5440 closed, 5401 open, steam and/or electric heaters in operation).

The temperature of the regeneration air is controlled by the electric. The hot air goes in counterflow through the vessel that just finished the adsorption period and was depressurised (5016/5026 valve is open for depressurisation via 5453, valves 5011/5021 and 5081/5091 are open during adsorption).
The hot air leaves the vessel via 5016/5026.

The regeneration is stopped on the regeneration air temperature (5057). Now the cooling period starts. Valve 5440 opens, while 5401 closes (automatically). At the same time valve 5031 opens to fill the cooling circuit with dry inert gas via 5085/5095. Valve 5450 keeps the circuit under a slight over-pressure (abt. 200 mm WC). 5031 remains open.
The water valve for the cooler opens (5432) and the fan circulates the cooled inert gas. If the vessel is cooled, both inlet/outlet valves will be open for 1 hour (5016, 5026, 5011, 5021 all open) to have parallel drying of both vessels.
The regenerated vessel is now ready for the next adsorption period alone.

III.7. PRESSURE CONTROLSYSTEM

A pressure control valve maintains a constant pressure in the inert gas generator system, in order to guarantee the specified gas quality.
The pressure in the inert gas generator is not affected by variations behind the pressure control valve.

III.8. ELECTRICAL EQUIPMENT

III.8.1. Panels

The system has several panels for starting, control and safeguarding.
The communication system will be based on serial link according Modbus.

- One main separately installed control panel to control the inert gas generator (combustion and scrubbing) and the whole system.
  This panel is giving 'instructions' to the local panels (automatic starting of fuel-oil pump and blower, checking conditions on R-407c and dryer site). It has a mimic diagram in the front.
  In case of a failure, a sound will be given and the direct cause of the failure will be indicated in the mimic.

- One starter panel for fuel oil pump, for mounting close to the motor.

- One starter panel for blower, for mounting close to the motor.
  Both panels contain a circuit breaker (with manual and automatic disconnector), thermal overload protection, starter relays and hour counter (ammeter is optional).

- One control/starter panel, mounted on the R-407c skid for fully independent starting and control of the R-407c unit, completely cabled to the components on the skid, with mimic in the front.

- One control/starter panel, mounted on the dryer skid for fully
  Independent starting and control of the dryer unit completely cabled to the components on the skid, with mimic in the front.

III.8.2 Electric motors and starters.

The motors used will be squirrel cage type (insulation class F, temperature rise B) with SPM nipples for vibration measurement (equipment by others). Also element type stand-still heaters will be installed. The IP class will be at least IP44.The sealed motor of the refrigeration compressor will deviate from above.
Motors over 100 KW will have PT-100's with a spare
The starters used will be suitable for direct on line (DOL) starting of the motors. Also ammeters will be installed. The entry from the bottom of the panels will be coaming type. The air blowers will have running an indication.

III.8.3. Electrical connection of the various main parts

All electrical equipment on the inert gas generator main units will be cabled. All cables will end in a connecting box fitted to the generator and in the control panels on the R-407c and dryer unit.

We deliver a diagram of connections with numbers and sizes of cables, and showing the terminal numbers of all electrical equipment delivered by us.
Cable glands will be installed

III.9. PROTECTIONS AND SAFETY DEVICES

The generator is equipped with several protections and safety devices, which are partly shown in the flow diagram.
There are direct and indirect-acting protections and safety devices.
Direct-acting protections are breakers, pressure relief valves and waterseal; they are operated by the medium they have to protect.
Indirect-acting protections are components which continuously compare the actual process value to a set value; if this set value is reached or exceeded, they will give a signal to the signalising system which undertakes the required actions in the generator operations.
Combined with limit switches, these protections and safety devices form a series of conditions for safe and proper operation.
The high water level alarm of the washing/scrubbing tower will be always alert, also if the generator is totally switched-off; this alarm is fed by the ship's emergency system.

III.10. OXYGEN CONTENT MEASUREMENT

The classification authorities prescribe a continuous check (indication and alarm) of the oxygen content in the inert gas.
The analyser constantly indicates the oxygen content in the inert gas and will effect an alarm when a set maximum or minimum quantity of oxygen is exceeded.
The highest value is determined by the application of the inert gas.

The lowest value protects against under-stoichiometric combustion (too high content of combustibles CO + H2).
The generator will not stop at alarm condition.
This enables the operator to change the adjustment of the fuel/air ratio and to see the result.
The inert gas produced is purged at alarm condition.
For remote indication or recording a 4-20 mA signal is available.

III.11. OPERATION

- First of all handvalves for utilities (seawater, fuel, etc.) will be opened.
- Main switch is actuated.
- Switch for starting R-407c refrigeration unit and dryer is actuated.
- Now the generator can be started by operating a switch.
  This is possible, since the complete starting process is fully programmed and safeguarded.
- The purge line is open when the generator is started.

  The starting program runs as follows:

- The blower purges the system with air before the pilot burner is ignited by a spark plug.
- The pilot burner is ignited; as soon as the flame is detected the main burner is started.
- After flame detection of the main burner and flame stabilization, the pilot burner is shut down.
- After 4 minutes of purging after start, the delivery line is opened and the purge line closed, provided that the oxygen content is correct. If not, the purge line remains open until the correct fuel/air ratio has been set and the correct oxygen content is obtained.
- For longer standstill periods it is recommended to purge the seawater cooling system with fresh water.
- An extra contact is available in the control panel for connection to the ship's main control room to allow for a remote stop of the generator.

III.12. MAINTENANCE

Hardly any maintenance is required owing to the application of high-quality components and the selective choice of materials.
Components requiring maintenance as well as vital parts will be always situated at a readily accessible place.
In the instruction manual you will find a clear description of the maintenance procedures.

III.13. TESTING

The following tests will be done before delivery:

- Functional test of the fully wired electric control box.
- Proper functioning of all alarms and safety devices (partly by simulation).
- Proper functioning of the starting-up sequence.
- High voltage test (2 KV-AC for 1 minute between phases and earth).
- Insulation resistance test with 1000 V DC between phases and earth.

III.14. DOCUMENTATION

In case of an order we will supply you with the following documents in English:

- Arrangement drawing, showing all dimensions required
- Engineering schematic diagram with parts list
- Electrical key diagram
- Electrical diagram of connections
- Operation and maintenance instruction manuals
- Spare parts list for two years' operation.

III.15 LIST OF DEVIATIONS

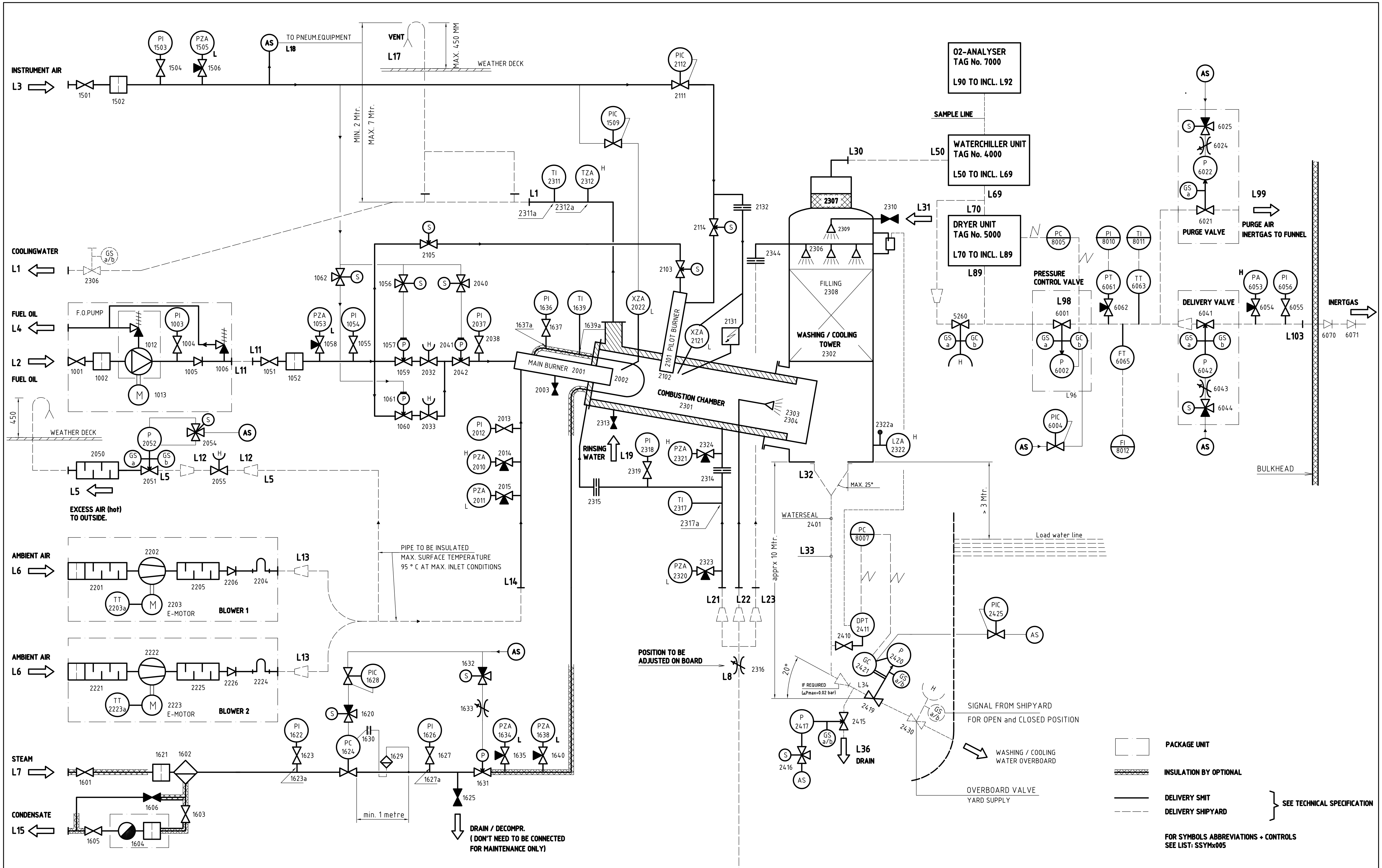
To POS *** revision **dated ** , total ** pages

To General Specification*** revision **dated ** , total ** pages

To Technical Specification*** revision **dated ** , total ** pages

To Electrical Equipment Specification**** revision **dated ** , total ** pages

AALBORG INDUSTRIES INERT GAS SYSTEMS B.V.



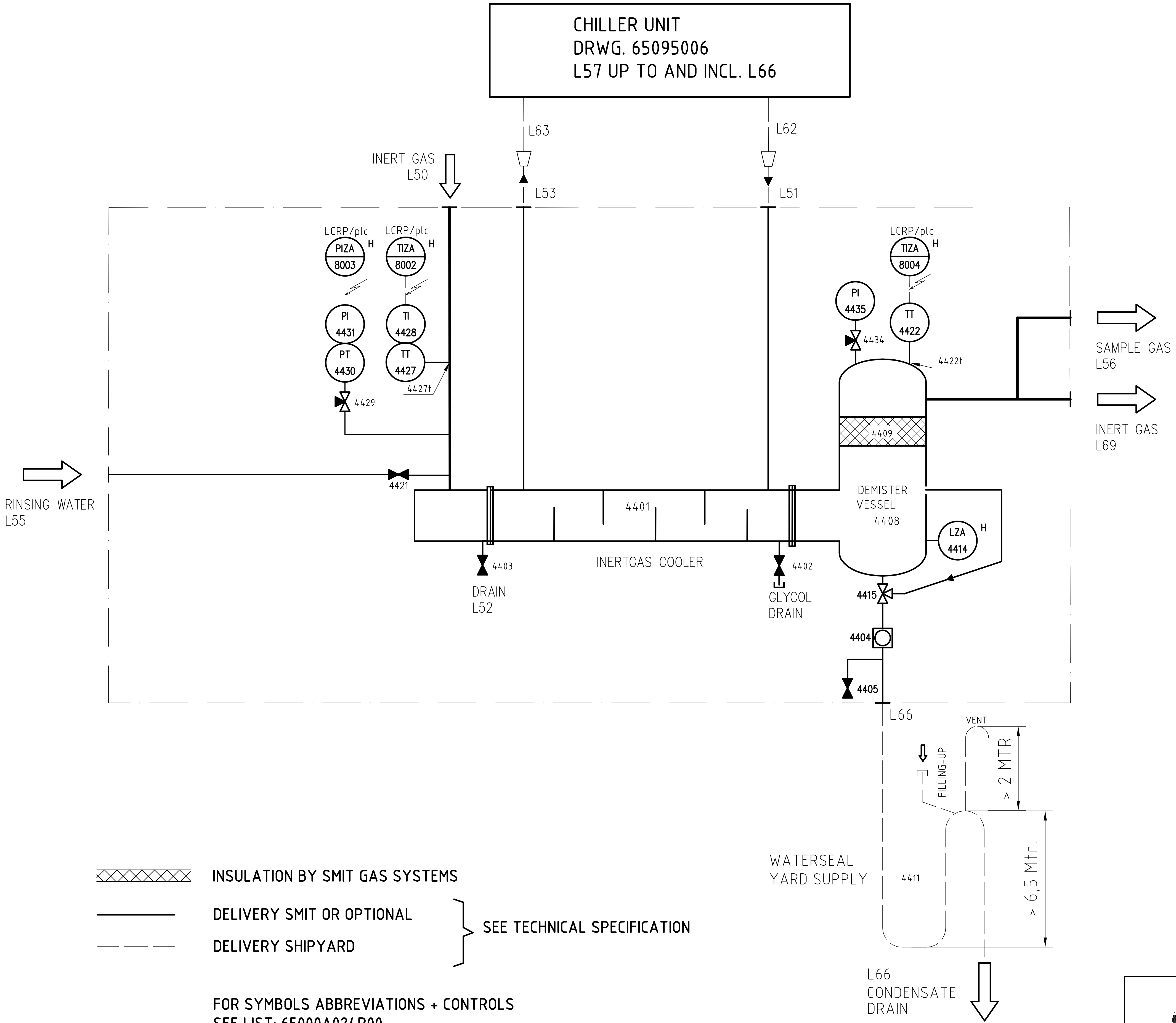
DWG. TITLE:	SCHEMATIC DIAGRAM I.G. GENERATOR
CLIENT REF.:	
ORDER/PROJECT NO.:	
REF. DWG.:	18935001
DATE:	28-08-05
DRW.:	GLi
CHK'D:	
DWG. NO.:	SBUFDC1-1
FORMAT:	A1
SCALE:	
REV.:	02

TOLERANCES UNLESS OTHERWISE SPECIFIED ACCORDING TO: ISO2768 - M

PROJECTION:

SMIT GAS SYSTEMS

Nijmegen Holland
+31 243523100 GEN@SMITGAS.NL



REV	DATE	REVISED BY	CHK'D BY	COMMENTS

INSULATION BY SMIT GAS SYSTEMS

DELIVERY SMIT OR OPTIONAL

DELIVERY SHIPYARD

SEE TECHNICAL SPECIFICATION

FOR SYMBOLS ABBREVIATIONS + CONTROLS
SEE LIST: 65000A024R00

NOTE:

THE INTERCONNECTING PIPING BETWEEN WATER CHILLER UNIT AND INERTGAS COOLER SHOULD HAVE VENT VALVES AT HIGHEST POINT OF PIPING; FOR VENTING PURPOSES.

IT IS RECOMMENDED TO LAY INTERCONNECTING PIPING BETWEEN WATER CHILLER UNIT AND IG COOLER UNDER A CERTAIN SLOPE AS WELL.

AALBORG INDUSTRIES
AALBORG INDUSTRIES INERT GAS SYSTEMS BV

Nijmegen The Netherlands
+31 (0)24 3523100
email: gen@smitgas.nl
WWW.SMITGAS.COM

PROJECTION:

DRAWING TITLES:

SCHEMATIC DIAGRAM IG cooler

Smit Gas TM Gln 15000 - 0.25 BUFD

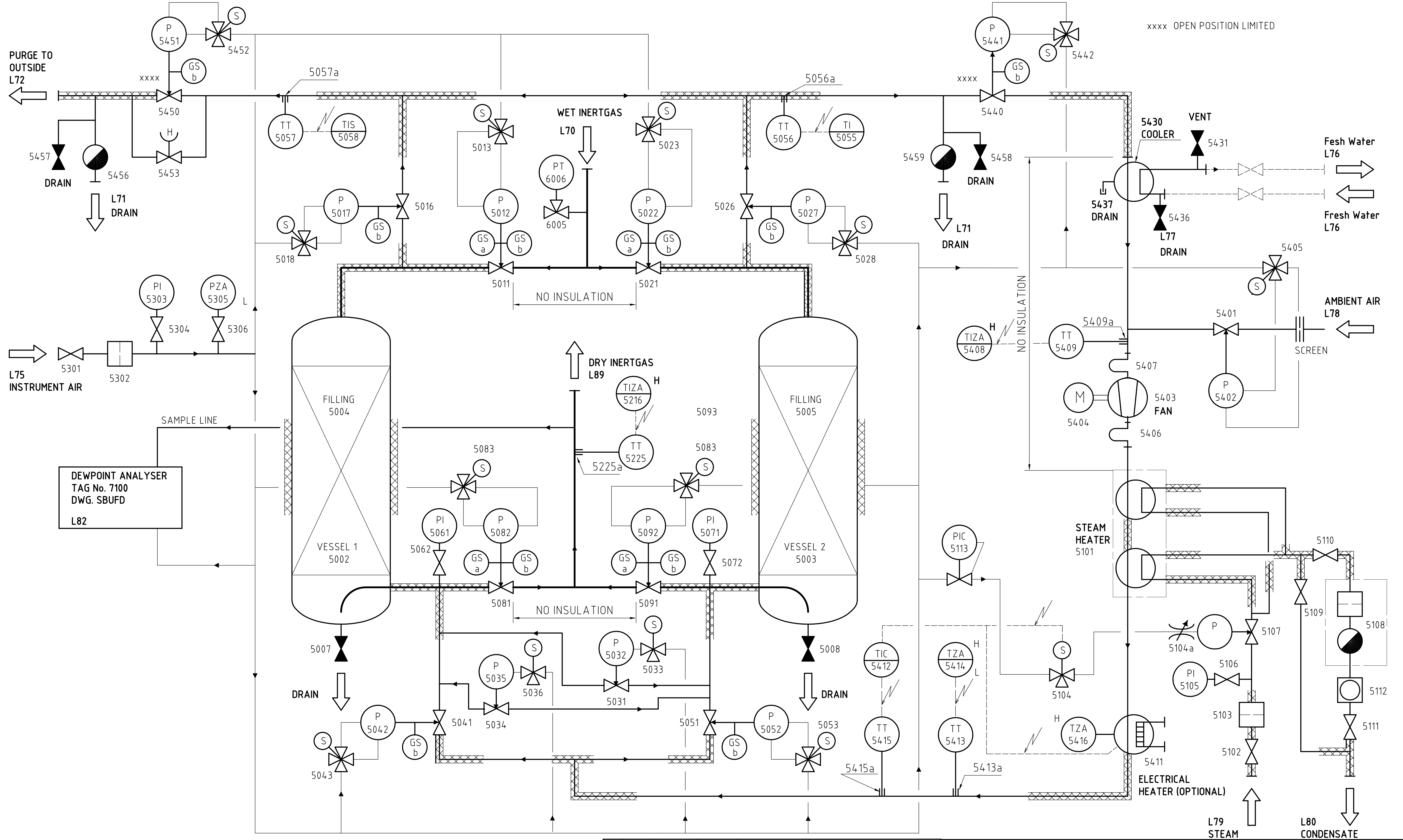
CLIENT REF.:
ORDER/PROJECT NO.:
REF. DWG.:

TOLERANCES UNLESS OTHERWISE SPECIFIED ACCORDING TO: EN ISO 13920-cf.

DRAWING No: 65225002

FORMAT: A2

DRAWN: JBE
DATE: 14-10-08
APPR.:
SCALE: N.A.
REV.: 00



INSULATION BY CUSTOMER

DELIVERY SMIT
DELIVERY SHIPYARD
} SEE TECHNICAL SPECIFICATION

FOR SYMBOLS ABBREVIATIONS + CONTROLS
SEE LIST: SSYMx005

REV	DATE	REVISED BY	CHK'D BY	COMMENTS

TOLERANCES UNLESS OTHERWISE SPECIFIED ACCORDING TO: ISO2768 - M

PROJECTION:

SMIT GAS SYSTEMS

Nijmegen Holland
+31 243523100 GEN@SMITGAS.NL

DWG. TITLE: SCHEMATIC DIAGRAM INERT GAS DRYER

CLIENT REF.:

ORDER/PROJECT NO.:

REF. DWG.: 19147

DWG. NO.: SBUFD0C3-1

FORMAT: A2

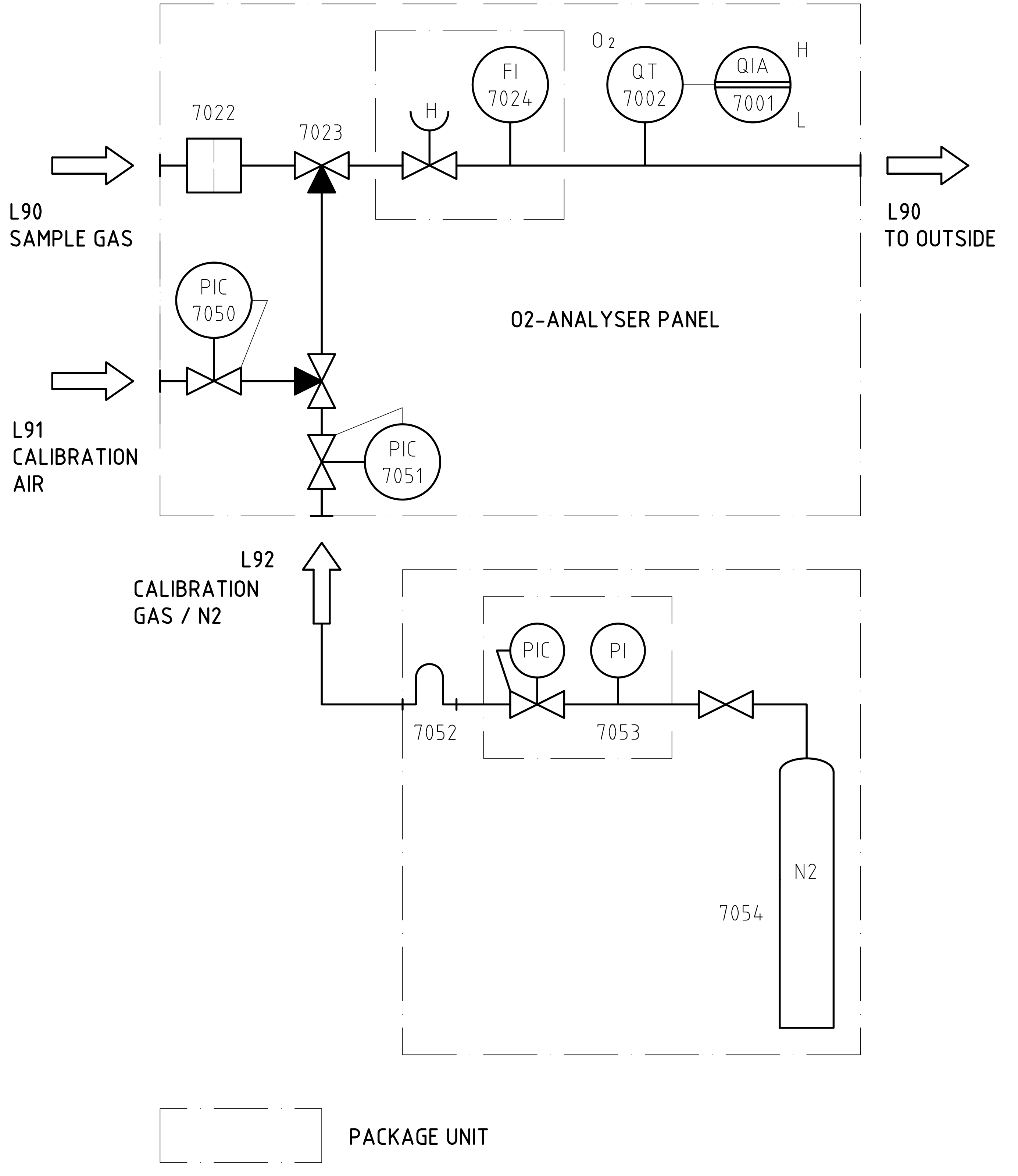
DATE: 06-11-2005

ORIG.: GLi

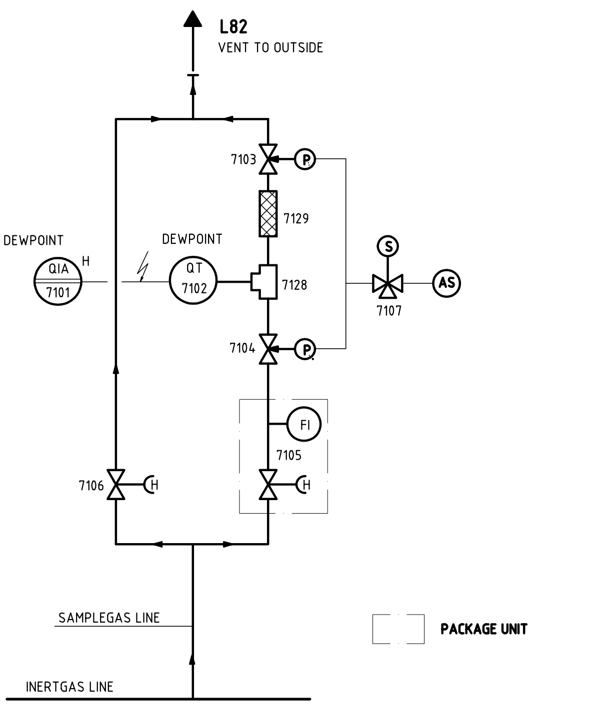
CHK'D:

SCALE: N.A.

REV.:

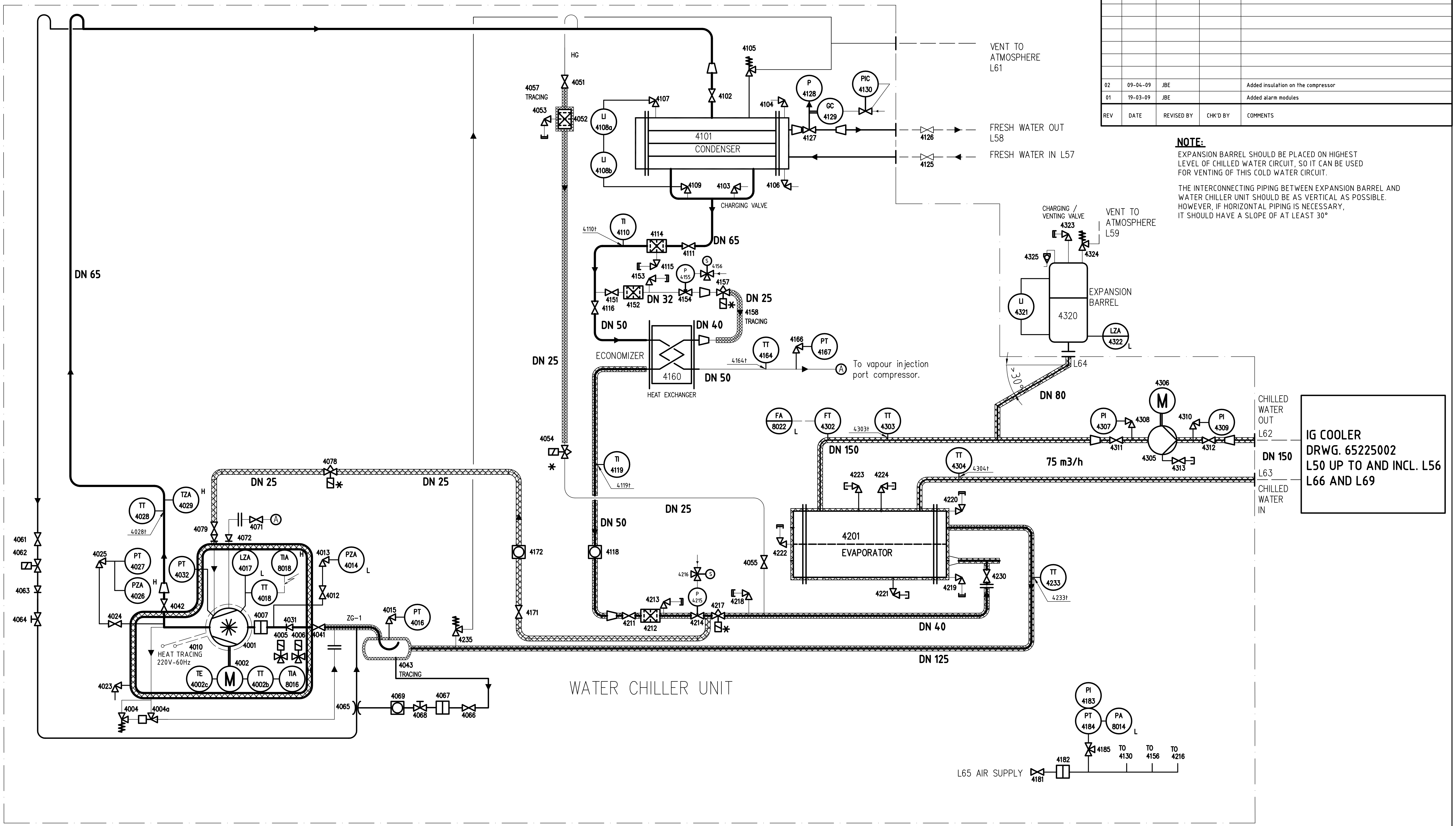


DWG. TITLE:	SCHEMATIC DIAGRAM O2-ANALYSER TAGNR.: 7000 TYPE BUFD
AutoCAD VERSION 13	
TOLERANCES UNLESS OTHERWISE SPECIFIED ACCORDING TO:	DIN 7168 - M
CLIENT REF.:	
DATE:	15-04-93
ORDER/PROJECT NO.:	STANDARD
ORIG.:	BORGONJEN
REF. DWG.:	4-12664
CHK'D:	
PROJECTION:	
SMIT GAS SYSTEMS	Nijmegen Holland
DWG. NO.:	SBUFD004
FORMAT:	A4
SCALE:	N.A.
REV.:	



DWG. TITLE: SCHEMATIC DIAGRAM DEWPOINT ANALYSER		
AutoCAD VERSION 13	TOLERANCES UNLESS OTHERWISE SPECIFIED ACCORDING TO: DIN 7168 - M	CLIENT REF.:
SMIT	PROJECTION:	ORDER/PROJECT NO.: STANDARD
		REF. DWG.: 4-12665
DATE: 15-04-93	ORIG.: BORGONJEN	CHK'D:
Nijmegen Holland	DWG. NO.: SBUFD005	FORMAT: A4
SCALE: N.A.	REV.:	

REV	DATE	REVISED BY	CHK'D BY	COMMENTS
02	09-04-09	JBE		Added insulation on the compressor
01	19-03-09	JBE		Added alarm modules



NOTE:
EXPANSION BARREL SHOULD BE PLACED ON HIGHEST LEVEL OF CHILLED WATER CIRCUIT, SO IT CAN BE USED FOR VENTING OF THIS COLD WATER CIRCUIT.

THE INTERCONNECTING PIPING BETWEEN EXPANSION BARREL AND WATER CHILLER UNIT SHOULD BE AS VERTICAL AS POSSIBLE. HOWEVER, IF HORIZONTAL PIPING IS NECESSARY, IT SHOULD HAVE A SLOPE OF AT LEAST 30°

NOTE:

* THE FILTER AT INLET OF EXPANSION VALVE ARE REMOVED OF THE VALVES WHICH ARE MARKED WITH A STAR

INSULATION BY AIIGS

DELIVERY SMIT OR OPTIONAL
DELIVERY SHIPYARD
} SEE TECHNICAL SPECIFICATION

FOR SYMBOLS ABBREVIATIONS + CONTROLS
SEE DWG : 65000A024R00

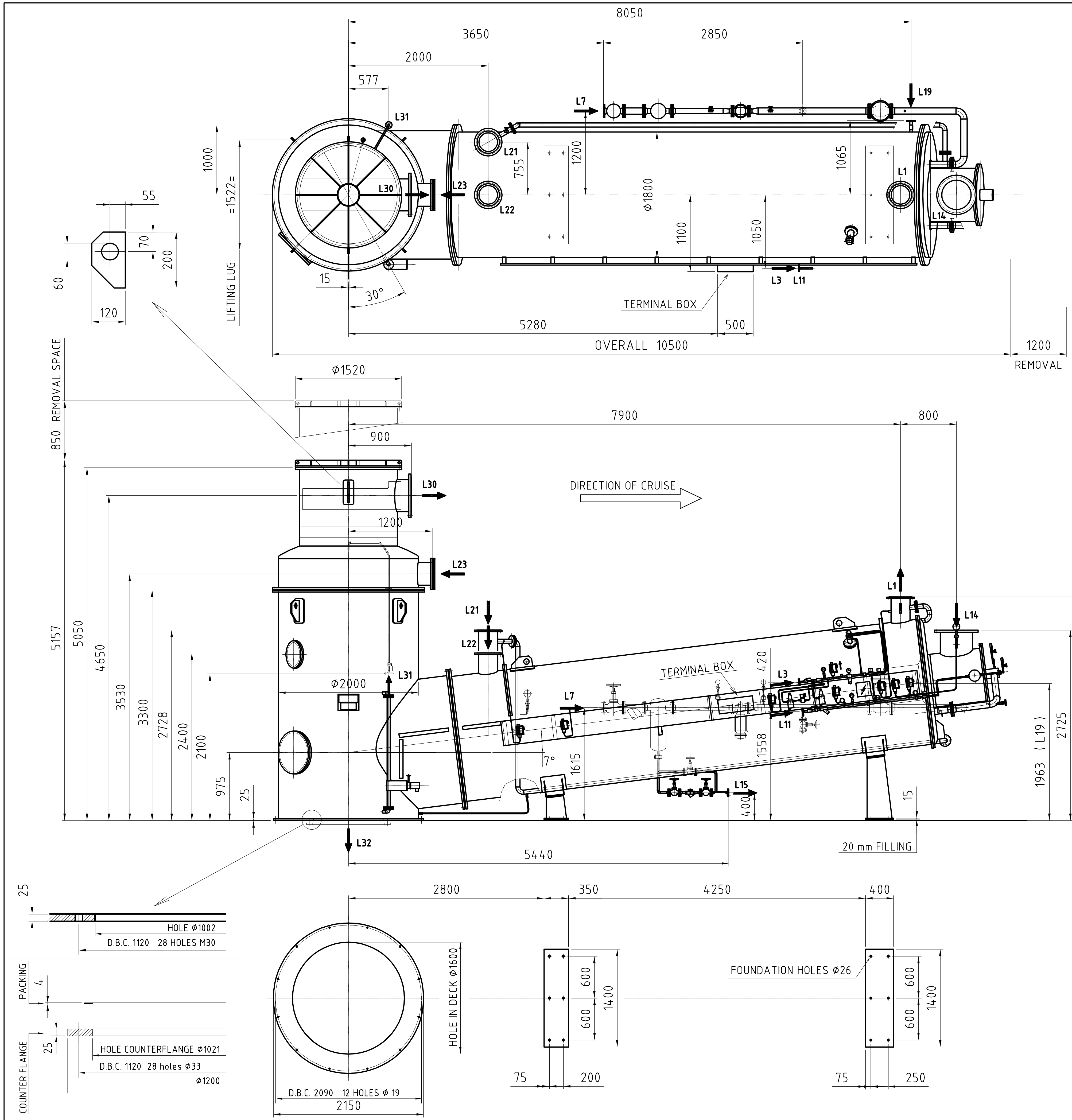
AALBORG INDUSTRIES
AALBORG INDUSTRIES INERT GAS SYSTEMS BV

PROJECTION:

Nijmegen The Netherlands
+31 (0)24 3523100
email: gen@smitgas.nl
WWW.SMITGAS.COM

DRAWING TITLES
SCHEMATIC DIAGRAM CHILLER UNIT
Smit Gas TM Gln 15000 - 0.25 BUFD R407c

CLIENT REF.:	DRAWN: JBE
ORDER/PROJECT NO.:	DATE: 10-11-08
REF. DWG.:	APPR.:
TOLERANCES UNLESS OTHERWISE SPECIFIED ACCORDING TO: EN ISO 13920-CF.	SCALE: N.A.
DRAWING No: 65095006	FORMAT: A2
	REV.: 02



REV	DATE	REVISED BY	CHK'D BY	COMMENTS

POSITION	DESCRIPTION	CONNECTION	
L1	COOLINGWATER	DN 250	DIN 2642
L3	INSTRUMENT AIR	DN 15	DIN 2633
L7	STEAM	DN 65	DIN 2635
L11	FUEL OIL	DN 20	DIN 2635
L14	COMBUSTION AIR	DN 500	DIN 2576
L15	CONDENSATE (steam)	DN 20	DIN 2635
L19	RINSINGWATER	DN 25	DIN 2642
L21	COOLINGWATER	DN 250	DIN 2642
L22	COOLINGWATER	DN 250	DIN 2642
L23	COOLING / WASHINGWATER	DN 300	DIN 2576
L30	INERTGAS	DN 500	DIN 2642
L31	RINSING WATER	DN 25	DIN 2642
L32	COOLINGWATER (to waterseal)	DN 1000	

NOTE: FOR TRANSPORT PARTS SEE DRAWING; 18530298

WEIGHT DRY: abt. 10700 kg.
WEIGHT WET: abt. 13500 kg.

DWG. TITLE: DIM.DRW. I.G. GENERATOR

TOLERANCES UNLESS OTHERWISE SPECIFIED ACCORDING TO: ISO2768 - M

PROJECTION:

CLIENT REF.:

ORDER/PROJECT NO.:

REF. DWG.: 18530299

DATE: 05-03-01

ORIG.: TBorgonjen

CHK'D:

SMIT GAS SYSTEMS

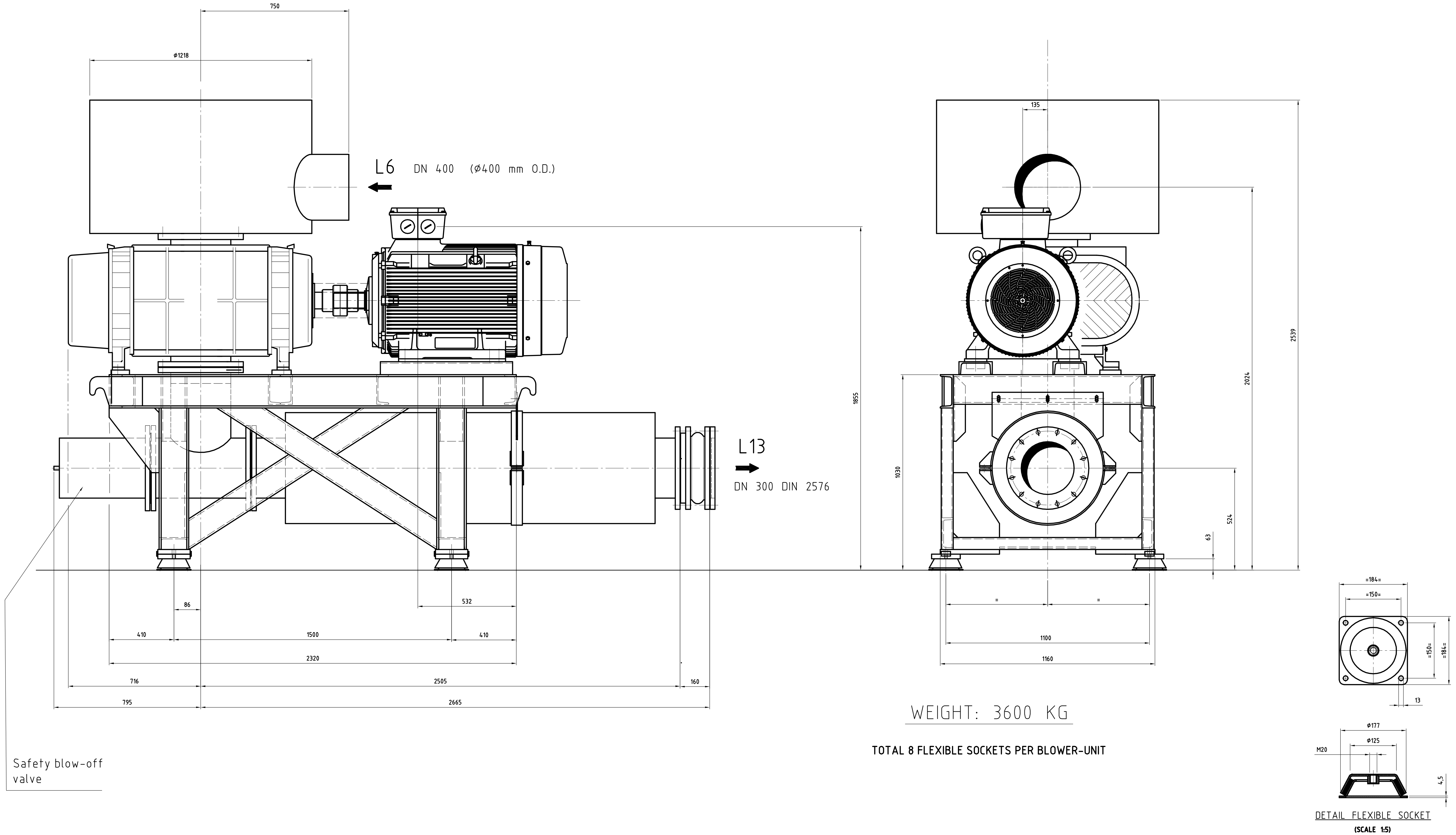
Nijmegen Holland
+31 243523100 GEN@SMITGAS.NL

DWG. NO.: P-G00002

FORMAT: A2

SCALE: 1:40

REV.:

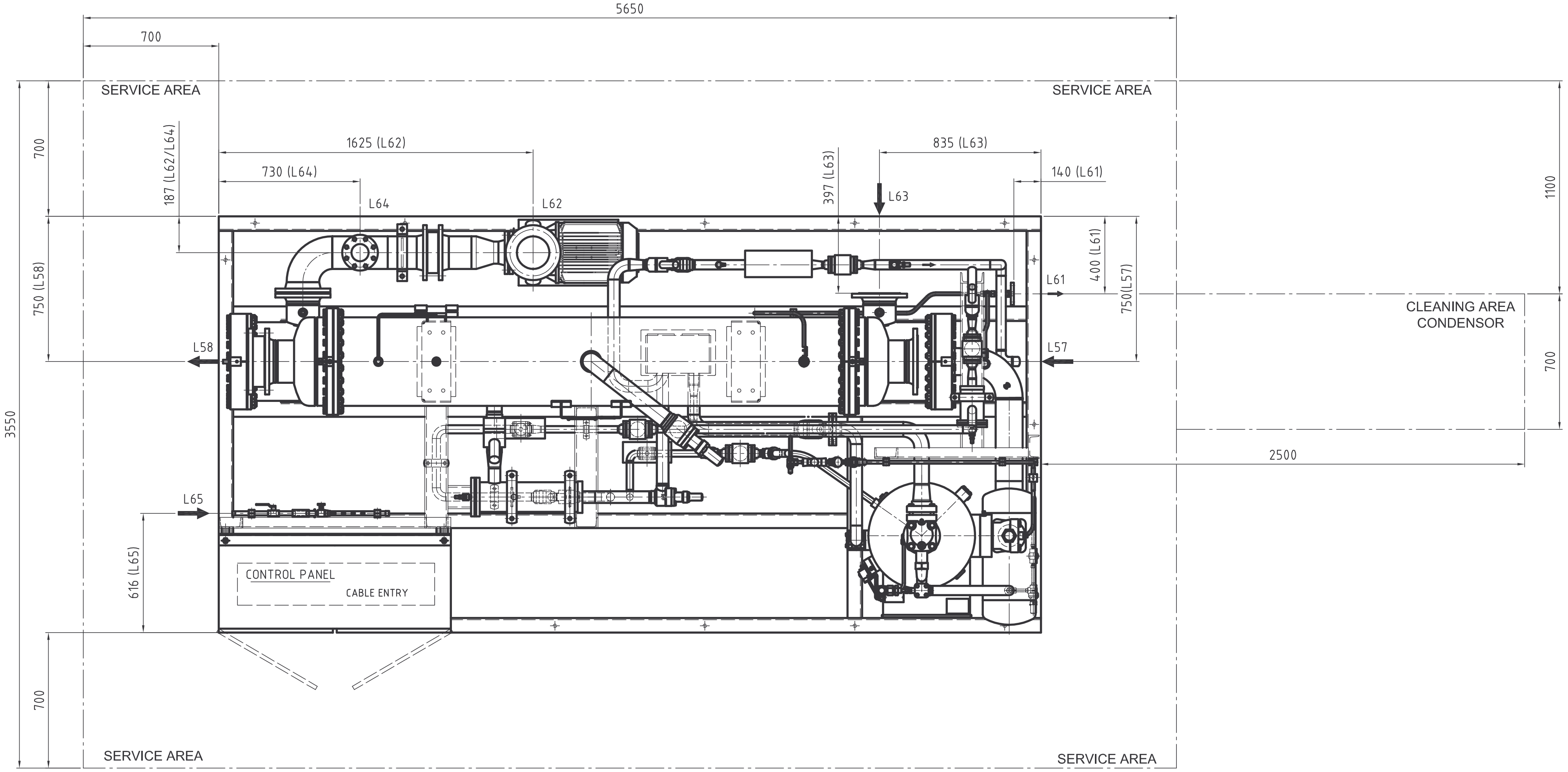


REV	DATE	REVISED BY	CHK'D BY	COMMENTS

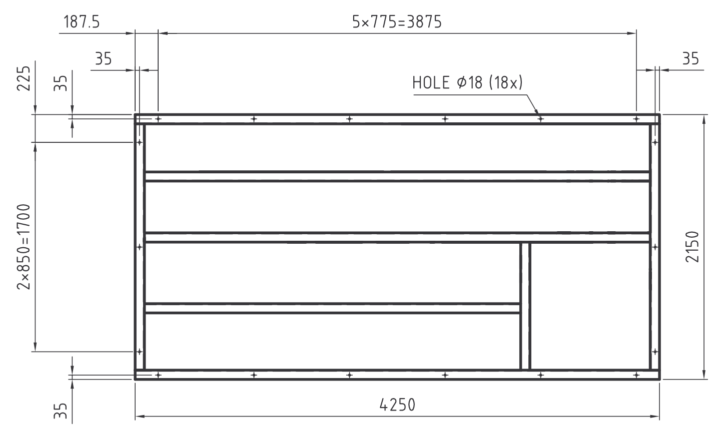
AutoCAD VERSION 13	TOLERANCES UNLESS OTHERWISE SPECIFIED ACCORDING TO: DIN 7168 - M
PROJECTION:	
SMIT GAS SYSTEMS	Nijmegen Holland
DWG. TITLE:	DIM. DRW. BLOWER UNIT TYPE: K 150 D-LP
CLIENT REF.:	
ORDER/PROJECT NO.:	
REF. DWG.:	18530309
DATE:	05-03-01
DRG:	TBorgonjen
CHK'D:	
DWG. NO.:	P-B00001
FORMAT:	A1
SCALE:	1:10
REV.:	1

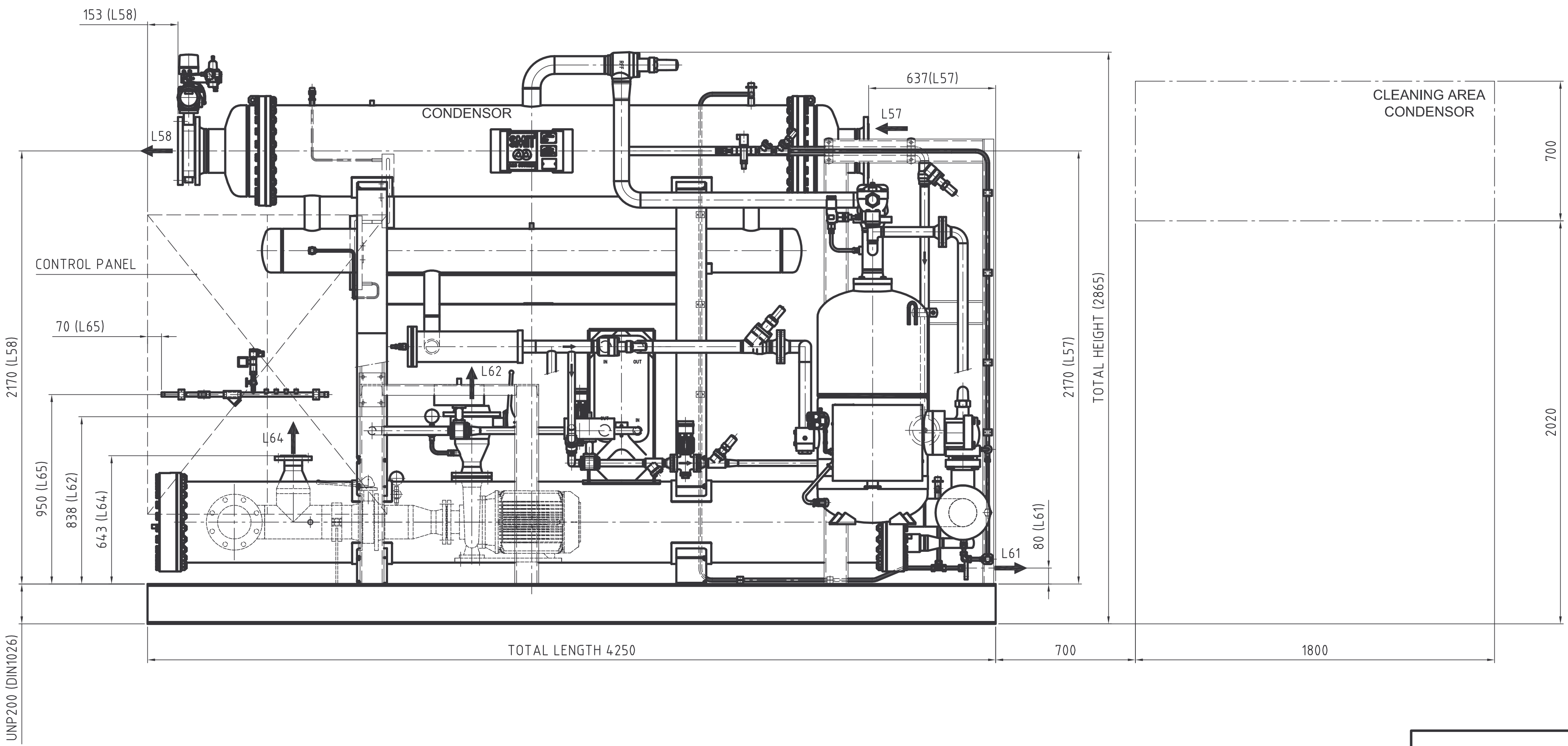
POSITION	DESCRIPTION	CONNECTION	
L57	COOLING WATER IN	DN 200	DIN 2632
L58	COOLING WATER OUT	DN 200	DIN 2576 ⊛
L61	VENT TO ATMOSPHERE	DN15	DIN 2576
L62	COOLING WATER OUT	DN 150	DIN 2632 ⊛
L63	COOLING WATER IN	DN 150	DIN 2632
L64	CONN. EXPANSION BARREL	DN 80	DIN 2642
L65	AIR SUPPLY	1/2" BSP MALE	

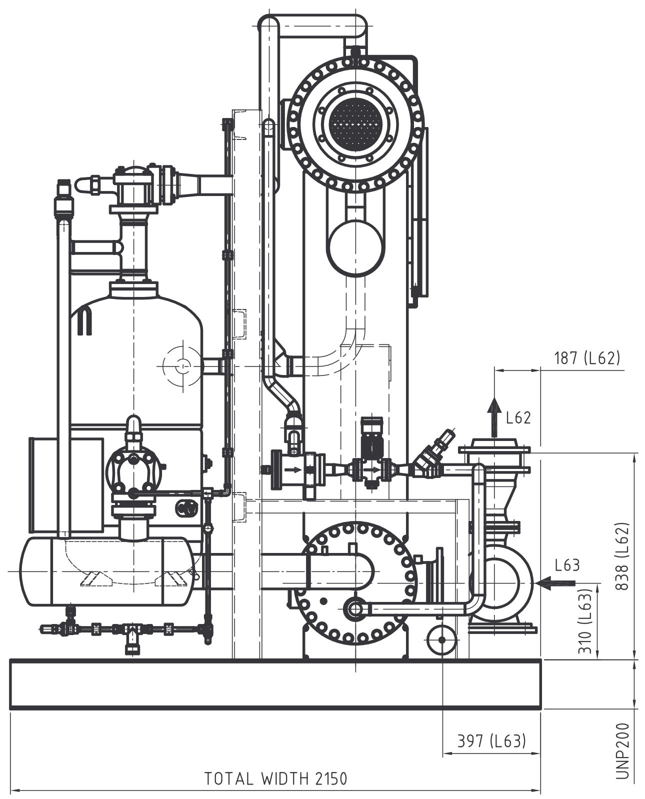
⊛ = INCL. COUNTERFLANGE



FOUNDATION PLAN
(1:30)



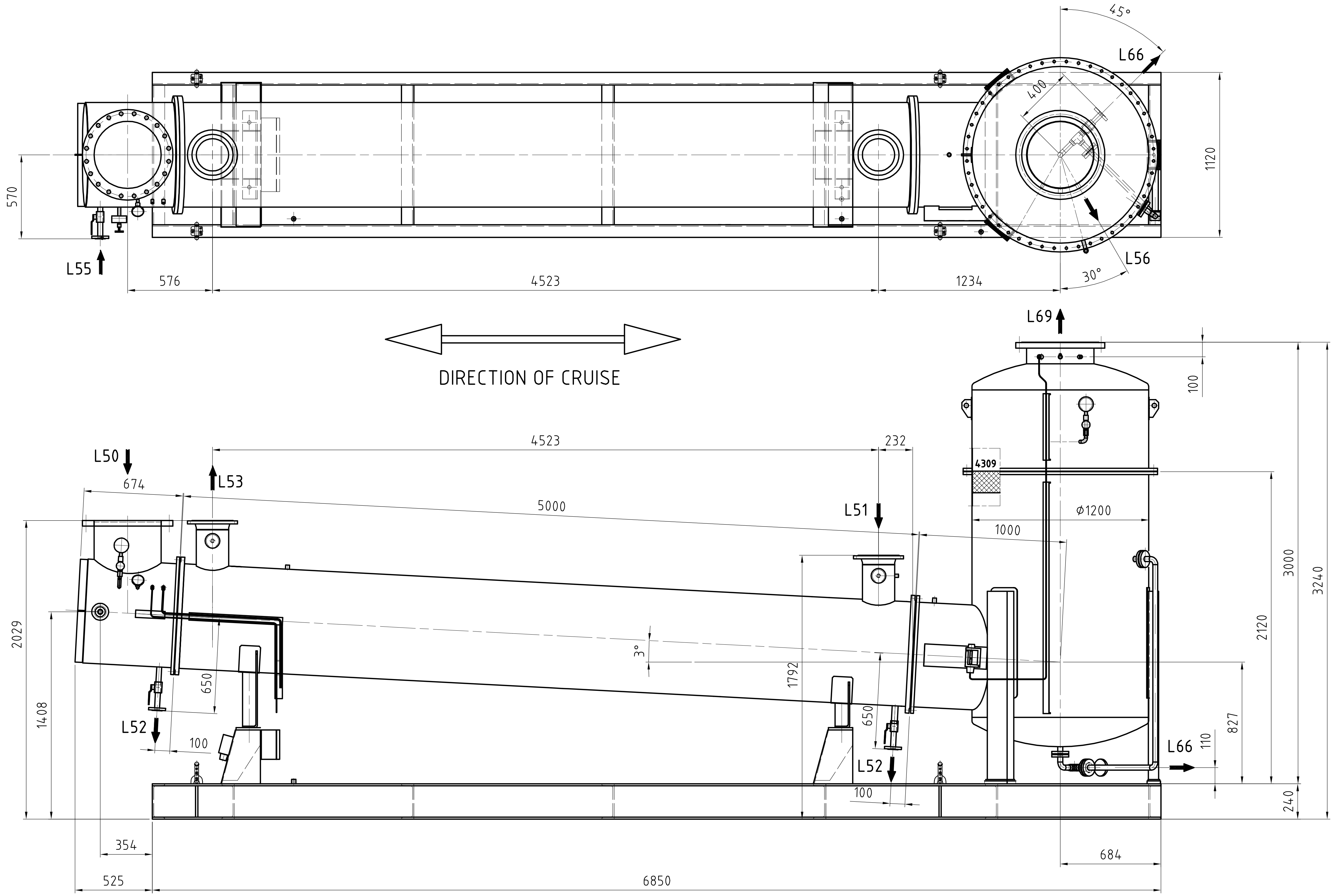




APPROX WEIGHT
DRY : APPROX. 4270 KG.
WET : APPROX. 4750 KG.

AALBORG INDUSTRIES AALBORG INDUSTRIES INERT GAS SYSTEMS BV	DRAWING TITLES CHILLER UNIT SKID		
PROJECTION: / Nijmegen The Netherlands +31 (0)24 3523100 email: gen@smitgas.nl WWW.SMITGAS.COM	CLIENT REF.:		DRAWN WHO
	ORDER/PROJECT NO.:		DATE: 02-10-2008
	REF. DWG.:		APPR. Mja
THIS DRAWING AND DESIGN SHOWN HEREIN IS THE PROPERTY OF AALBORG INDUSTRIES AND MUST NOT BE USED BY OR REPRODUCED FOR THIRD PARTY	TOLERANCES UNLESS OTHERWISE SPECIFIED ACCORDING TO: EN ISO 13920-CF.	DRAWING No 65095A424R01	FORMAT: A1
			SCALE: 1:15 REV.: 00

REV	DATE	REVISED BY	CHK'D BY	COMMENTS



POSITION	DESCRIPTION	CONNECTION
L50	INERTGAS INLET	DN 450 JIS (5 KG/CM²)
L51	CHILLED WATER	DN 125 DIN 2633 ⊛
L52 (2x)	DRAIN	DN 25 DIN 2642 ⊛
L53	CHILLED WATER	DN 125 DIN 2633 ⊛

POSITION	DESCRIPTION	CONNECTION
L55	RINSING WATER	DN 25 DIN 2642 ⊛
L56	SAMPLE GAS	1/4" BSP Female
L66	CONDENSATE	DN 25 DIN 2642 ⊛
L69	INERTGAS OUTLET	DN 450 JIS (5 KG/CM²)

⊛ INCL. COUNTERFLANGES

FOR FOUNDATION DIMENSIONS
SEE Drw. 19150420

WEIGHT DRY: abt. 4500kg.
WEIGHT WET: abt. 6000kg.

DWG. TITLE: Dim.Drw. INERTGAS COOLING UNIT

TOLERANCES UNLESS OTHERWISE SPECIFIED ACCORDING TO: EN ISO 13920-CE

PROJECTION

CLIENT REF.:

ORDER/PROJECT NO.:

REF. DWG.: 19251424

DATE: 10-01-06
ORIG.: JBE
CHK'D:

SMIT GAS SYSTEMS

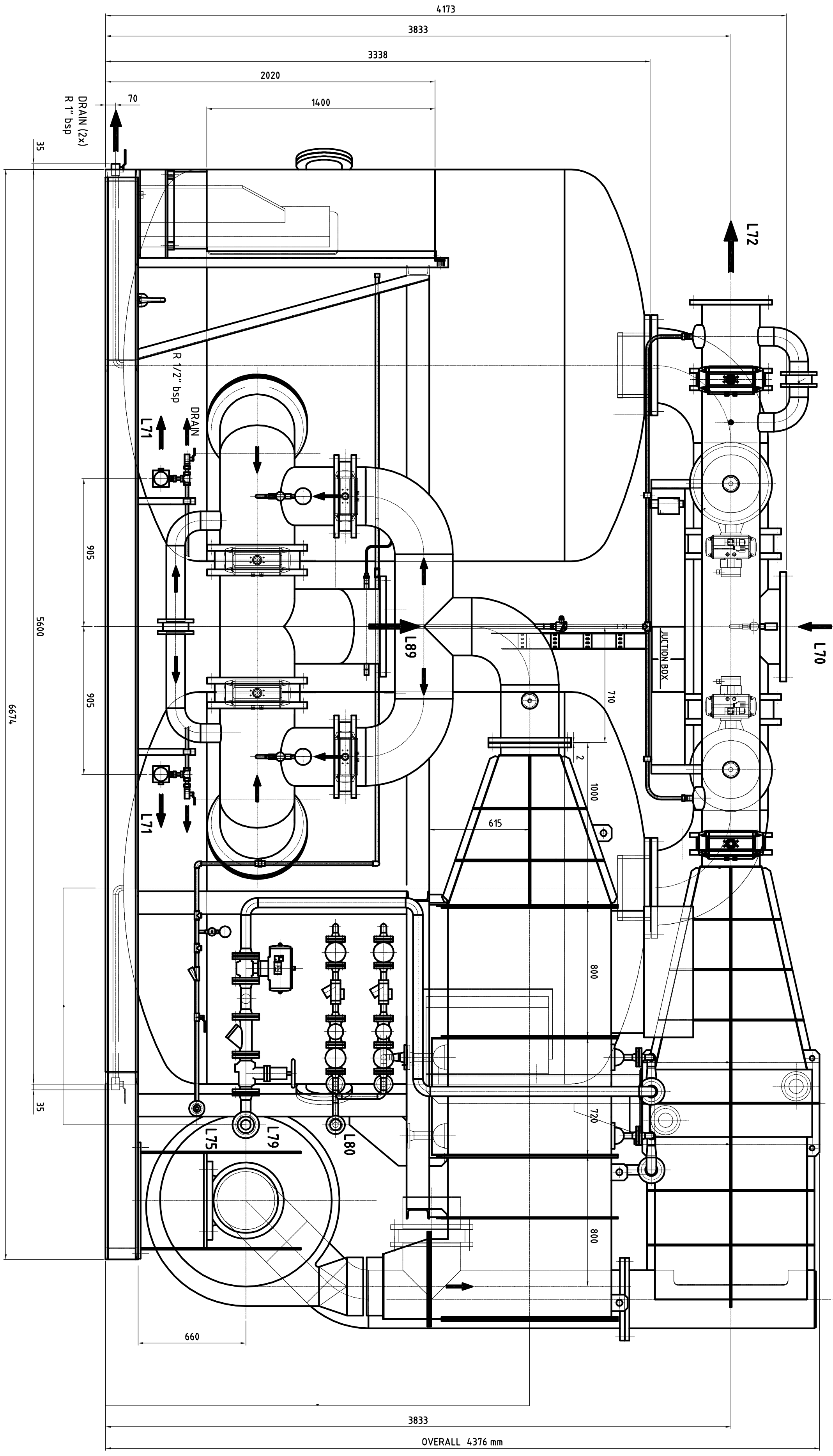
Nijmegen Holland
(+31) (0)243523100 GEN@SMITGAS.NL

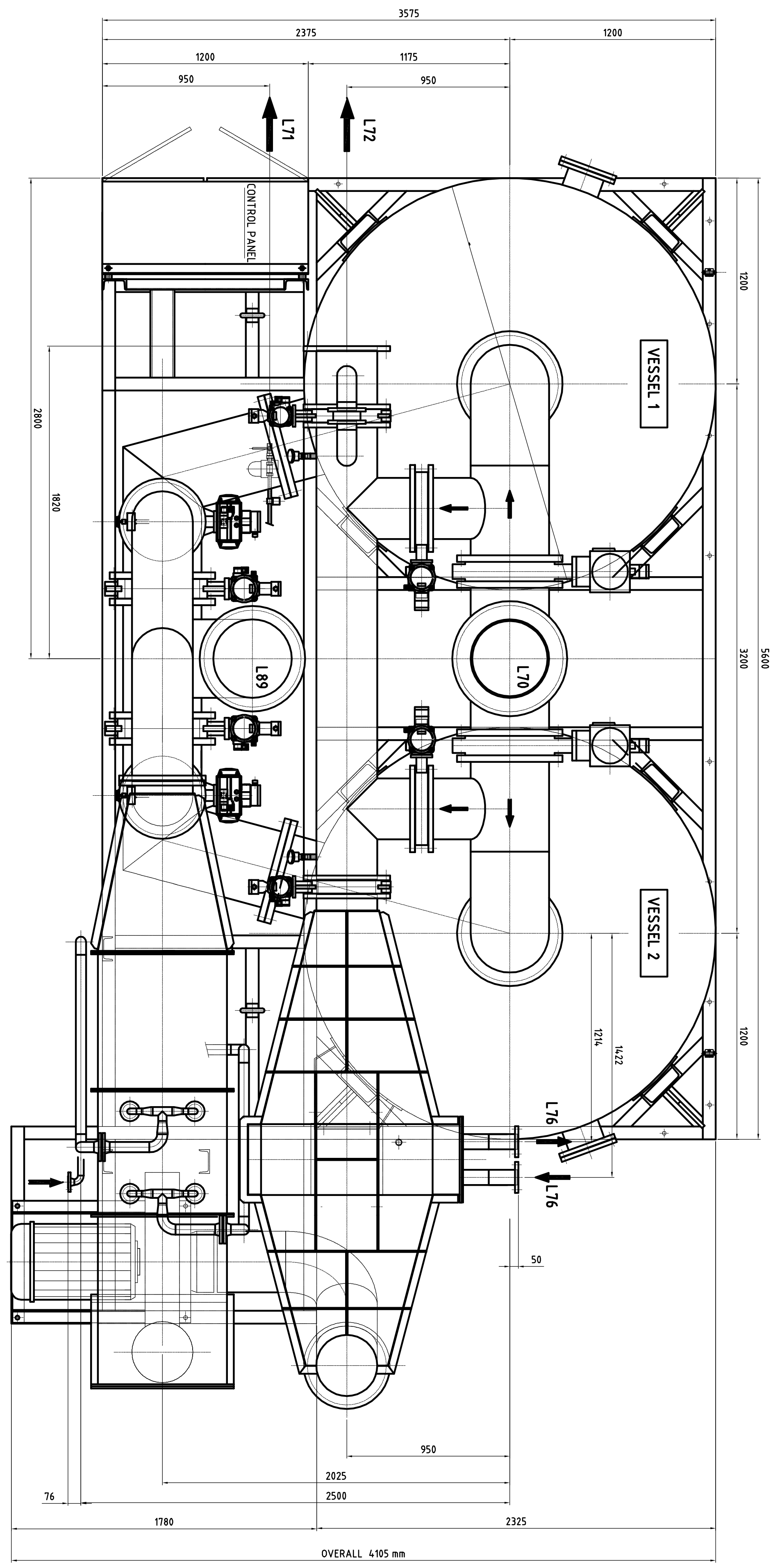
DWG. NO.: P-F00041

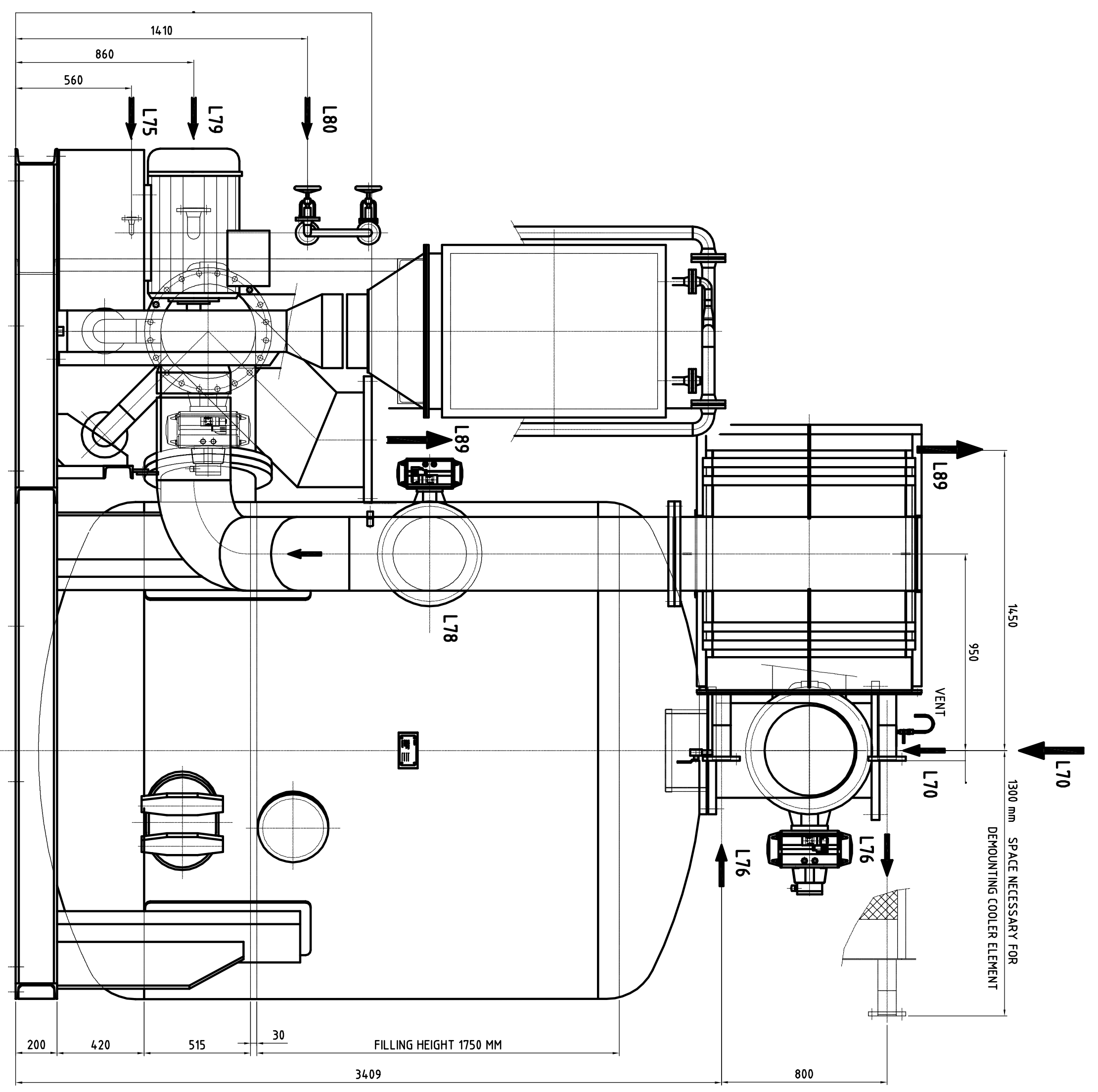
FORMAT: A2

SCALE: 1:20

REV.: 01







POSITION	DESCRIPTION	CONNECTION
L70	INERTGAS (WET)	DN 450 JIS 5K
L71	CONDESATE DRAIN (2x)	1/2" bsp female
L72	PURGE TO OUTSIDE	DN 350 JIS 5K
L73		
L74		
L75	INSTRUMENT AIR	DN 15 DIN 2633 ⊛
L76	FRESHWATER IN / OUT	DN 80 JIS 5K
L77	DRAIN	1/2" bsp female
L78	AMBIENT AIR	DN 350 Ø355,6 mm O.D
L79	STEAM	DN 50 DIN 2635 ⊛
L80	CONDENSATE	DN 25 DIN 2635 ⊛
L89	INERTGAS (DRY)	DN 450 JIS 5K

REV	DATE	REVISED BY	CHK'D BY	COMMENTS

TOTAL WEIGHT: appr. 26000 KG

FOR FOUNDATION PLAN SEE DRW. 19147372

⊛ INCL. COUNTER FLANGE

TOLERANCES UNLESS OTHERWISE SPECIFIED ACCORDING TO: EN ISO 13920-CF.

PROJECTION:

DWG. TITLE: DIM. DRW. INERTGAS DRYER Gin 15.000 – 0,25 BUFD

CLIENT REF.:

ORDER/PROJECT NO.:

REF. DWG.: 19150

DATE: 21-03-05

ORIG.: GvdL

CHK'D:

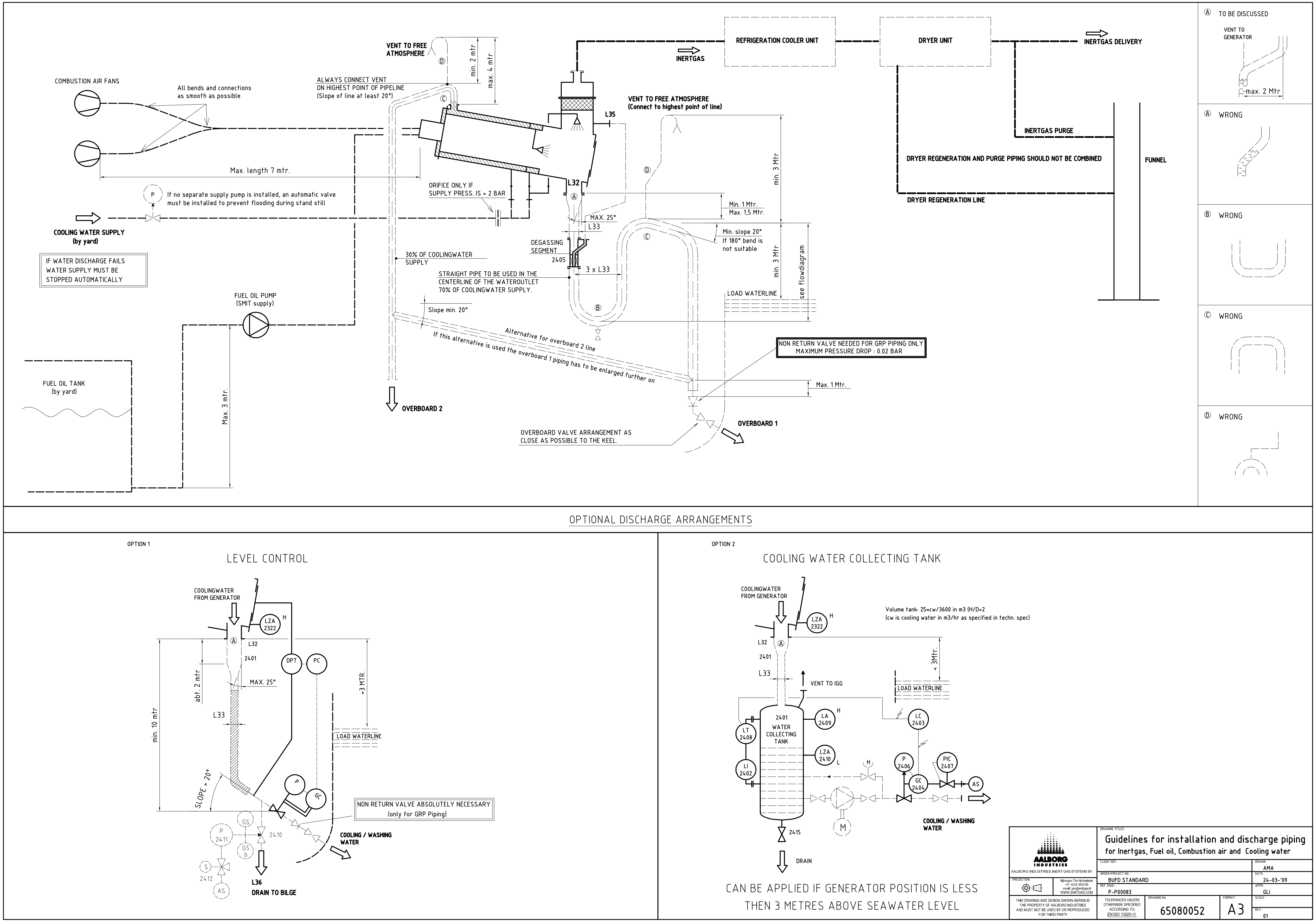
SCALE: 1:12.5

REV.:

DWG. NO.: P-D00024

FORMAT: A0

SMIT GAS SYSTEMS
Nijmegen Holland
(+31) (0)24 352 3100 GEN@SMITGAS.NL



AALBORG INDUSTRIES
AALBORG INDUSTRIES INERT GAS SYSTEMS BV
PROJECTION
Nijmegen The Netherlands
WWW.SMITGAS.COM
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DRAWING TITLE:
Guidelines for installation and discharge piping
for Inertgas, Fuel oil, Combustion air and Cooling water

CLIENT REF.:	
ORDER/PROJECT NO.:	BUFD STANDARD
REF. DWG.:	P-P00083
TOLERANCES UNLESS OTHERWISE SPECIFIED ACCORDING TO:	EN ISO 13920-CE
DRAWING No:	65080052
FORMAT:	A3
DRAWN:	AMA
DATE:	24-03-'09
APPR.:	GLI
SCALE:	
REV.:	01

MOUNTING INSTRUCTION FOR IG PLANT

Document number: 65080051
Rev:0
Date 22-02-2007

This document has the intention to avoid problems of wrong installation on board of the vessel resulting in wrong performance of the IG plant.

Each item on the following pages to indicate by ☑ to show “OK” or “not OK”
If “not OK” the remark line must be filled in. If not enough space for remark, please use last page.
If any of above installation instructions are not followed (or eventual deviations approved by AIIGS), the guarantee of the unit may not be valid any more.

This document to be returned signed by the yard to with the approval documents to Aalborg Industries.
If this document is not received signed before request for commissioning (2 weeks prior to commissioning) Aalborg Industries may not send an engineer for commissioning.

Customer:

Yard:	…
Department	…
Hull nr:	…
Date	…
Name of person in charge:	…
Signature:	…

Remarks (additional if needed):

Document number: 65080051
Rev:0
Date 22-02-2007

Mounting instructions Inert Gas

General:

- The process flow diagram as mentioned under chapter II.4 of the technical specification “diagrams” prevail at any time over other documents as mentioned under chapter II.4 of the technical specification “other documents”, in case of contradiction.

  OK ☐ not OK ☐
  Remark:

- The indication on the arrangement drawings concerning installation direction (longitudinal, direction of cruise, etc) must be followed.
  OK ☐ not OK ☐
  Remark:

- Space required for maintenance are indicated on the arrangement drawings and should be followed.
  OK ☐ not OK ☐
  Remark:

- Equipment installed on vibration dampers must have flexible pipe connections.
  OK ☐ not OK ☐
  Remark:

- The generator and blowers can be mounted directly on a flat floor
  OK ☐ not OK ☐
  Remark:

Fuel Oil Pump (FOP)

- FOP must can best be installed at level of fuel oil tank (because max

suction head of pump is only 4 mwc)
OK ☐ not OK ☐
Remark:

Blowers/Fans

- The blowers (roots type) to be arranged close to the generator, less than 20 metres.
  OK ☐ not OK ☐
  Remark:

- Fans (centrifugal type) be arranged close to the generator, less than 7 metres
  OK ☐ not OK ☐
  Remark:

- Interconnecting piping with few bends; pipe layout to be as symmetrical and aero dynamical as possible; the direction of the blower/fan shafts should be parallel to the centre line of the ship (because of gyroscopically effects)
  OK ☐ not OK ☐
  Remark:

Combustion chamber/burner

- For installation of the combustion chamber, special attention should be paid to the direction of installation. Standard (optimum) the unit should be installed in longitudinal direction of the ship with the burner forward, unless the arrangement drawing shows an alternative arrangement.
  OK ☐ not OK ☐
  Remark:

- The free contact for high water level must be connected by the yard to protect against flooding, if there is no electrical power on the unit (automatic interruption of cooling water supply to the unit is yard responsibility)
  OK ☐ not OK ☐
  Remark:

Inert gas refrigeration unit

- The foundation frame of the cooling unit must be fixed to the ship foundations at the indicated points to avoid high vibration levels.
  OK ☐ not OK ☐
  Remark:

- Never install ships cooling air outlet (for ventilation) directed to the refrigeration system. This can give temperature decrease of the unit resulting in low temperature shut downs.
  OK ☐ not OK ☐
  Remark:

- Never install vibration sensitive instrumentation to this unit
  OK ☐ not OK ☐
  Remark:

- Condensate drain lines and water lock to be installed below the drain connecting point at the cooler
  OK ☐ not OK ☐
  Remark:

Inert gas dryer unit

- Insulation of the dryer must be done according the indication on the PID's
  OK ☐ not OK ☐
  Remark:

- The purge of the dryer (L 75) should not be combined with other purge lines. This combination would influence the performance of the dryer.
  OK ☐ not OK ☐
  Remark:

- The max. allowable back pressure of L75 is 200 mmwc.
  OK ☐ not OK ☐
  Remark:

Sea water supply

- Additives are not allowed to be added to the seawater
  OK ☐ not OK ☐
  Remark:
- If not a dedicated cooling water pump is used for the cooling of the combustion chamber, an automatic sea water supply valve need to be installed at the inlet of the combustion chamber.
  OK ☐ not OK ☐
  Remark:

Sea water/ condensate discharge piping

- For the arrangement of inertgas generators water discharge systems on board ships, see example drawing in chapter II.4. (“other documents”: drawing 65070052. This can be used as guidelines only. Final agreement about application of such alternative must be made with approval by Aalborg Industries
  OK ☐ not OK ☐
  Remark:

- Effluent water seal to be mounted straight under generator/scrubber.

Never horizontal effluent piping should be used. If not only vertical pipes are used, these should have minimum slope 20. Any deviation should be send to Aalborg Industries for approval.
OK ☐ not OK ☐
Remark:

- For drains the indications on the process flow diagram must be followed in the first place followed secondary by the guidelines. The process flow diagram always prevails.
  OK ☐ not OK ☐
  Remark:

- All drain lines should be installed under a minimum slope of 20 degree.
  OK ☐ not OK ☐
  Remark:

Vents

- All vent lines indicated on the process flow diagrams should have a slope of at least 20 degree.
  OK ☐ not OK ☐
  Remark:

- If vents are combined, Aalborg Industries should be asked for approval. At least the size of the piping must be increased after joining of the pipes.
  OK ☐ not OK ☐
  Remark:

- The regeneration outlet from the dryer (L75) should not be combined with other vent/purge lines
  OK ☐ not OK ☐
  Remark:

Document number: 65080051
Rev:0
Date 22-02-2007

- All vents to be guided to outside (safety item as the vent may contain inert gas). Enough vent height over the deck to be taken care of for safety reasons

  OK ☐ not OK ☐
  Remark:

Document number: 65080051
Rev:0
Date 22-02-2007

IG Delivery line

- Non return valves used for ig (or air, seawater if applicable) will be of flap type and must be installed in piping longitudinal to the ship.
  OK ☐ not OK ☐
  Remark:

- For installation of the gas flow meter see drw P-P00332. Instruction for mounting must be followed depending the piping arrangement.
  OK ☐ not OK ☐
  Remark:

Electrical

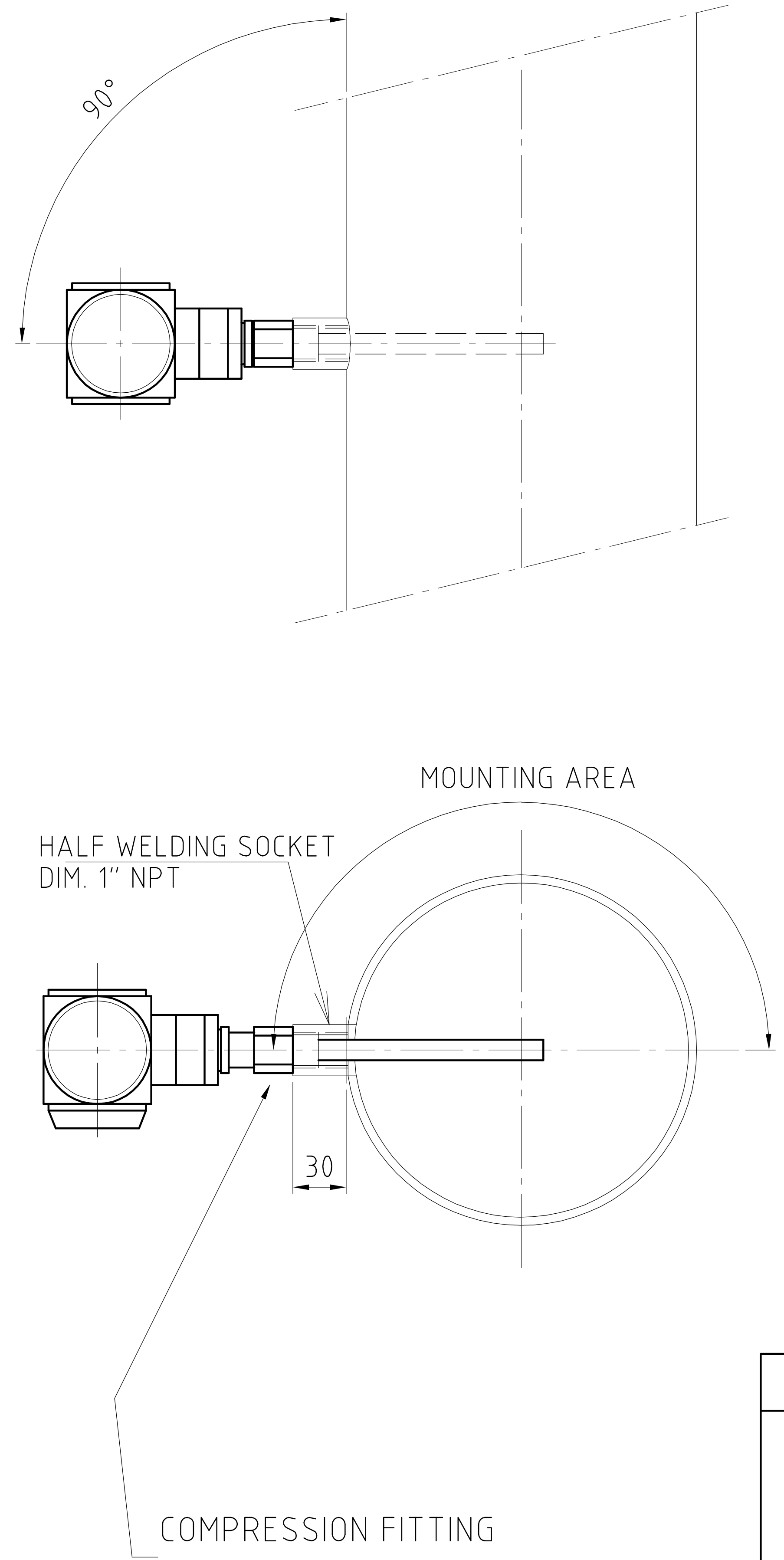
- The electric panels can be installed in any suitable place next to the unit. The arrangement has to be in such a way that the operator has a good view on the generator and the control panel.
  OK ☐ not OK ☐
  Remark:

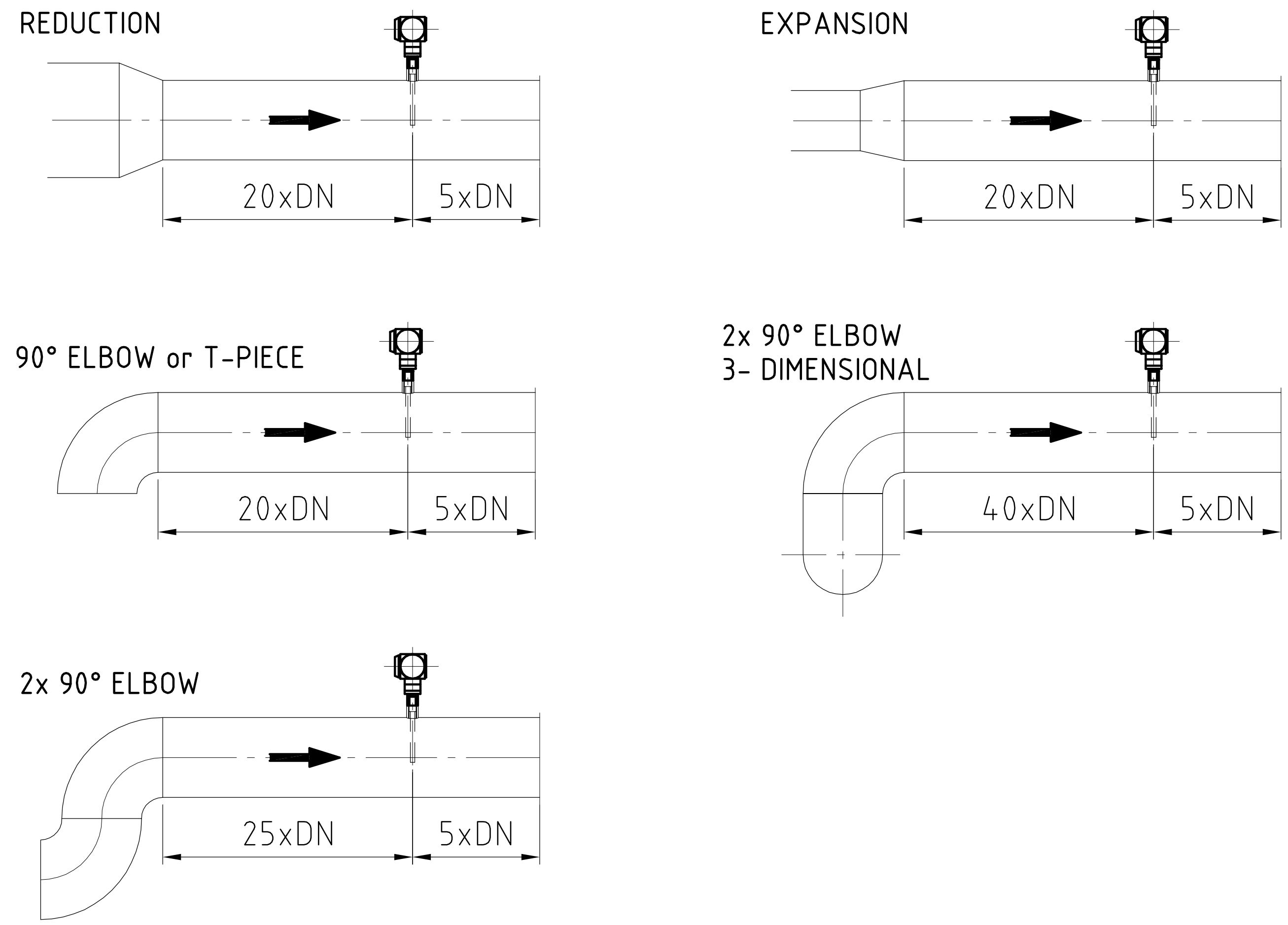
- The contact of the level switch of the scrubber should be connected by the ships control system to protect the IG plant against (not allowed) water supply when the control panels of the IG plant have no electric power on (see combustion chamber)
  OK ☐ not OK ☐
  Remark:

- All contacts that are mentioned in the electrical drawings as customer contact must be connected if indicated as such.
  OK ☐ not OK ☐
  Remark:

Remarks (additional if needed):

REV	DATE	REVISED BY	CHK'D BY	COMMENTS
01	13-07-07	SPE		Removed some dimensions





FLOW METER
SIZE : 1" NPT

PART No. 6065 schem.diagram

Enraf Smit Gas Systems

DWG. TITLE: FLOW TRANSMITTER arrangement

Nijmegen The Netherlands
tel.: +31 (0)24 3523100
email: gen@smitgas.nl

Visit us at:
www.smitgas.com

PROJECTION:

CLIENT REF.:

ORDER/PROJECT NO.:

REF. DWG.:

DATE: 15-09-2006

ORIG.: AMA

CHK'D:

TOLERANCES UNLESS OTHERWISE SPECIFIED ACCORDING TO: EN ISO 13920-CF.

DWG. NO.: P-P00332

FORMAT: A3

SCALE: 1:5

REV.: 01

VALVES

- CHECK VALVE
- BLOCK VALVE
- 3-WAY VALVE
- 4-WAY VALVE
- VALVE NORMALLY CLOSED
- VALVE NORMALLY OPEN
- REDUCING VALVE (PC)
- BACKPRESSURE REGULATOR (PC)
- PRESSURE SAFETY VALVE
- THROTTLE VALVE
- MECHANICAL LINKED VALVES
- PRESSURE CONTROL VALVE (PCV)

ACTUATORS

- PNEUMATIC OPERATED ACTUATOR (P)
- MOTOR OPERATED ACTUATOR (M)
- HAND OPERATED (H)
- SOLENOID OPERATED (S)

MISCELLANEOUS

- PARTICLE FILTER
- SILENCER
- WATER SEPERATOR
- LUBRICATOR
- SPRAYER NOZZLE
- SIGHT GLASS
- MECHANICAL CONDENSATE TRAP (208L)
- SPACE HEATER
- ELECTRICAL HEATER
- REDUCER
- FLEXIBLE HOSE
- SAMPLE POINT
- PLUG
- AIR SUPPLY FOR INSTRUMENT AIR (AS)
- ORIFICE
- MEMBRANE MODULE
- IGNITION TRANSFORMER
- VENT
- COOLER OR HEAT EXCHANGER
- COMPRESSOR, FAN OR BLOWER
- PUMP
- E-MOTOR (M)
- DEMISTER
- FILLING
- FLAME ARRESTOR
- DRAIN
- HORN

LINES

- MAIN FLOW LINE
- FLOW LINE
- UTILITY LINE
- CROSSING LINES
- INSULATED LINES AND /OR ELECTRICAL TRACING
- CONTROL LINES
- BLIND FLANGE
- ELECTRICAL WIRE / CABLE
- INPUT / OUTPUT LINES
- PACKAGED UNIT
- DELIVERY BY OTHERS

INSTRUMENTATION

- INSTRUMENT GENERAL LOCAL MOUNTED
- INSTRUMENT MOUNTED IN CONTROL PANEL
- 02 FIELD MOUNTED INSTRUMENT
- H HIGH / ALARM / L LOW
- GS a LIMIT SWITCH:
  a = OPEN POSITION
  b = CLOSED POSITION
  c = ANY POSITION

ELECTRICAL SYMBOLS

- (A) AMBER INDICATION LIGHT
- (B) BLUE INDICATION LIGHT
- (G) GREEN INDICATION LIGHT
- (R) RED INDICATION LIGHT
- (W) WHITE INDICATION LIGHT
- SWITCH
- INDICATOR
- PUSH BUTTON
- POTENTIAL FREE CONTACT

LETTER CODE FOR INSTRUMENTATION

	FIRST LETTER	SUCCEEDING LETTERS
A		ALARM
C		CONTROL
D		DIFFERENTIAL
F	FLOW	
G	POSITION	
H	HAND OPERATED	
I		INDICATING
L	LEVEL	
P	PRESSURE	
Q	ANALYSING	
R		RECORDING
S		SWITCHING
T	TEMPERATURE	TRANSMITTING
X	UNCLASSIFIED VARIABLE	
Z		EMERGENCY OF SAFETY ACTING

COMMONLY USED INSTRUMENTS

FI	FLOW INDICATOR	PZA	PRESSURE SWITCH WITH EMERGENCY OR SAFETY FUNTION
CV	CONTROL VALVE		
GS	LIMIT SWITCH	QC	QUALITY CONTROLLER
		QI	QUALITY INDICATOR
LI	LEVEL INDICATOR	QIA	QUALITY INDICATOR INCLUDING ALARMS
LS	LEVEL SWITCH		
LZA	LEVEL SWITCH WITH EMERGENCY OR SAFETY FUNCTION	QIR	QUALITY RECORDER
		TA	TEMPERATURE ALARM
		TC	THERMOSTAT
PI	PRESSURE INDICATOR	TI	THERMOMETER
PC	PRESSURE REGULATOR	TS	TEMPERATURE SWITCH
PDZA	DIFF. PRESSURE SWITCH WITH EMERGENCY OR SAFETY FUNCTION	TZA	TEMPERATURE SWITCH WITH EMERGENCY OR SAFETY FUNCTION
PIC	PRESSURE REGULATOR WITH INDICATOR	TT	TEMP. TRANSMITTER
PS	PRESSURE SWITCH	XZA	UV-DETECTOR WITH EMERGENCY OR SAFETY FUNCTION
PT	PRESSURE TRANSMITTER		

AALBORG INDUSTRIES
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PROJECTION
Nijmegen The Netherlands
+31 (0)24 3523100
email gen@smitgas.nl
WWW.SMITGAS.COM
DRAWING TITLE: SYMBOLS AND LETTER CODE FOR FLOW DIAGRAMS
CLIENT REF.: -
ORDER/PROJECT NO.: 0
REF. DWG.: SSYMX005_rev05
DRAWN: MSH
DATE: 02-03-2007
APPR.:
SCALE: n.a.
REV.: 06
TOLERANCES UNLESS OTHERWISE SPECIFIED ACCORDING TO: EN ISO 13920-
DRAWING No: SSYMx005
FORMAT: A3

SGT-400 Industrial Gas Turbine

Power Generation: (ISO) 12.90 MW(e)

The SGT-400 combines very high efficiency (nominal 35 %) with excellent emissions performance in a rugged industrial design. This makes it the ideal choice for a wide variety of power generation applications.

The Siemens twin-shaft industrial gas turbine SGT-400 features a compact gas generator and a two-stage power turbine, incorporating the latest aero-dynamic and combustion technologies. The turbine has a simple-cycle efficiency of nominally 35 %.

For industrial cogeneration, the high steam-raising capability of more than 27 tonnes per hour contributes towards achieving overall plant efficiencies of 80 % or higher. In addition, the compact arrangement, on-site maintainability and inherent reliability of the SGT-400 have made it an ideal gas turbine for the demanding oil and gas industry.

Incorporating proven gas turbine technology, the SGT-400 offers cost-effective power for a wide range of duties, including:

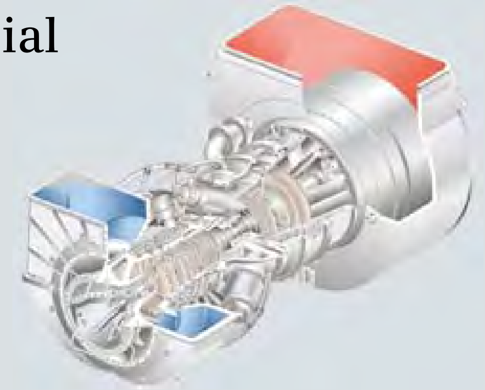
Industrial Power Generation

- Simple-cycle and combined-cycle power plants for base load, standby power and peak lopping
- Cogeneration for industrial plants with high heat load and district heating schemes

Power Generation in the Oil and Gas Industry

- Offshore: on oil platforms and FPSO (Floating Production, Storage & Offloading) vessels
- Onshore: for oil field service, refinery application, emergency and standby power generation,
- Including highly efficient cogeneration solutions for oil and gas applications

SGT-400 Industrial Gas Turbine



SGT-400 core engine test facility.

Technical specifications

Overview

- Twin-shaft, industrial
- Power generation: 12.90 MW(e)
- Frequency: 50 or 60 Hz
- Electrical efficiency: 34.8 %
- Heat rate: 10,355 kJ/kWh (9,815 Btu/kWh)
- Compressor pressure ratio: 16.8:1
- Exhaust gas flow: 39.4 kg/s (86.8 lb/s)
- Exhaust temperature: 555° C (1,031° F)
- Typical emissions: NO_x <15 ppmV and CO <10 ppmV (corrected to 15 % O_2 dry)
- Medium-calorific value fuels capability (>25 MJ/Nm³ Wobbe index)

Axial Compressor

- 11-stage with variable inlet guide vanes
- Air flow: (ISO) 38.9 kg/s
- Nominal speed: 14,100 rpm

Combustion

- 6 reverse-flow cannular combustion chambers
- Dry Low Emissions (DLE) system
- High-energy ignitor system

Turbine

- 2-stage overhung compressor turbine
  - Both stages are air-cooled
- 2-stage high-efficiency power turbine
  - Rotor blades have interlocking shrouds for mechanical integrity

Bearings

- Tilt-pad radial and thrust
- Standard vibration- and temperature-monitoring

Main reduction gearbox

- Speeds of 1,500rpm and 1,800rpm

Generator

- Voltages: 6 to 13.8 kV
- Frequency: 50 or 60 Hz

Package

- Fabricated steel underbase
  - Integral oil tank
  - Multi-point mounting
  - Optional 3-point mounting
- Modular fluid systems incorporating:
  - Lubricating oil system
  - Auxiliary gearbox-driven main pump
  - AC motor-driven auxiliary pump
  - DC motor-driven emergency pump
- Oil cooler and oil heater
- Electrically driven hydraulic start system
- Hydrocarbon drains tank on package
- Control system
  - Siemens SIMATIC PLC-based with distributed control and processing capability installed on package
  - Optional Allen-Bradley system
  - Optional off-package systems
- Vibration monitoring system
  - BN1701: Standard
  - BN3500: Optional
- Fire and gas detection equipment
- Fire suppression equipment
- On- and off-line compressor cleaning options available
- Combustion-air inlet-filtration options:
  - Simple static
  - Pulse cleaning
  - HEPA
- Enclosure
  - Painted carbon steel or stainless steel
  - Noise level options (85 dB(A) standard)

Gas turbine

Key features

- High simple-cycle and cogeneration efficiencies, cutting fuel costs
- Dual-fuel Dry Low Emissions (DLE) combustion system, meeting stringent legislation
- Twin-shaft arrangement for both power generation and mechanical drive, allowing commonality of parts in mixed duty installations

Maintenance

- Site maintainability or optional rapid core exchange as required by customer
- Designed for maintenance:
  - Horizontally split compressor casing
  - Horizontally and vertically split inlet casing
  - Combustion chambers, flame tubes and ignitors easily accessible for inspection
  - Large side-doors on enclosure for equipment change-out
  - Gas generator and power turbine removal on either side of package
- Multiple boroscope-inspection ports

SGT-400 package.

Sewage-sludge drying plant for the City of Athens, on Psyttalia island.

Package

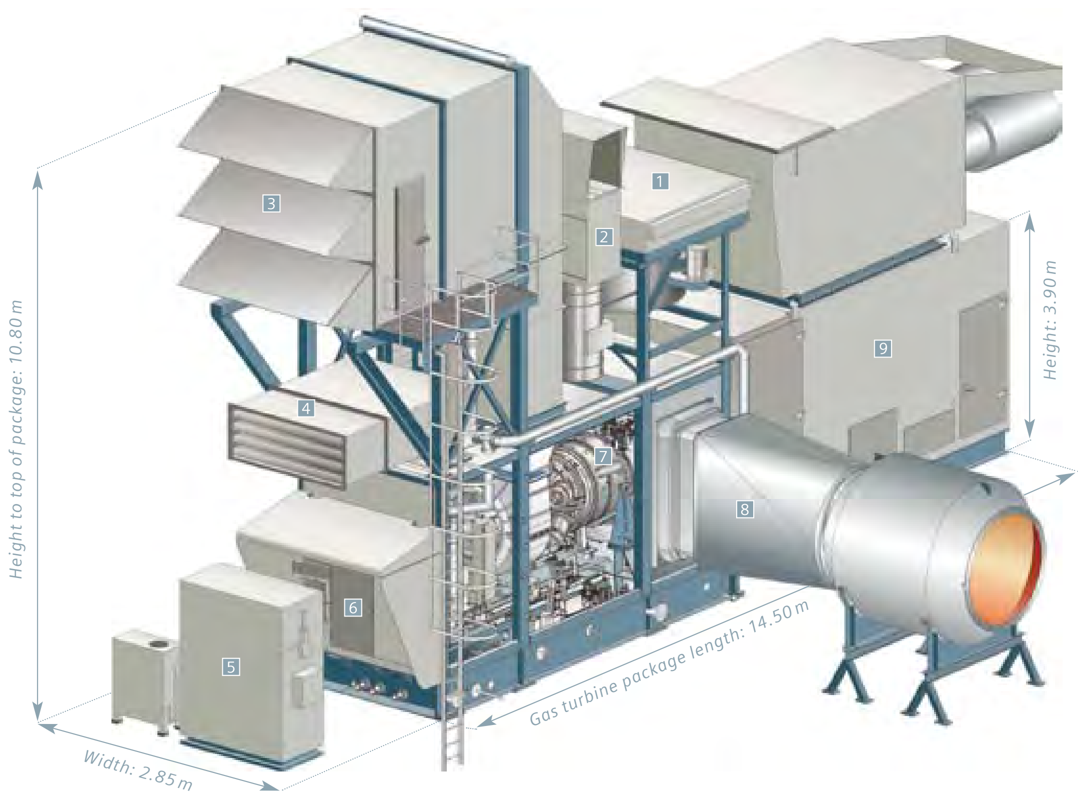
Key features

- Short installation time
- Compact package size, high power-to-weight ratio
- Factory testing:
  - Core engine
  - Functional testing of modules as standard
  - Pre-commissioning of package
  - Optional core customer-witness test
  - Optional complete package test
- Minimized customer interfaces

Customer Support

Key features

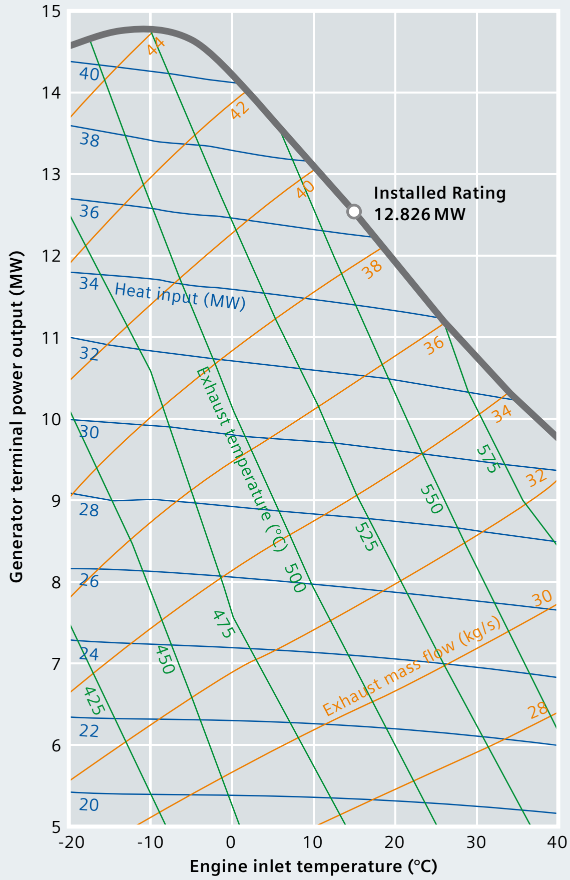
- Global support network of Authorized Service Centers
- Emergency service – 24/7 specialist helpdesk
- Full field service
- Full diagnostic support, remote monitoring
- OEM modernizations and upgrades
- In-house or on-site training programs
- Range of maintenance and service contracts available

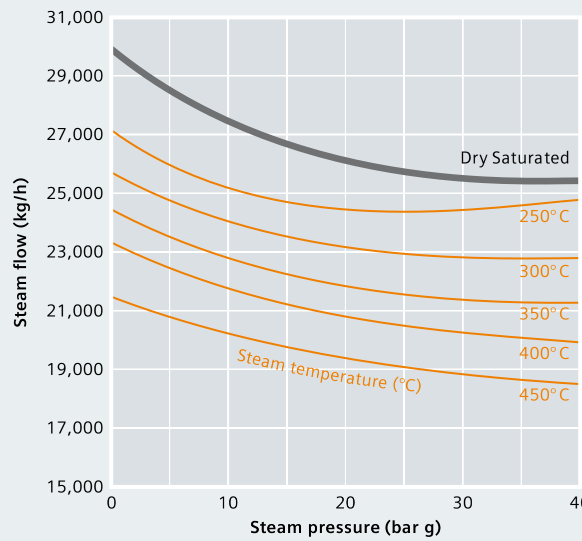


SGT-400 standard package

1 Lube oil cooler	4 Enclosure air inlet	7 Core engine
2 Enclosure air outlet	5 Fire and gas system	8 Combustion exhaust
3 Combustion air inlet	6 On-package controls	9 AC generator

SGT-400 Performance





Nominal generator output and heat rate

Conditions/assumptions:

Altitude:	Sea level	Natural gas fuel only.	
Ambient pressure:	101.3 kPa	Gearbox efficiency:	99.0 %
Inlet ducting loss:	1.0 kPa	Generator efficiency:	97.2 %
Exhaust ducting loss:	2.0 kPa	Relative humidity:	60 %
(assumes waste-heat recovery)		No CO-turndown bleed in operation	

***High ambient PT nozzle** – A high ambient temperature (30°C) rating is available to provide higher power at elevated site temperatures using an alternative power-turbine nozzle configuration.*

Unfired heat-recovery steam generation

Conditions/assumptions:

Exhaust gas mass flow:	39.5 kg/s
Gas temperature leaving boiler:	120°C
Assumed feed water temperature:	100°C
Exhaust gas temperature:	573°C

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Tel: +49 180 524 70 00
Fax: +49 180 524 24 71
(Charges depending on provider)
E-mail: support.energy@siemens.com

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DIESEL GENERATOR SET

Image shown may not reflect actual package.

STANDBY

3000 ekW 3750 kVA
60 Hz 1800 rpm 12 470 Volts

Caterpillar is leading the power generation marketplace with Power Solutions engineered to deliver unmatched flexibility, expandability, reliability, and cost-effectiveness.

FEATURES

FUEL/EMISSIONS STRATEGY
- EPA Certified for Stationary Emergency Application (EPA Tier 2 emissions levels)

DESIGN CRITERIA
- The generator set accepts 100% rated load in one step per NFPA 110 and meets ISO 8528-5 transient response.

FULL RANGE OF ATTACHMENTS
- Wide range of bolt-on system expansion attachments, factory designed and tested
- Flexible packaging options for easy and cost effective installation

SINGLE-SOURCE SUPPLIER
- Fully prototype tested with certified torsional vibration analysis available

WORLDWIDE PRODUCT SUPPORT
- Cat dealers provide extensive post sale support including maintenance and repair agreements
- Cat dealers have over 1,800 dealer branch stores operating in 200 countries
- The Cat® S•O•S℠ program cost effectively detects internal engine component condition, even the presence of unwanted fluids and combustion by-products

CAT® C175-16 DIESEL ENGINE
- Reliable and durable
- Four-stroke diesel engine combines superior performance with excellent fuel economy
- Advanced electronic engine control
- Low installation and operating cost

CAT GENERATOR
- Matched to the performance and output characteristics of Cat engines
- Industry leading mechanical and electrical design
- Industry leading motor starting capabilities
- High Efficiency

CAT EMCP 4 CONTROL PANELS
- Simple user friendly interface and navigation
- Scalable system to meet a wide range of customer needs
- Integrated Control System and Communications Gateway

SEISMIC CERTIFICATION
- Seismic Certification available
- Anchoring details are site specific, and are dependent on many factors such as generator set size, weight, and concrete strength.
  IBC Certification requires that the anchoring system used is reviewed and approved by a Professional Engineer
- Seismic Certification per Applicable Building Codes: IBC 2000, IBC 2003, IBC 2006, IBC 2009, CBC 2007
- Pre-approved by OSHP and carries an OPA#(OSP-0084-01) for use in healthcare projects in California

CAT®

FACTORY INSTALLED STANDARD & OPTIONAL EQUIPMENT

System	Standard	Optional
Air Inlet	• Air cleaner, 4 x single element canister with service indicator(s) • Plug group for air inlet shut-off	[ ] Air cleaner, 4 x dual element with service indicator(s) [ ] Air inlet adapters
Circuit Breakers		(No set mounted circuit breakers available on medium or high voltage packages)
Cooling	• SCAC cooling • Jacket water and AC inlet/outlet flanges	[ ] Package mounted vertical SCAC radiator [ ] Remote horizontal SCAC radiator [ ] Remote fuel cooler
Crankcase Systems	• Open crankcase ventilation	[ ] Crankcase explosion relief valve
Exhaust	• Dry exhaust manifold • Bolted flange (ANSI 6" & DIN 150) with bellow for each turbo (qty 4)	[ ] Engine Exhaust Temperature Module [ ] Mufflers (15 dBA,25 dBA, or 40 dBA) [ ] Dual 16" or single 20" vertical exhaust collector [ ] Weld flange ANSI 20"
Fuel	• Primary fuel filter with water separator • Secondary fuel filters (engine mounted)	
Generator	• 3 phase brushless, salient pole • IEC platinum stator RTD's • Cat digital voltage regulator (CDVR)	[ ] Space heater [ ] Oversize generators [ ] Power connection arrangement
Governor	• ADEM™ A4	[ ] Redundant shutdown
Control Panels	• EMCP 4	[ ] Local & remote annunciator modules [ ] Digital I/O module [ ] Generator temperature monitoring & protection [ ] Remote monitoring software [ ] Load share module
Lube	• Lubricating oil • Oil filter, filler and dipstick • Oil drain line with valves • Fumes disposal • Electric prelube pumps • Integral lube oil cooler	
Mounting	• Rails-engine / generator • Rubber anti-vibration mounts (shipped loose)	[ ] Spring type linear vibration isolator [ ] IBC vibration isolators
Starting/Charging	• Dual 24 volt electric starting motors • Batteries with rack and cables • Battery disconnect switch	[ ] Oversize batteries [ ] 75 amp charging alternator [ ] Battery chargers (20,35 or 50 Amp) [ ] Jacket water heater [ ] Redundant Electric Starter
General	• RH service (Except LH Service Oil Filter) • Paint - Caterpillar Yellow with high gloss black rails • SAE standard rotation • Flywheel and flywheel housing - SAE No. 00	[ ] Barring group- manual or air powered [ ] Factory test reports

SPECIFICATIONS

CAT GENERATOR

Frame size.. 3020
Excitation... Permanent Magnet
Pitch.. 0.6667
Number of poles.. 4
Number of bearings... 2
Number of Leads... 006
Insulation....................... UL 1446 Recognized Class H with tropicalization and antiabrasion
- Consult your Caterpillar dealer for available voltages
IP Rating... IP23
Alignment... Closed Coupled
Overspeed capability... 150
Wave form Deviation (Line to Line)............................... 5%
Voltage regulator.............. 3 Phase sensing with selectible volts/Hz
Voltage regulation............Less than +/- 1/2% (steady state)
Less than +/- 1/2% (with 3% speed change)

CAT DIESEL ENGINE

C175 SCAC, V-16, 4-Stroke Water-cooled Diesel
Bore... 175.00 mm (6.89 in)
Stroke.. 220.00 mm (8.66 in)
Displacement.. 84.67 L (5166.88 in^3)
Compression Ratio... 15.3:1
Aspiration.. Turbo Aftercooled
Fuel System.. Common Rail
Governor Type.. ADEM™ A4

CAT EMCP 4 SERIES CONTROLS

EMCP 4 controls including:
- Run / Auto / Stop Control
- Speed and Voltage Adjust
- Engine Cycle Crank
- 24-volt DC operation
- Environmental sealed front face
- Text alarm/event descriptions

Digital indication for:
- RPM
- DC volts
- Operating hours
- Oil pressure (psi, kPa or bar)
- Coolant temperature
- Volts (L-L & L-N), frequency (Hz)
- Amps (per phase & average)
- ekW, kVA, kVAR, kW-hr, %kW, PF

Warning/shutdown with common LED indication of:
- Low oil pressure
- High coolant temperature
- Overspeed
- Emergency stop
- Failure to start (overcrank)
- Low coolant temperature
- Low coolant level

Programmable protective relaying functions:
- Generator phase sequence
- Over/Under voltage (27/59)
- Over/Under Frequency (81 o/u)
- Reverse Power (kW) (32)
- Reverse reactive power (kVAr) (32RV)
- Overcurrent (50/51)

Communications:
- Six digital inputs (4.2 only)
- Four relay outputs (Form A)
- Two relay outputs (Form C)
- Two digital outputs
- Customer data link (Modbus RTU)
- Accessory module data link
- Serial annunciator module data link
- Emergency stop pushbutton

Compatible with the following:
- Digital I/O module
- Local Annunciator
- Remote CAN annunciator
- Remote serial annunciator

STANDBY 3000 ekW 3750 kVA

60 Hz 1800 rpm 12 470 Volts

TECHNICAL DATA

Open Generator Set - - 1800 rpm/60 Hz/12 470 Volts	DM8448	
EPA Certified for Stationary Emergency Application (EPA Tier 2 emissions levels)		
Generator Set Package Performance		
Genset Power rating @ 0.8 pf	3750 kVA	
Genset Power rating with fan	3000 ekW	
Fuel Consumption		
100% load with fan	810.7 L/hr	214.2 Gal/hr
75% load with fan	625.8 L/hr	165.3 Gal/hr
50% load with fan	493.6 L/hr	130.4 Gal/hr
Cooling System[1]		
Air flow restriction (system)	0.12 kPa	0.48 in. water
Engine coolant capacity	303.5 L	80.2 gal
Inlet Air		
Combustion air inlet flow rate	276.7 m^3/min	9771.6 cfm
Exhaust System		
Exhaust stack gas temperature	477.7 ° C	891.9 ° F
Exhaust gas flow rate	725.6 m^3/min	25624.3 cfm
Exhaust flange size (internal diameter)	150 mm	6 in
Exhaust system backpressure (maximum allowable)	6.7 kPa	26.9 in. water
Heat Rejection		
Heat rejection to coolant (total)	1379 kW	78424 Btu/min
Heat rejection to exhaust (total)	3149 kW	179083 Btu/min
Heat rejection to atmosphere from engine	147 kW	8360 Btu/min
Heat rejection to atmosphere from generator	178.0 kW	10122.8 Btu/min
Alternator[2]		
Motor starting capability @ 30% voltage dip	7879 skVA	
Frame	3020	
Temperature Rise	130 ° C	234 ° F
Emissions (Nominal)[3]		
NOx g/hp-hr	6.07 g/hp-hr	
CO g/hp-hr	.73 g/hp-hr	
HC g/hp-hr	.11 g/hp-hr	
PM g/hp-hr	.034 g/hp-hr	

[1] For ambient and altitude capabilities consult your Cat dealer. Air flow restriction (system) is added to existing restriction from factory.
[2] UL 2200 Listed packages may have oversized generators with a different temperature rise and motor starting characteristics. Generator temperature rise is based on a 40 degree C ambient per NEMA MG1-32.
[3] Emissions data measurement procedures are consistent with those described in EPA CFR 40 Part 89, Subpart D & E and ISO8178-1 for measuring HC, CO, PM, NOx. Data shown is based on steady state operating conditions of 77ºF, 28.42 in HG and number 2 diesel fuel with 35º API and LHV of 18,390 btu/lb. The nominal emissions data shown is subject to instrumentation, measurement, facility and engine to engine variations. Emissions data is based on 100% load and thus cannot be used to compare to EPA regulations which use values based on a weighted cycle.

RATING DEFINITIONS AND CONDITIONS

Meets or Exceeds International Specifications: AS1359, CSA, IEC60034-1, ISO3046, ISO8528, NEMA MG 1-22, NEMA MG 1-33, UL508A, 72/23/EEC, 98/37/EC, 2004/108/EC

Standby - Output available with varying load for the duration of the interruption of the normal source power. Average power output is 70% of the standby power rating. Typical operation is 200 hours per year, with maximum expected usage of 500 hours per year. Standby power in accordance with ISO8528. Fuel stop power in accordance with ISO3046. Standby ambients shown indicate ambient temperature at 100% load which results in a coolant top tank temperature just below the shutdown temperature.

Ratings are based on SAE J1349 standard conditions. These ratings also apply at ISO3046 standard conditions.

Fuel rates are based on fuel oil of 35° API [16° C (60° F)] gravity having an LHV of 42 780 kJ/kg (18,390 Btu/lb) when used at 29° C (85° F) and weighing 838.9 g/liter (7.001 lbs/U.S. gal.). Additional ratings may be available for specific customer requirements, contact your Cat representative for details. For information regarding Low Sulfur fuel and Biodiesel capability, please consult your Cat dealer.

DIMENSIONS

Package Dimensions		
Length	6631.6 mm	261.09 in
Width	2089.4 mm	82.26 in
Height	2207.9 mm	86.93 in

NOTE: For reference only - do not use for installation design. Please contact your local dealer for exact weight and dimensions. (General Dimension Drawing #3269431).

Performance No.: DM8448

Feature Code: 175DE13

Gen. Arr. Number: 2628258

Source: U.S. Sourced

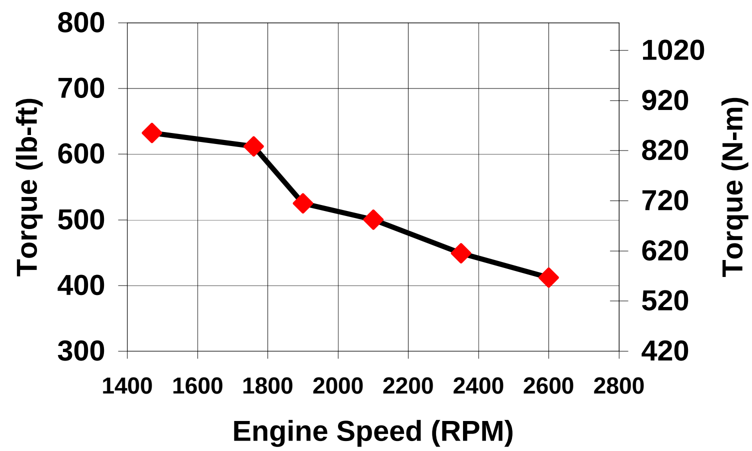
www.Cat-ElectricPower.com

Fire Power	**Engine Performance Curve** **Cummins Fire Power** De Pere, WI 54115 http://www.cumminsfirepower.com	**Basic Engine Model** **CFP7E-F30**
		Curve Number: **FR - 91422**
		Revision Date: **March 2010**

Engine Family:	**Industrial**	CPL Code:	**8611**
Displacement - in.3 (liter):	**409 (6.7)**	Emission Certification:	**EPA/CARB Tier 3**
Compression Ratio:	**17.2:1**	Aspiration:	**Turbocharged, Chrg Air Cooled**
No. of Cylinders:	**6**	Engine Configuration:	**D313013CX03**
Fuel System:	**Bosch Electronic CR**	Minimum speed:	**1470 RPM**
		Maximum speed:	**2700 RPM**

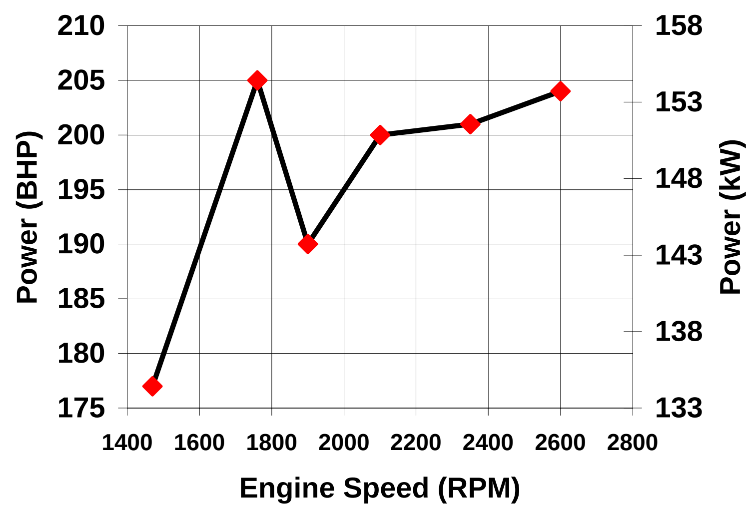
Torque Output

RPM	lb-ft	N-m
1470	632	857
1760	612	829
1900	525	712
2100	500	678
2350	449	609
2600	412	559
2700	290	393



Horsepower Output

RPM	BHP	kW
1470	177	132
1760	205	153
1900	190	142
2100	200	149
2350	201	150
2600	204	152
2700	149	111



1. Curves shown above represent mature gross engine performance capabilities obtained and corrected in accordance with SAE J1349 conditions of 29.61 in Hg (100 kPa) barometric pressure [300 ft. (91.4 m) altitude], 77 ^{o}F (25 ^{o}C) inlet air temperature, and 0.30 in. Hg (1 kPa) water vapor pressure with No. 2 diesel fuel.

2. The engine may be operated without changing the fuel setting up to 300 ft. (91.4 m) altitude and up to 77 ^{o}F (25 ^{o}C) ambient temperature. For sustained operation at high altitudes, the fuel rate of the engine should be adjusted to limit performance by 3% per 1,000 ft. (305 m) above 300 ft. (91.4 m) altitude. For sustained operation at high ambient temperatures, the fuel rate of the engine should be adjusted to limit performance by 1% per 10 ^{o}F above 77 ^{o}F (2% per 11 ^{o}C above 25 ^{o}C).

3. Engine is certified at speeds between 1470 and 2700 RPM.

Jim Vanden Boogard
Director of Engineering

Certified Within 5%

Cummins Fire Power	**Engine Datasheet** **Cummins Fire Power** De Pere, WI 54115 http://www.cumminsfirepower.com	Basic Engine Model **CFP7E-F10,F20,F30,F40, F50, F60**
		Curve Number: **FR - 91422**
		CPL Code: **8611**
Configuration Number: **D313013CX03**		Engine Family: **Industrial**
Installation Drawing: **15547**		Revision Date: **March 2010**

General Engine Data

Type	4 Cycle; In-Line; 6 Cylinder	
Aspiration	Turbocharged, Chrg Air Cooled	
Bore & Stroke - in. (mm)	4.21 x 4.88	(107 x 124)
Displacement - in.^{3} (litre)	409	(6.7)
Compression Ratio	17.2:1	
Valves per Cylinder - Intake	4	
- Exhaust	4	
Maximum Allowable Bending Moment @ Rear Face of Block - lb.-ft. (N-m)	1000	(1356)

Air Induction System

Max. Temperature Rise Between Ambient Air and Engine Air Inlet - ^oF (^oC)	30.6	(17.0)
Maximum Inlet Restriction with Dirty Filter - in. H_2O (mm H_2O)	25	(635)
Recommended Air Cleaner Element - (Standard) FLG Industrial	AH1196	

Lubrication System

Oil Pressure Range at Rated - PSI (kPa)	40-70	(276-414)
Oil Capacity of Pan (High - Low) - U.S. quarts (litre)	15-13	(14-16)
Total System Capacity - U.S. Gal. (litre)	4.0	(15.1)
Recommended Lube Oil Filter Fleetguard (Cummins)	LF3970	(3401544)

Cooling System

Raw Water Working Pressure Range at Heat Exchanger - PSI (kPa)	60	(413) MAX
Recommended Min. Water Supply Pipe Size to Heat Exchanger - in. (mm)	0.75	(19.05)
Recommended Min. Water Disch. Pipe Size From Heat Exchanger - in. (mm)	1.00	(25.40)
Coolant Water Capacity (Engine Side) - U.S. gal. (litre)	3.75	(14.2)
Standard Thermostat - Type	Modulating	
- Range - deg F (deg C)	180-199	(82-93)
Minimum Raw Water Flow		
with Water Temperatures to 50 ^oF (10 ^oC) - U.S. GPM (litre/s)	20	(1.26)
with Water Temperatures to 75 ^oF (24 ^oC) - U.S. GPM (litre/s)	25	(1.58)
with Water Temperatures to 90 ^oF (32 ^oC) - U.S. GPM (litre/s)	30	(1.89)

A jacket water heater is mandatory on this engine. The recommended heater wattage is 1500 down to 40 ^oF (4 ^oC).

Exhaust System

Max. Back Pressure Imposed by Complete Exhaust System in in. H_2O (kPa)	40.8	(10.2)
Exhaust Pipe Size Normally Acceptable - in. (mm)	4.0	(102)

Noise Emissions

Top	92.5 dBa
Right Side	94.3 dBa
Left Side	93.8 dBa
Front	92.1 dBa
Exhaust	114.2 dBa

The noise emission values are estimated sound pressure levels at 3.3 ft. (1 m.).

Fuel Supply / Drain System

Fuel Consumption		1470		1760		1900		2100		2350		2600		2700	
CFP7E-F60	Gal/hr (L/hr) ….	11.3	(42.7)	12.9	(48.9)	12.0	(45.5)	12.8	(48.4)	13.1	(49.6)	14.0	(53.1)	10.3	(38.8)
CFP7E-F50	Gal/hr (L/hr) ….	10.6	(40.1)	12.1	(46.0)	11.3	(42.8)	12.0	(45.4)	12.4	(46.8)	13.2	(49.9)	9.6	(36.5)
CFP7E-F40	Gal/hr (L/hr) ….	9.9	(37.6)	11.4	(43.0)	10.6	(40.0)	11.3	(42.6)	11.6	(43.8)	12.3	(46.7)	9.0	(34.1)
CFP7E-F30	Gal/hr (L/hr) ….	9.1	(34.6)	10.6	(40.1)	9.8	(37.3)	10.5	(40.7)	10.8	(40.7)	11.5	(43.5)	8.4	(31.8)
CFP7E-F20	Gal/hr (L/hr) ….	8.6	(32.5)	9.8	(37.2)	9.1	(34.5)	9.7	(36.7)	10.0	(37.9)	10.6	(40.3)	7.8	(29.4)
CFP7E-F10	Gal/hr (L/hr) ….	7.9	(29.9)	9.0	(34.2)	9.2	(31.8)	9.0	(33.9)	9.2	(34.8)	9.8	(37.1)	7.2	(27.1)

Fuel Type ……………………………………………………………………	Number 2 Diesel Only	
Minimum Supply Line Size - in. (mm) ……………………………………………	0.5	(12.70)
Minimum Drain Line Size - in. (mm) ……………………………………………	0.375	(9.53)
Maximum Fuel Height above C/L Fire Pump ft (m) ………………………………..	30	(9)
Recommended Fuel Filter - Primary ………………………..…… Fleetguard (Cummins)..….	FF5612	(4989106)
- Secondary ……………………………………………………	FS1212	(3308638)
Maximum Restriction @ Lift Pump-Inlet - With Clean Filter - in. Hg (mm Hg) …………………….	5.0	(127)
Maximum Restriction @ Lift Pump-Inlet - With Dirty Filter - in. Hg (mm Hg) ………………………	10.0	(254)
Maximum Return Line Restriction - Without Check Valves - in. Hg (mm Hg) …………………….	5.9	(150)
Minimum Fuel Tank Vent Capability - ft^3/hr (m^3/hr) ………………………………………	7.1	(0.21)
Maximum Fuel Temperature @ Lift Pump Inlet - ^oF (^oC) …………………………………	158	(70)

Starting and Electrical System

	12V	24V
Min. Recommended Batt. Capacity - Cold Soak at 0^oF (-18^oC) or Above		
Engine Only - Cold Cranking Amperes - (CCA) ……………………………………	1500	900
Engine Only - Reserve Capacity - Minutes …………………………………………	430	430
Battery Cable Size (Maximum Cable Length Not to Exceed 5 ft. [1.5 m] AWG) …………………	2/0	2/0
Maximum Resistance of Starting Circuit - Ohms ………………………………………	0.001	0.002
Typical Cranking Speed - RPM ………………………………………………………	120	120
Alternator (Standard), Internally Regulated - Ampere ………………………………	95	70
Wiring for Automatic Starting (Negative Ground) ………………………………………	Standard	
Reference Wiring Diagram ………………………………………………………………	16260	

Performance Data

All data is based on the engine operating with fuel system, water pump, lubricating oil pump, air cleaner, and alternator; not included are compressor, fan, optional equipment, and driven components. Data is based on operation at SAE standard J1394 conditions of 300 ft. (91.4 m) altitude, 29.61 in. (752 mm) Hg dry barometer, and 77 ^oF (25 ^oC) intake air temperature, using No.2 diesel or a fuel corresponding to ASTM-D2.

Altitude Above Which Output Should be Limited - ft. (m) ………………………………	300	(91.4)
Correction Factor per 1000 ft. (305 m) above Altitude Limit ……………………………	3%	
Temperature Above Which Output Should be Limited - ^oF (^oC) ………………………	77	(25)
Correction Factor per 10 ^oF (11 ^oC) Above Temperature Limit ………………………	1%	(2%)

Exhaust Emissions (EPA Tier T3) [Reference Emissions Data Doc. 9814]

	g/kW-hr	g/BHP-hr
Hydrocarbons (HC/OMHCE)………………………………………………	0.120	0.09
Oxides of Nitrogen (NOx)………………………………………………	0.335	0.25
Non-Methane Hydrocarbons + NOx (NMHC+NOx)………………………………	0.370	0.28
Carbon Monoxide (CO)…………………………………………………	1.60	1.19
Particulate……………………………………………………………	0.17	0.13

FM Approved and UL Listed Ratings for CFP7E-F10, F20, F30, F40, F50, F60

Engine Speed - RPM	1470	1760	1900	2100	2350	2600	2700
CFP7E-F60 Output - BHP (kW)	**218 (163)**	**250 (186)**	**232 (173)**	**244 (182)**	**245 (183)**	**249 (186)**	**182 (136)**
Ventilation Air CFM (litre/sec)	479.6 (226)	536.9 (253)	524 (247)	580 (274)	636 (300)	699.6 (330)	643.6 (304)
Exhaust Flow - CFM (litre/sec)	1194 (564)	1344 (634)	1297 (612)	1439 (679)	1557 (735)	1713 (808)	1576 (744)
Exhaust Temp.- °F (°C) . #	1012 (544)	1004 (540)	913 (489)	934 (501)	939 (504)	1033 (556)	1023 (550)
Heat Rejection							
To Coolant BTU/min. (kW)	4291 (75)	4615 (81)	4367 (77)	4672 (82)	4997 (88)	5497 (97)	5222 (92)
To Ambient BTU/min (kW)	1090 (19)	1160 (20)	1261 (22)	1362 (24)	1488 (26)	1564 (27)	1533 (27)
CFP7E-F50 Output - BHP (kW)	**205 (153)**	**235 (175)**	**218 (163)**	**229 (171)**	**231 (172)**	**234 (174)**	**171 (128)**
Ventilation Air CFM (litre/sec)	456.8 (216)	511.4 (241)	519 (245)	576 (272)	634 (299)	697.4 (329)	641.6 (303)
Exhaust Flow - CFM (litre/sec)	1117 (527)	1280 (604)	1263 (596)	1390 (656)	1538 (726)	1692 (799)	1556 (735)
Exhaust Temp.- °F (°C)	978 (526)	956.6 (514)	887 (475)	902 (483)	925 (496)	1018 (548)	1007 (542)
Heat Rejection							
To Coolant BTU/min. (kW)	4031 (71)	4395 (77)	4165 (73)	4447 (78)	4895 (86)	5385 (95)	5115 (90)
To Ambient BTU/min (kW)	1057 (19)	1125 (20)	1223 (21)	1321 (23)	1444 (25)	1517 (27)	1487 (26)
CFP7E-F40 Output - BHP (kW)	**192 (143)**	**220 (164)**	**204 (152)**	**215 (160)**	**216 (161)**	**219 (163)**	**160 (119)**
Ventilation Air CFM (litre/sec)	435 (205)	487 (230)	511 (241)	571 (270)	629 (297)	691.9 (327)	636.5 (300)
Exhaust Flow - CFM (litre/sec)	1055 (498)	1219 (575)	1218 (575)	1363 (643)	1500 (708)	1650 (779)	1518 (716)
Exhaust Temp.- °F (°C)	954 (512)	911 (488)	853 (456)	874 (468)	897 (481)	986.7 (530)	976.8 (525)
Heat Rejection							
To Coolant BTU/min. (kW)	3803 (67)	4186 (74)	3926 (69)	4263 (75)	4707 (83)	5178 (91)	4919 (86)
To Ambient BTU/min (kW)	1026 (18)	1091 (19)	1186 (21)	1282 (23)	1256 (22)	1231 (22)	1206 (21)
CFP7E-F30 Output - BHP (kW)	**177 (132)**	**205 (153)**	**190 (142)**	**200 (149)**	**201 (150)**	**204 (152)**	**149 (111)**
Ventilation Air CFM (litre/sec)	403 (190)	480 (227)	502 (237)	567 (268)	627 (296)	689.7 (326)	634.5 (299)
Exhaust Flow - CFM (litre/sec)	1026 (484)	1174 (554)	1180 (557)	1305 (616)	1468 (693)	1615 (762)	1486 (701)
Exhaust Temp.- °F (°C)	939 (504)	879 (471)	828 (442)	836 (447)	872 (467)	959.2 (515)	949.6 (510)
Heat Rejection							
To Coolant BTU/min. (kW)	3622 (64)	3978 (70)	3757 (66)	4043 (71)	4533 (80)	4986 (88)	4737 (83)
To Ambient BTU/min (kW)	994.8 (17)	1059 (19)	1151 (20)	1243 (22)	1218 (21)	1194 (21)	1170 (21)
CFP7E-F20 Output - BHP (kW)	**166 (124)**	**190 (142)**	**176 (131)**	**185 (138)**	**187 (139)**	**189 (141)**	**138 (103)**
Ventilation Air CFM (litre/sec)	396 (187)	467 (220)	486 (229)	562 (265)	621 (293)	683.1 (322)	628.5 (297)
Exhaust Flow - CFM (litre/sec)	994 (469)	1121 (529)	1134 (535)	1286 (607)	1422 (671)	1564 (738)	1439 (679)
Exhaust Temp.- °F (°C)	922 (494)	848 (453)	801 (427)	821 (438)	840 (449)	924 (496)	914.8 (490)
Heat Rejection							
To Coolant BTU/min. (kW)	3486 (61)	3745 (66)	3523 (62)	3877 (68)	4343 (76)	4777 (84)	4538 (80)
To Ambient BTU/min (kW)	965 (17)	1027 (18)	1116 (20)	1206 (21)	1182 (21)	1158 (20)	1135 (20)
CFP7E-F10 Output - BHP (kW)	**153 (114)**	**175 (130)**	**162 (121)**	**171 (128)**	**172 (128)**	**174 (130)**	**127 (95)**
Ventilation Air CFM (litre/sec)	386 (182)	450 (212)	472 (223)	558 (263)	616 (291)	677.6 (320)	623.4 (294)
Exhaust Flow - CFM (litre/sec)	937 (442)	1061 (501)	1079 (509)	1255 (592)	1375 (649)	1513 (714)	1392 (657)
Exhaust Temp.- °F (°C)	906 (486)	821 (438)	781 (416)	795 (424)	805 (429)	885.5 (474)	876.6 (469)
Heat Rejection							
To Coolant BTU/min. (kW)	3259 (57)	3521 (62)	3232 (57)	3698 (65)	4126 (73)	4539 (80)	4312 (76)
To Ambient BTU/min (kW)	936 (16)	996.1 (18)	1083 (19)	1170 (21)	1146 (20)	1123 (20)	1101 (19)

All Data is Subject to Change Without Notice.

Director of Engineering: ***Jim Vanden Boogard***

Cummins Fire Power, De Pere, WI 54115 U.S.A.

EPA Tier 3 Emission Data
Fire Pump NSPS Compliant

CFP7E-F30 Fire Pump Driver

Type: 4 Cycle; In-Line; 6 Cylinder
Aspiration: Turbocharged, Charge Air Cooled

15 PPM Diesel Fuel																	
		Fuel Consumption		**D2 Cycle Exhaust Emissions**										**Exhaust**			
				Grams per BHP - HR					**Grams per kW - HR**					Temperature		Gas Flow	
RPM	BHP	Gal/Hr	L/hr	NMHC	NOx	NMHC+NOx	CO	PM	NMHC	NOx	NMHC+NOx	CO	PM	°F	°C	CFM	L/sec
1470	179	9.3	35.2											939	504	1026	484
1760	205	10.6	40.1											879	471	1174	554
1900	190	9.8	37.1											828	442	1180	557
2100	200	10.5	39.7	0.062	2.475	2.537	1.193	0.111	0.083	3.319	3.402	1.600	0.149	836	447	1305	616
2350	201	10.8	40.9											872	467	1468	693
2600	204	11.5	43.5											959	515	1615	762
2700	149	8.4	31.8											950	510	1489	703

The emissions values above are based on CARB approved calculations for converting EPA (500 ppm) fuel to CARB (15 ppm) fuel.

300-4000 PPM Diesel Fuel																	
		Fuel Consumption		**D2 Cycle Exhaust Emissions**										**Exhaust**			
				Grams per BHP - HR					**Grams per kW - HR**					Temperature		Gas Flow	
RPM	BHP	Gal/Hr	L/hr	NMHC	NOx	NMHC+NOx	CO	PM	NMHC	NOx	NMHC+NOx	CO	PM	°F	°C	CFM	L/sec
1470	179	9.3	35.2											939	504	1026	484
1760	205	10.6	40.1											879	471	1174	554
1900	190	9.8	37.1											828	442	1180	557
2100	200	10.5	39.7	0.075	2.685	2.759	1.193	0.127	0.1	3.600	3.700	1.600	0.170	836	447	1305	616
2350	201	10.8	40.9											872	467	1468	693
2600	204	11.5	43.5											959	515	1615	762
2700	149	8.4	31.8											950	510	1489	703

QSB6.7 Base Model Manufactured by Cummins Inc.
- Using fuel rating 91422

Reference EPA Standard Engine Family: **ACEXL0409AAB**
Reference CARB Executive Order:**U-R-002-0516**

No special options needed to meet current regulation emissions for all 50 states

Test Methods:

EPA/CARB Nonroad emissions recorded per 40CFR89 (ref. ISO8178-1) and weighted at load points prescribed in Subpart E, Appendix A, for Constant Spee Engines (ref. ISO8178-4, D2).

Diesel Fuel Specifications:

Cetane Number: 40-48
Reference: ASTM D975 No. 2-D

Reference Conditions:

Air Inlet Temperature: 25°C (77°F)
Fuel Inlet Temperature: 40°C (104°F)
Barometric Pressure: 100 kPa (29.53 in Hg)
Humidity: 10.7 g/kg (75 grains H_2O/lb) of dry air; required for NOx correction

Restrictions: Intake Restriction set to a maximum allowable limit for clean filter; Exhaust Back Pressure set to maximum allowable limit.

Tests conducted using alternate test methods, instrumentation, fuel or reference conditions can yield different results.

Revision Date: 24MAR2010