CHENIERE

Cheniere Energy, Inc.
700 Milam Street, Suite 800
Houston, Texas 77002
phone: 713.375.5000
fax: 713.375.6000

August 31, 2012

Mr. Jeff Robinson
Air Permits Section Chief
U.S. Environmental Protection Agency, (6PD-R)
1445 Ross Ave
Dallas, TX 75202-2733

RE: Cheniere Corpus Christi Pipeline, L.P.
Sinton Compressor Station
Application for GHG PSD Air Permit

Mr. Robinson:

Cheniere Corpus Christi Pipeline, L.P. (CCPL), a subsidiary of Cheniere Energy, Inc. (Cheniere), is pleased to submit an original of the enclosed application requesting federal Prevention of Significant Deterioration (PSD) authorization for the proposed Sinton Compressor Station Project. The Project consists of a new compressor station to service the Corpus Christi Pipeline, at a site that is approximately 3 miles northeast of Sinton, Texas, in San Patricio County.

Natural gas will be transported to the Sinton Compressor Station via the Corpus Christi Pipeline. Two highly efficient natural gas-fired turbines will be used to compress the natural gas for onward transport through the Corpus Christi Pipeline, and one natural gas-fired standby generator will also be located on-site for backup power supply. The Station will utilize best available control technology (BACT) to reduce air emissions of air pollutants.

An application for state air quality and federal Prevention of Significant Deterioration (PSD) permit to authorize the non-GHG emissions from the Sinton Compressor Station is being concurrently submitted to the Texas Commission on Environmental Quality (TCEQ). CCPL proposes that, in addition to issuing the state air quality permit, the TCEQ perform the PSD review for NO_x, CO, PM, PM_{10} and $PM_{2.5}$. CCPL will work with EPA and TCEQ to ensure that the appropriate preconstruction air quality permits are issued for the project and that the required PSD demonstrations are made for all pollutants subject to PSD review.

Thank you in advance for your consideration of this application. We respectfully request that staff complete its review of the application for this important project in an expeditious manner.

We would be pleased to meet with you or your staff at any time should you have any questions concerning this application. Please contact me at 713.375.5212 with any questions or requests for more information.

Sincerely,

Patricia Outtrim
Vice President, Government & Regulatory Affairs

cc: Mr. Mike Wilson, P.E., Director, Air Permits Division, TCEQ
Ms. Susan Clewis, Regional Director, TCEQ Region 14 - Corpus Christi

AUGUST 2012

CHENIERE CORPUS CHRISTI PIPELINE, L.P.
SINTON COMPRESSOR STATION

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) AND GREENHOUSE GAS PERMIT APPLICATION

Prepared By:

Providence
11767 Katy Freeway
Suite 430
Houston, TX 77079
(281) 497-5656

www.providenceeng.com

Project Number 287-011

PROVIDENCE

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1.0 INTRODUCTION

1.0 INTRODUCTION

1.1 Background

Corpus Christi Pipeline, L.P. (CCPL), a subsidiary of Cheniere Energy, Inc. (Cheniere), proposes to build, own and operate the Corpus Christi Pipeline which will interconnect five existing inter- and intrastate pipelines and Cheniere's proposed Corpus Christi LNG terminal. To provide adequate throughput capacity on the pipeline, CCPL is proposing to construct the Sinton Compressor Station approximately 3 miles northeast of Sinton, Texas, in San Patricio County. **Figure 1** shows the location of the proposed Sinton Compressor Station with respect to the immediate surroundings.

CCPL is submitting this Prevention of Significant Deterioration (PSD) application in accordance with 30 TAC §116.160. PSD is part of the federal New Source Review (NSR) permitting program for criteria pollutants in an attainment area. San Patricio County, which is located in Air Quality Control Region (ACQR) 214, is designated as "unclassifiable" or "in attainment" for all pollutants in regards to the National Ambient Air Quality Standards (NAAQS). As of July 2011, emissions of greenhouse gases (GHG) are regulated under the Clean Air Act and subject to the PSD program. The proposed Sinton Compressor Station has the potential to emit greater than 100,000 tons per year (tpy) CO_2e. As such, a concurrent GHG permit is being submitted to EPA Region 6. As the facility is a new major source for PSD purposes, all proposed criteria pollutants emitted in amounts greater than or equal to the PSD significance emission rate (SER) are subject to PSD review.

Once PSD permitting has been triggered for a single pollutant, the thresholds for the remaining pollutants drop to the significant emission thresholds as shown in 40 CFR 52.21(b)(23). As a result of the required PSD permitting due to the levels of GHG emissions, the following pollutants are also subject to PSD review: NOx, CO, PM, PM_{10}, and $PM_{2.5}$. Concurrent with the filing of this application, CCPL is filing a PSD and state NSR application with the TCEQ, proposing that the TCEQ perform PSD review for NOx, CO, PM, PM_{10}, and $PM_{2.5}$. CCPL will work with EPA and TCEQ to ensure that the appropriate PSD preconstruction air quality permits are issued for the project and that the required PSD demonstrations are made for all pollutants subject to PSD review.

1.2 Process Description

Natural gas will be transported to the Sinton Compressor Station via the Corpus Christi Pipeline. Condensate and produced water will be separated from the natural gas, stored in a 103 barrel storage tank, and periodically loaded into tank trucks and shipped off-site. Two (2) 20,794 horsepower (15.5 MW) Solar Titan 134-20502S natural gas-fired turbines or its equivalent will be used to compress the natural gas for onward transport through the Corpus Christi Pipeline. One (1) 1,328 horsepower (0.99 MW) Waukesha VHP5904LTD natural gas-fired standby generator or its equivalent will also be located on-site for backup power supply.

1.3 Project Description

CCPL proposes to build, own and operate the Sinton Compressor Station to enhance bi-directional flow along the proposed Corpus Christi Pipeline. The Sinton Compressor Station is being designed with an annual average throughput capacity of 2.0 billion cubic feet per day.

1.4 Emission Sources and Controls

Criteria pollutants from this facility will include nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOCs), sulfur dioxide (SO_2), particulate matter with an aerodynamic particle diameter less than or equal to 10 microns (PM_{10}) and particulate matter with an aerodynamic particle diameter less than or equal to 2.5 microns ($PM_{2.5}$). Manufacturer data indicates that all total suspended particulates (TSP) are less than 1 micron in diameter; therefore, it is assumed that PM_{10} and $PM_{2.5}$ are equivalent. Based on the natural gas composition, hazardous air pollutants (HAPs) are also emitted in small quantities. The proposed Sinton Compressor Station's potential to emit for HAPs is less than 10 tpy for any single HAP and less than 25 tpy for combined HAPs; therefore, this facility is not a major source for HAPs.

Generally, emission factors from EPA's Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume I: *Stationary Point and Area Sources*, vendor emission data, material balances, and other emission factors were used to estimate emissions. Emission calculations are presented in Section 4.

Air emissions will be primarily combustion products generated from firing natural gas in the turbines and standby generator. VOCs will be generated during flashing at the condensate tank, the loading operations, and fugitive emissions from piping and equipment leaks.

Because the facility has the potential to emit greater than 100 tpy of several criteria pollutants and over 100,000 tpy CO_2e, the facility will be a major source with regards to the federal operating permits program outlined in 40 CFR Part 70.

2.0 REGULATORY APPLICABILITY

2.0 REGULATORY APPLICABILITY

The Sinton Compressor Station will be subject to federal air quality regulations. A regulatory review that describes and cites applicable federal air quality requirements and standards for the affected sources at the facility is provided below.

2.1 New Source Review (PSD and NNSR)

The Sinton Compressor Station will be located in San Patricio County, which is in attainment for all criteria pollutants; therefore, Nonattainment New Source Review (NNSR) does not apply.

As of July of 2011, emissions of GHG are regulated under the Clean Air Act and subject to the PSD program. The Sinton Compressor Station will be a new major source due to the potential to emit CO_2e at a rate greater than 100,000 tpy. As a major source under PSD, all proposed attainment pollutants emitted in amounts greater than or equal to the PSD significance levels are subject to PSD review. **Table 2-1** shows the proposed allowable emission rates for regulated attainment pollutants compared to the PSD significance level. PSD review is required for CO_2e, CO, NO_X, PM, $PM_{2.5}$, and PM_{10}.

Table 2-1
Proposed Emissions Compared to PSD Significance Thresholds

Pollutant	Project Emissions (TPY)	Significant Emission Rate (TPY)	PSD Review Required
NO_X	130.10	40	Yes
PM	26.92	25	Yes
PM_{10}	26.92	15	Yes
$PM_{2.5}$	26.92	10	Yes
CO	196.18	100	Yes
SO_2	17.53	40	
CO_2e	155,356	100,000	Yes

Major stationary sources subject to PSD review are required to conduct the following analyses:

1. *Best Available Control Technology (BACT)* – The purpose of the BACT analysis is to ensure the application of BACT. BACT analysis is included as **Appendix B.**

2. *Air Quality Analysis* – The intent of the Air Quality Analysis is to show that proposed emissions will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD

increment. However, due to the nature of GHG emissions as a "global pollutant", NAAQS have not been established for GHGs and air dispersion modeling for GHGs is not required. The air quality analyses for the remaining pollutants that will be evaluated for PSD permitting under this project will be submitted at a later date if requested by EPA.

3. *Endangered Species Act and National Historic Preservation Act Analysis* – Any potential impacts of the proposed project with respect to the Endangered Species Act and National Historic Preservation Act will be addressed in a separate submittal to EPA**.**

4. *Additional Impacts Analysis* – As part of PSD review, a facility must demonstrate that the proposed project will not have a significant impact on ambient air quality, soils and vegetation, visibility (particularly in designated "Class I" areas), or the potential for future commercial growth. EPA's GHG permitting guidance states that, for PSD GHG applications, "the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent."[1] At the same time, incorporation of GHGs into the PSD permitting program did not affect the need for permitting authorities to address these requirements for other regulated NSR pollutants.

2.2 New Source Performance Standards (NSPS)

<u>40 CFR 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels</u>

This subpart applies to each storage vessel with a capacity greater than or equal to 75 cubic meters that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984. The condensate tank (TK0001) is exempt from NSPS Subpart Kb (Storage Vessels) because the storage capacity is less than 75 cubic meters.

<u>40 CFR 60 Subpart JJJJ – Stationary Spark Ignition Combustion Engines</u>

Owners and operators of emergency engines with a maximum engine power greater than 25 HP that commence construction after July 12, 2006 and are manufactured after January 1, 2009 are subject to this regulation. EPN EQT005 will be subject to the requirements of 40 CFR 60 Subpart JJJJ for emergency engines.

[1] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* at p.17 (March 2011) ("GHG Permitting Guidance").

40 CFR 60 Subpart KKKK – Stationary Combustion Turbines

The turbines are subject to NSPS Subpart KKKK (Stationary Combustion Turbines) because the heat input rates at peak loads, for each turbine, exceed 10 MMBtu per hour. Therefore, the turbines must meet the NO_X emission limitations in Table 1 of this subpart.

For turbines which do not employ water or steam injection to control NO_X emissions, annual performance tests must be conducted to demonstrate continuous compliance in accordance with §60.4400. If the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine, the frequency of subsequent performance tests may be reduced to once every 2 years. For each turbine that performs annual performance tests in accordance with §60.4340(a), a written report of the results of each performance test must be submitted by the 60th day following the completion of the performance test.

As an alternative to performance testing, continuous parameter monitoring for each turbine may be conducted to demonstrate that the units are operating in low-NO_X mode.

40 CFR 60 Subpart GG Standards of Performance for Stationary Gas Turbines

As the facility is subject to Subpart KKKK, the facility is exempt from this subpart as indicated in §60.4305(b).

40 CFR 60 Subpart OOOO Standards of Performance for Crude Oil and Natural Gas Production, Transmissions and Distribution

The compressors are exempt from this subpart as they are not located between the wellhead and the point of custody transfer as described in §60.5365(b). The condensate storage tank is not subject to emission limitations in this subpart as the VOC emissions are less than 6 tons per year.

2.3 National Emission Standards for Hazardous Air Pollutants (40 CFR Part 63)

40 CFR Part 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

The Sinton Compressor Station is not a major source of HAPs and therefore is considered an area source of HAPs. The standby generator (EPN EQT005) is considered a New Emergency RICE at an Area Source and is required to comply with the requirements of 40 CFR 60 Subpart JJJJ, per 40 CFR 63.6590(c)(1). No other requirements of Subpart ZZZZ apply to this engine.

3.0 TCEQ APPLICATION FORMS

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: **Cheniere Corpus Christi Pipeline, L.P.**		
Texas Secretary of State Charter/Registration Number (*if applicable*):		
B. Company Official Contact Name: **Patricia Outtrim**		
Title: **Vice President Government and Regulatory Affairs**		
Mailing Address: **700 Milam Street, Suite 800**		
City: **Houston**	State: **TX**	ZIP Code: **77002**
Telephone No.: **(713) 375-5212**	Fax No.: **(713) 375-6212**	E-mail Address: **Pat.outtrim@cheniere.com**
C. Technical Contact Name: **Andrew Chartrand**		
Title: **Director, Environmental and Regulatory Projects**		
Company Name: **Cheniere Energy, Inc.**		
Mailing Address: **700 Milam Street, Suite 800**		
City: **Houston**	State: **TX**	ZIP Code: **77002**
Telephone No.: **(713) 375-5429**	Fax No.: **(713) 375-6429**	E-mail Address: **Andrew.Chartrand@cheniere.com**
D. Site Name: **Sinton Compressor Station**		
E. Area Name/Type of Facility: **Sinton Compressor Station**		☒ **Permanent** ☐ Portable
F. Principal Company Product or Business: **Pipeline natural gas compression station.**		
Principal Standard Industrial Classification Code (SIC): **4922**		
Principal North American Industry Classification System (NAICS): **486210**		
G. Projected Start of Construction Date: **06/2016**		
Projected Start of Operation Date: **01/2017**		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: **Proceed northeast on highway 77 from Sinton and turn left onto a paved road in approximately 3.6 miles. Proceed northwest for approximately 1.2 miles. Compressor station will be on the right.**		
City/Town: **Sinton**	County: **San Patricio**	ZIP Code: **78387**
Latitude (nearest second): **28°5'32"**	Longitude (nearest second): **97°29'32'**	

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

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): **TBD**	
L. Regulated Entity Number (RN): **TBD**	
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 or enforcement action? If *Yes*, attach a copy of any correspondence from the agency.	☐ YES ☒ **NO**
C. Number of New Jobs: 2	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
Senator: **Senator Judith Zaffirini**	District No.: **21**
Representative: **Representative Todd A. Hunter**	District No.: **32**
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 ☐ Prevention of Significant Deterioration ☒ Hazardous Air Pollutant Major Source ☐ Plant-Wide Applicability Limit ☐ 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.		☐ 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: **N/A**		
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
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 ☐ **To Be Determined** ☒		
Operational Flexibility/Off-Permit Notification ☐ Streamlined Revision for GOP ☐ 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).		
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*):		
Volatile Organic Compounds (VOC):		
Sulfur Dioxide (SO_2):		
Carbon Monoxide (CO): **196.18 tpy**		
Nitrogen Oxides (NO_x): **130.10 tpy**		
Particulate Matter (PM): **26.92 tpy**		
PM $_{10}$ microns or less (PM_{10}): **26.92 tpy**		
PM $_{2.5}$ microns or less ($PM_{2.5}$): **26.92 tpy**		
Lead (Pb):		
Hazardous Air Pollutants (HAPs):		
Other speciated air contaminants **not** listed above: **CO_2e: 155,356 tpy**		

V. Public Notice Information (complete if applicable)		
A. Public Notice Contact Name: **Andrew Chartrand**		
Title: **Director, Environmental and Regulatory Projects**		
Mailing Address: **700 Milam Street, Suite 800**		
City: **Houston**	State: **TX**	ZIP Code: **77002**
Telephone No.: **(713) 375-5429**		
B. Name of the Public Place: **Sinton Public Library**		
Physical Address (No P.O. Boxes): **100 North Pirate Boulevard**		
City: **Sinton**	County: **San Patricio**	ZIP Code: **78387**
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: **Judge Terry A. Simpson**		
Mailing Address: **400 West Sinton Street, #109**		
City: **Sinton**	State: **TX**	ZIP Code: **78387**
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 of the city for the location where the facility is or will be located.		
Chief Executive: **Pete Gonzales**		
Mailing Address: **P.O. Box 1395**		
City: **Sinton**	State: **TX**	ZIP Code: **78387**

V. Public Notice Information (complete if applicable) (continued)		
3. Provide the name, mailing address of the Indian Governing Body for the location where the facility is or will be located. *(continued)*		
Name of the Indian Governing Body:		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
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?		
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 ☒		
2. Plot Plan ☒		
3. Existing Authorizations ☒		
4. Process Flow Diagram ☒		
5. Process Description ☒		
6. Maximum Emissions Data and Calculations ☒		
7. Air Permit Application Tables ☒		
a. Table 1(a) (Form 10153) entitled, Emission Point Summary ☒		
b. Table 2 (Form 10155) entitled, Material Balance ☒		
c. Other equipment, process or control device tables ☒		

VII. Technical Information				
B. Are any schools located within 3,000 feet of this facility?				☐ YES ☒ **NO**
C. Maximum Operating Schedule:				
Hours:**24**	Day(s):**365**	Week(s):**52**	Year(s):**8760**	
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**
C. Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard 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.***	
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:		Fee Amount: **$75,000**
Company name on check: Cheniere Shared Energy Services, Inc.		Paid online?: ☐ YES ☒ **NO**
Is a copy of the check or money order attached to the original submittal of this application?		☐ **YES** ☒ NO ☐ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?		☒ **YES** ☐ NO ☐ N/A

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: Patricia Outtrim
Signature: Pat Outt *Original Signature Required*
Date: 8/31/12

PROFESSIONAL ENGINEER SEAL

The estimated capital cost of the Sinton Compressor Station PSD Application exceeds $2 million. Therefore, this application is submitted under the seal of a Texas licensed Professional Engineer (P.E.).

Lisa M. Swanson, P.E.
Name

105184
Registration No.

TX
State

STATE OF TEXAS
LISA M. SWANSON
105184
LICENSED
PROFESSIONAL ENGINEER

Signature

8/29/12
Date

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: 8/31/2012	Permit No.: TBD	Regulated Entity No.: TBD
Area Name: Sinton Compressor Station		Customer Reference No.: TBD

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY
EQT001	SCBDS1	Titan 130 Unit A Blowdown Stack	CH_4 CO_2	838.28 30,509.64	1.26 45.76
EQT002	SCBDS2	Titan 130 Unit B Blowdown Stack	CH_4 CO_2	838.28 30,509.64	1.26 45.76
EQT003	SSBDS	Station Suction Blowdown Stack	CH_4 CO_2	109,872.24 3,018.88	54.94 1.51
EQT004	SDBDS	Station Discharge Blowdown Stack	CH_4 CO_2	165,213.04 4,539.40	82.61 2.27
EQT005	SCGEN1	Emergency Generator	NO_X $PM/PM_{10}/PM_{2.5}$ CO CH_4 CO_2	5.85 0.00 5.27 0.02 1,139.97	1.46 0.00 1.32 0.01 284.99

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: 8/31/2012	**Permit No.: TBD**	**Regulated Entity No.: TBD**
Area Name: Sinton Compressor Station		**Customer Reference No.:TBD**

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

AIR CONTAMINANT DATA						**EMISSION POINT DISCHARGE PARAMETERS**							
1. Emission Point			**4. UTM Coordinates of Emission Point**			**Source**							
						5. Building Height (Ft.)	**6. Height Above Ground (Ft.)**	**7. Stack Exit Data**			**8. Fugitives**		
(A) EPN	**(B) FIN**	**(C) NAME**	**Zone**	**East (Meters)**	**North (Meters)**			**(A) Diameter (Ft.)**	**(B) Velocity (FPS)**	**(C) Temperature (°F)**	**(A) Length (Ft.)**	**(B) Width (Ft.)**	**(C) Axis Degrees**
EQT001	SCBDS1	Titan 130 Unit A Blowdown Stack	14	648,123	3,108,275		15	7	109	80			
EQT002	SCBDS1	Titan 130 Unit B Blowdown Stack	14	648,123	3,108,280		15	7	109	80			
EQT003	SSBDS	Station Suction Blowdown	14	648,123	3,108,286		20	8	105	80			
EQT004	SDBDS	Station Discharge Blowdown Stack	14	648,123	3,108,291		20	8	237	80			
EQT005	SCGEN1	Emergency Generator	14	648,201	3,108,380		30	1.333	95	860			

EPN = Emission Point Number
FIN = Facility Identification Number

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: 8/31/2012	**Permit No.: TBD**	**Regulated Entity No.: TBD**
Area Name: Sinton Compressor Station		**Customer Reference No.:TBD**

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

AIR CONTAMINANT DATA					
4. Emission Point			**5. Component or Air Contaminant Name**	**6. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) Name**		**(A) Pound Per Hour**	**(B) TPY**
EQT006	SCPLC1	Gas Compressor A – Titan 130	NO_X CO $PM/PM_{10}/PM_{2.5}$ CH_4 CO_2 N_2O	14.64 1.79 3.07 0.32 17,107.71 0.03	64.11 7.82 13.46 1.41 74,931.78 0.14
EQT007	SCPLC2	Gas Compressor B – Titan 130	NO_X CO $PM/PM_{10}/PM_{2.5}$ CH_4 CO_2 N_2O	14.64 1.79 3.07 0.32 17,107.71 0.03	64.11 7.82 13.46 1.41 74,931.78 0.14
FUG01	SCFUG1	Fugitive Emissions	CH_4	2.25	9.87

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: 8/31/2012	Permit No.: TBD	Regulated Entity No.: TBD
Area Name: Sinton Compressor Station		Customer Reference No.: TBD

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

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS							
2. Emission Point			5. UTM Coordinates of Emission Point			Source							
						9. Building Height (Ft.)	10. Height Above Ground (Ft.)	11. Stack Exit Data			12. Fugitives		
(A) EPN	(B) FIN	(C) NAME	Zone	East (Meters)	North (Meters)			(A) Diameter (Ft.)	(B) Velocity (FPS)	(C) Temperature (°F)	(A) Length (Ft.)	(B) Width (Ft.)	(C) Axis Degrees
EQT006	SCPLC1	Gas Compressor A – Titan 130	14	648,148	3,108,369		39	8.667	68	917			
EQT007	SCPLC2	Gas Compressor B – Titan 130	14	648,168	3,108,369		39	8.667	68	917			
FUG01	SCFUG1	Fugitive Emissions	14	648,127	3,108,263					amb	200	300	0

EPN = Emission Point Number
FIN = Facility Identification Number

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: 8/31/2012	**Permit No.: TBD**	**Regulated Entity No.: TBD**
Area Name: Sinton Compressor Station		**Customer Reference No.: TBD**

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

AIR CONTAMINANT DATA					
7. Emission Point			**8. Component or Air Contaminant Name**	**9. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) Name**		**(A) Pound Per Hour**	**(B) TPY**
EQT006	Startup	Turbine A startup emissions	NO_X CO CO_2	11.40 1,061.40 6,966.00	0.10 8.85 58.05
EQT007	Startup	Turbine B startup emissions	NO_X CO CO_2	11.40 1,061.40 6,966.00	0.10 8.85 58.05
EQT006	Shutdown	Turbine A shutdown emissions	NO_X CO CO_2	14.40 1245.60 7,632.00	0.12 10.38 63.60
EQT007	Shutdown	Turbine B shutdown emissions	NO_X CO CO_2	14.40 1245.60 7,632.00	0.12 10.38 63.60

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: 8/31/2012	Permit No.: TBD	Regulated Entity No.: TBD
Area Name: Sinton Compressor Station		Customer Reference No.: TBD

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

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS							
3. Emission Point			6. UTM Coordinates of Emission Point			Source							
						13. Building Height (Ft.)	14. Height Above Ground (Ft.)	15. Stack Exit Data			16. Fugitives		
(A) EPN	(B) FIN	(C) NAME	Zone	East (Meters)	North (Meters)			(A) Diameter (Ft.)	(B) Velocity (FPS)	(C) Temperature (°F)	(A) Length (Ft.)	(B) Width (Ft.)	(C) Axis Degrees
EQT006	Startup	Turbine A startup emissions	14	648,148	3,108,369		39	8.667	68	917			
EQT007	Startup	Turbine B startup emissions	14	648,168	3,108,369		39	8.667	68	917			
EQT006	Shutdown	Turbine A shutdown emissions	14	648,148	3,108,369		39	8.667	68	917			
EQT007	Shutdown	Turbine B shutdown emissions	14	648,168	3,108,369		39	8.667	68	917			

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		2.0 bscf/day		x	
2. Fuels - Input		7.72 MMscf/day			x
3. Products & By-Products - Output					
4. Solid Wastes - Output					
5. Liquid Wastes - Output		Condensate: 51,889 gal/yr			x
6. Airborne Waste (Solid) - Output					
7. Airborne Wastes (Gaseous) - Output		NOx: 130.10 tpy CO: 196.18 tpy PM/PM10/PM2.5: 26.92 tpy CO2e: 155,356 tpy			x

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data			
Manufacturer: Waukesha, equivalent	Model No. VHP5904LTD	Serial No.	Manufacture Date:
Rebuilds Date:	No. of Cylinders: 12	Compression Ratio: 10.2:1	EPN: EQT005

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**:** 1,328 Proposed Horsepower Rating: 1,328

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (^{o}F)	Exit Velocity (FPS)
30	1.333	860	95

II. Fuel Data

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

Fuel Consumption (BTU/bhp-hr): 7,346 Heat Value: 1045.7 (HHV) (LHV)

Sulfur Content (grains/100 scf - weight %): 5

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
2.00		1.80								.0000257	

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

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

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).

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) EQT006

APPLICATION

_____ Electric Generation
___ Base Load ___ Peaking
X Gas Compression
_____ Other (Specify) _____

CYCLE

____ Simple Cycle
____ Regenerative Cycle
____ Cogeneration
X Combined Cycle

Manufacturer Solar Turbines
Model No. Titan 130-20502S, or equivalent
Serial No. __________

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 20048 hp (MW)(hp)
Proposed Site Operating Range 20048 hp (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 26885 (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.

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) EQT007

APPLICATION

______ Electric Generation
___ Base Load ___ Peaking
X Gas Compression
______ Other (Specify) ______

CYCLE

____ Simple Cycle
____ Regenerative Cycle
____ Cogeneration
X Combined Cycle

Manufacturer Solar Turbines
Model No. Titan 130-20502S, or equivalent
Serial No. ______

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 20048 hp (MW)(hp)
Proposed Site Operating Range 20048 hp (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 26885 (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.

4.0 EMISSION CALCULATIONS

4.0 EMISSION CALCULATIONS

The following pages detail the emission calculations for the Sinton Compressor Station for the pollutants to be reviewed in this application: CO_2e, CO, NO_X, PM, $PM_{2.5}$, and PM_{10}. These calculations are based on EPA's Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume I: *Stationary Point and Area Sources*, vendor emission data, material balance, and other specific emission factors, as applicable. Emissions are presented for normal operations and maintenance, startup, and shutdown (MSS) scenarios for the facility.

Cheniere Corpus Christi Pipeline, L.P.

Company	Facility	
Cheniere Corpus Christi Pipeline, L.P.	Sinton Compressor Station	
Descriptive Name of Emission Point	TEMP Subject Item ID	Emission Point ID No.
Titan 130 - Unit A Blowdown Stack	N/A	EQT001

Emissions Per Event[1]			
Pollutant	5 min	10 min	15 min
	(lb/hr)	(lb/hr)	(lb/hr)
CO_2	2,514.84	1,257.42	838.28
CH_4	91,528.92	45,764.46	30,509.64
CO_2-e	-	-	-

Emissions Per Year[1]			
Pollutant	3 Events	6 Events	12 Events
	TPY	TPY	TPY
CO_2	0.31	0.63	1.26
CH_4	11.44	22.88	45.76
CO_2-e	240.58	481.16	962.31

(1) Emission calculation methodology based upon process simulations using worst case scenario.

Cheniere Corpus Christi Pipeline, L.P.

Company	Facility	
Cheniere Corpus Christi Pipeline, L.P.	Sinton Compressor Station	
Descriptive Name of Emission Point	TEMP Subject Item ID	Emission Point ID No.
Titan 130 - Unit B Blowdown Stack	N/A	EQT002

Emissions Per Event[1]			
Pollutant	5 min	10 min	15 min
	(lb/hr)	(lb/hr)	(lb/hr)
CO_2	2,514.84	1,257.42	838.28
CH_4	91,528.92	45,764.46	30,509.64
CO_2-e	-	-	-

Emissions Per Year[1]			
Pollutant	3 Events	6 Events	12 Events
	TPY	TPY	TPY
CO_2	0.31	0.63	1.26
CH_4	11.44	22.88	45.76
CO_2-e	240.58	481.16	962.31

(1) Emission calculation methodology based upon process simulations using worst case scenario.

Company		Facility
Cheniere Corpus Christi Pipeline, L.P.		Sinton Compressor Station
Descriptive Name of Emission Point	TEMP Subject Item ID	Emission Point ID No.
Station Suction Blowdown Stack	N/A	EQT003

Emissions Per Event[1]			
Pollutant	5 min	10 min	15 min
	(lb/hr)	(lb/hr)	(lb/hr)
CO_2	9,056.64	4,528.32	3,018.88
CH_4	329,616.72	164,808.36	109,872.24
CO_2-e	-	-	-

Emissions Per Year[1]			
Pollutant	2 Events	3 Events	4 Events
	TPY	TPY	TPY
CO_2	0.75	1.13	1.51
CH_4	27.47	41.20	54.94
CO_2-e	577.58	866.38	1,155.17

(1) Emission calculation methodology based upon process simulations using worst case scenario.

Company	Facility	
Cheniere Corpus Christi Pipeline, L.P.	Sinton Compressor Station	
Descriptive Name of Emission Point	TEMP Subject Item ID	Emission Point ID No.
Station Discharge Blowdown Stack	N/A	EQT004

Emissions Per Event(1)			
Pollutant	5 min	10 min	15 min
	(lb/hr)	(lb/hr)	(lb/hr)
CO_2	13,618.20	6,809.10	4,539.40
CH_4	495,639.12	247,819.56	165,213.04
CO_2-e	-	-	-

Emissions Per Year(1)			
Pollutant	2 Events	3 Events	4 Events
	TPY	TPY	TPY
CO_2	1.13	1.70	2.27
CH_4	41.30	61.95	82.61
CO_2-e	868.50	1,302.75	1,737.01

(1) Emission calculation methodology based upon process simulations using worst case scenario.

Company	Facility	
Cheniere Corpus Christi Pipeline, L.P.	Sinton Compressor Station	
Descriptive Name of Emission Point	**Project No.**	**Emission Point ID No.**
Emergency Generator - Waukesha VHP5904LTD	287-011	EQT005

Operating Data[1]		
Manufacturer	Waukesha Dresser	
Model	VHP5904LTD Gas Enginator	
Rating	1,328	bhp
	7,346	Btu/bhp-hr
	9.75	MMBtu/hr
Load Capacity	100	%
Fuel Type	Natural Gas	
Higher Heating Value	1045.7	Btu/scf
Hours of Operations	500	hrs/year

Pollutant	Emission Factor		Reference	Emission Rates		
				Avg (lb/hr)	Max (lb/hr)	Annual (tons/yr)
NO_X	2.00	g/bhp-hr	Manufacturer Specification	5.85	5.85	1.46
CO	1.80	g/bhp-hr	Manufacturer Specification	5.27	5.27	1.32
$PM_{10}/PM_{2.5}$	7.710E-05	lb/MMBtu	AP-42 Table 3.2-2	0.00	0.00	0.00
CO_2	116.89	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-1[2]	1,139.97	1,139.97	284.99
N_2O	2.20E-04	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-2[2]	0.00	0.00	0.00
CH_4	2.20E-03	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-2[2]	0.02	0.02	0.01
CO_2e[2]	-	-	40 CFR 60 Part 98 Subpart A, Table A-1	-	-	285.27

(1) Provided by: Cheniere Corpus Christi Pipeline, L.P.

(2) Global Warming Potentials (GWP) taken from 40 CFR 60 Part 98 Subpart A, Table A-1

(3) Emission factors converted from kg/MMBtu to lb/MMBtu

(4) Emission rates calculated as follows:

Example 1: *Emission rate (lb/hr) = Fuel Consumption (MMBtu/hr) * Emission Factor (lb/MMBtu)*

Example 2: *Emission rate (lb/hr) = Operating Rate (bhp) * Emission Factor (g/bhp-hr) / 453.6 (g/lb)*

Example 3: *CO_2e Emission rate (TPY) = CO_2 ER (TPY)*GWP + N_2O ER (TPY)*GWP+ CH_4 ER (TPY)*GWP*

Example 4: *Fuel Flowrate (MMscf/hr) = Fuel Consumption (MMBtu/hr) / Fuel Heating Value (Btu/scf)*Conversion Factor (10^6 Btu/MMBtu)*Conversion Factor (MMscf/10^6 scf)*

Example 5: *Emissions Rate (lb/hr) = Emission Factor (lb/MMscf)*Fuel Flowrate (MMscf/hr)*

Company	**Facility**	
Cheniere Corpus Christi Pipeline, L.P.	Sinton Compressor Station	
Descriptive Name of Emission Point	**Project No.**	**Emission Point ID No.**
Gas Driven Compressor Unit A - Titan 130	287-011	EQT006

Operating Data[1]		
Manufacturer	Solar Turbines	
Model	Titan 130-20502S	
Rating	20,794	hp
	7,039	Btu/hp-hr
	146.36	MMBtu/hr
Load Capacity	100	%
Fuel Type	Natural Gas	
Higher Heating Value	1045.7	Btu/scf
Hours of Operations	8760	hrs/year
Control Device	Oxidation Catalyst	
Control Efficiency	90	%

Pollutant	Emission Factor		Reference	Emission Rates Avg (lb/hr)	Emission Rates Max (lb/hr)	Emission Rates Annual (tons/yr)
NO_X	1.00E-01	lb/MMBtu	Manufacturer Specification	14.64	14.64	64.11
CO	1.22E-01	lb/MMBtu	Manufacturer Specification	17.86	17.86	78.21
$PM_{10}/PM_{2.5}$[2]	2.10E-02	lb/MMBtu	Manufacturer Specification	3.07	3.07	13.46
CO_2	116.89	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-1[5]	17,107.71	17,107.71	74,931.78
N_2O	2.20E-04	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-1[5]	0.03	0.03	0.14
CH_4	2.20E-03	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-1[5]	0.32	0.32	1.41
CO_2e[3]	-	-	40 CFR 60 Part 98 Subpart A, Table A-1	-	-	75,005.27

(1) Provided by: Cheniere Corpus Christi Pipeline, L.P.

(2) All Particulate Matter assumed less than 1 micron in diameter based on Solar Turbine PIL 171 "Particulate Matter Emission Estimates"

(3) Global Warming Potentials (GWP) taken from 40 CFR 60 Part 98 Subpart A, Table A-1

(4) Emission factors converted from kg/MMBtu to lb/MMBtu

(5) Emission rates calculated as follows:

Example 1: *Emission rate (lb/hr) = Fuel Consumption (MMBtu/hr) * Emission Factor (lb/MMBtu)*

Example 2: *Emission rate (lb/hr) = Operating Rate (bhp) * Emission Factor (g/bhp-hr) / 453.6 (g/lb)*

Example 3: *CO_2e Emission rate (TPY) = CO_2 ER (TPY)*GWP + N_2O ER (TPY)*GWP+ CH_4 ER (TPY)*GWP*

Example 4: *Fuel Flowrate (MMscf/hr) = Fuel Consumption (MMBtu/hr) / Fuel Heating Value (Btu/scf)*Conversion Factor (10^6 Btu/MMBtu)*Conversion Factor (MMscf/10^6 scf)*

Example 5: *Emissions Rate (lb/hr) = Emission Factor (lb/MMscf)*Fuel Flowrate (MMscf/hr)*

Company	**Facility**	
Cheniere Corpus Christi Pipeline, L.P.	Sinton Compressor Station	
Descriptive Name of Emission Point	**Project No.**	**Emission Point ID No.**
Gas Driven Compressor Unit B - Titan 130	287-011	EQT007

Operating Data[1]		
Manufacturer	Solar Turbines	
Model	Titan 130-20502S	
Rating	20,794	hp
	7,039	Btu/hp-hr
	146.36	MMBtu/hr
Load Capacity	100	%
Fuel Type	Natural Gas	
Higher Heating Value	1045.7	Btu/scf
Hours of Operations	8760	hrs/year
Control Device	Oxidation Catalyst	
Control Efficiency	90	%

Pollutant	Emission Factor		Reference	Emission Rates		
				Avg (lb/hr)	Max (lb/hr)	Annual (tons/yr)
NO_X	1.00E-01	lb/MMBtu	Manufacturer Specification	14.64	14.64	64.11
CO	1.22E-01	lb/MMBtu	Manufacturer Specification	17.86	17.86	78.21
$PM_{10}/PM_{2.5}$[3]	2.10E-02	lb/MMBtu	Manufacturer Specification	3.07	3.07	13.46
CO_2	116.89	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-1[5]	17,107.71	17,107.71	74,931.78
N_2O	2.20E-04	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-2[5]	0.03	0.03	0.14
CH_4	2.20E-03	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-2[5]	0.32	0.32	1.41
CO_2e[3]	-	-	40 CFR 60 Part 98 Subpart A, Table A-1	-	-	75,005.27

(1) Provided by: Cheniere Corpus Christi Pipeline, L.P.

(2) All Particulate Matter assumed less than 1 micron in diameter based on Solar Turbine PIL 171 "Particulate Matter Emission Estimates"

(3) Global Warming Potentials (GWP) taken from 40 CFR 60 Part 98 Subpart A, Table A-1

(4) Emission factors converted from kg/MMBtu to lb/MMBtu

(5) Emission rates calculated as follows:

Example 1: *Emission rate (lb/hr) = Fuel Consumption (MMBtu/hr) * Emission Factor (lb/MMBtu)*

Example 2: *Emission rate (lb/hr) = Operating Rate (bhp) * Emission Factor (g/bhp-hr) / 453.6 (g/lb)*

Example 3: *CO_2e Emission rate (TPY) = CO_2 ER (TPY)*GWP + N_2O ER (TPY)*GWP+ CH_4 ER (TPY)*GWP*

Example 4: *Fuel Flowrate (MMscf/hr) = Fuel Consumption (MMBtu/hr) / Fuel Heating Value (Btu/scf)*Conversion Factor (10^6 Btu/MMBtu)*Conversion Factor (MMscf/10^6 scf)*

Example 5: *Emissions Rate (lb/hr) = Emission Factor (lb/MMscf)*Fuel Flowrate (MMscf/hr)*

Company	**Facility**	
Cheniere Corpus Christi Pipeline, L.P.	Sinton Compressor Station	
Descriptive Name of Emission Point	**TEMP Subject Item ID**	**Emission Point ID No.**
Fugitive Emissions	NA	FUG01

Pollutant	Emission Factor	Reference	Emission Rates		
			Avg (lb/hr)	Max (lb/hr)	Annual (tons/yr)
CH_4	NA	Client Provided	-	2.25	9.87
$CO_2e^{(1)}$	NA	40 CFR 60 Part 98 Subpart A, Table A-1	-	-	207.33

(1) Global Warming Potentials (GWP) taken from 40 CFR 60 Part 98 Subpart A, Table A-1

(2) All emission factors taken from Table 4 for Oil and Gas Production Operations in "Emissions for Equipment Leak Fugitive Components" (Jan, 2008) - Addendum to RG-360A

Cheniere Corpus Christi Pipeline, L.P.

Company	**Facility**	
Cheniere Corpus Christi Pipeline, L.P.	Sinton Compressor Station	
Descriptive Name of Emission Point	**TEMP Subject Item**	**Emission Point ID No.**
Maintenance Startup and Shutdown	N/A	EQT006 and EQT007

Start up Emissions - 10 Minute Startup[1]										
Description	Events per Year	NO_X			CO			CO_2		
		Avg (lb/event)	Max (lb/hr)	TPY	Avg (lb/event)	Max (lb/hr)	TPY	Avg (lb/event)	Max (lb/hr)	TPY
Gas Turbine Driven Compressor Unit A - Taurus 130	100	1.90	11.40	0.10	176.90	1,061.40	8.85	1,161.00	6,966.00	58.05
Gas Turbine Driven Compressor Unit B - Taurus 130	100	1.90	11.40	0.10	176.90	1,061.40	8.85	1,161.00	6,966.00	58.05
Total Startup Emissions				**0.19**			**17.69**			**116.10**

Shutdown Emissions - 10 Minute Shutdown[1]										
Description	Events per Year	NO_X			CO			CO_2		
		Avg (lb/event)	Max (lb/hr)	TPY	Avg (lb/event)	Max (lb/hr)	TPY	Avg (lb/event)	Max (lb/hr)	TPY
Gas Turbine Driven Compressor Unit A - Taurus 130	100	2.40	14.40	0.12	207.60	1,245.60	10.38	1,272.00	7,632.00	63.60
Gas Turbine Driven Compressor Unit B - Taurus 130	100	2.40	14.40	0.12	207.60	1,245.60	10.38	1,272.00	7,632.00	63.60
Total Shutdown Emissions				**0.24**			**20.76**			**127.20**
Total MSS Emissions				**0.43**			**38.45**			**243.30**

(1) Emissions data and maintenance scheduling provided by Manufacturing Specifications.

FIGURE 1 – SITE LOCATION MAP

2,000 1,000 0 2,000 Feet

Legend

3,000 Ft. Radius

Reference

Base map comprised of U.S.G.S. 7.5 minute topographic maps, "Sinton East, TX" and "Sinton West, TX".

Area Map

Prevention of Significant Deterioration (PSD) Permit Application

Sinton, San Patricio County, Texas

Cheniere Corpus Christi Pipeline, L.P.

Sinton Compressor Station

PROVIDENCE

Drawn By	JCS	08/27/12
Checked By	LMH	08/27/12
Approved By	NN	08/27/12

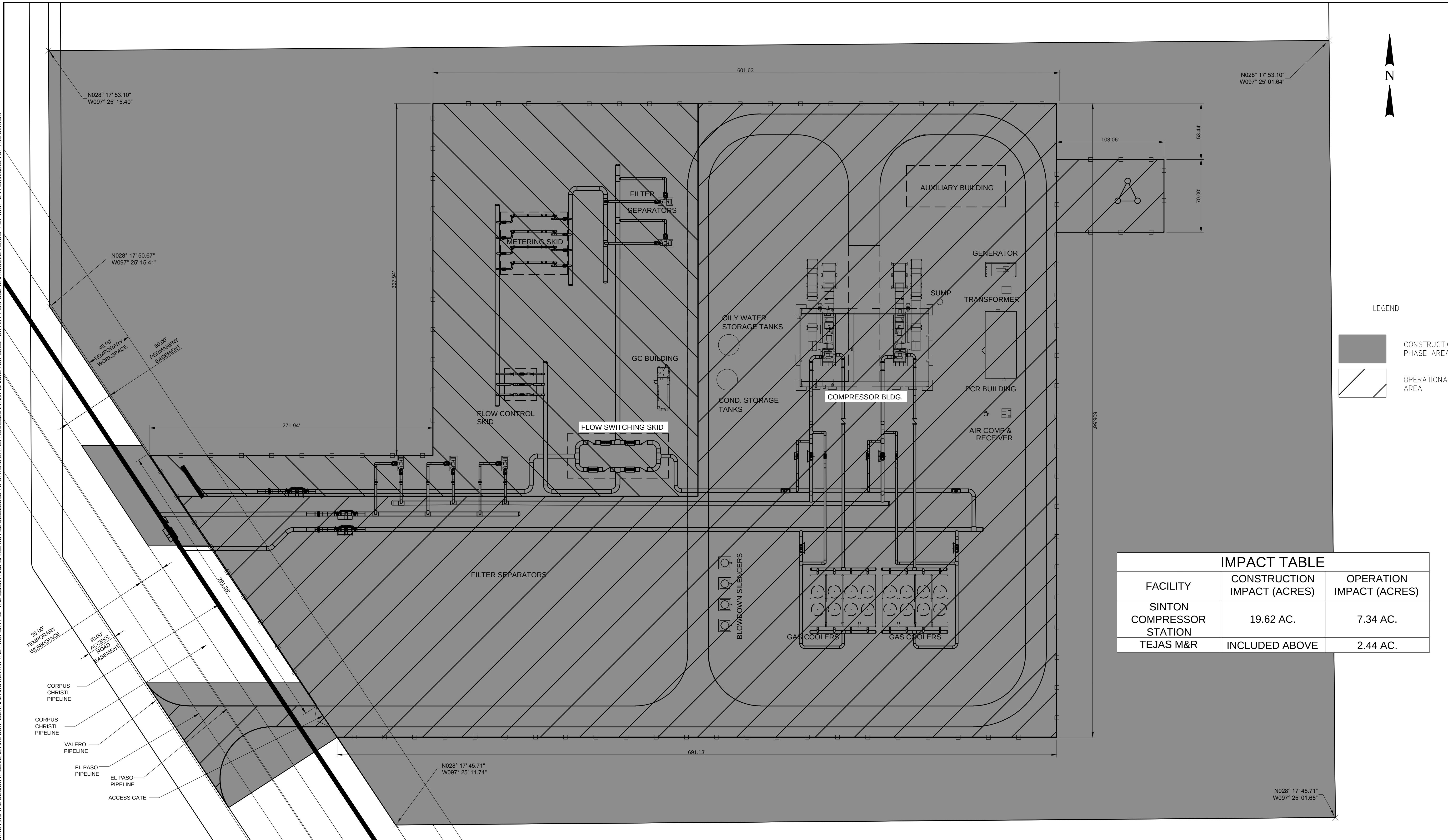
Project Number
287-011

Drawing Number
287-011-A001

1
Figure

Providence Engineering and Environmental Group LLC

FIGURE 2 – FACILITY PLOT PLAN



IMPACT TABLE

FACILITY	CONSTRUCTION IMPACT (ACRES)	OPERATION IMPACT (ACRES)
SINTON COMPRESSOR STATION	19.62 AC.	7.34 AC.
TEJAS M&R	INCLUDED ABOVE	2.44 AC.

NOTES

REFERENCE DRAWINGS

REV.	REVISION	DATE	DRAWN	CHKD.	APPD.
C	ISSUED FOR PERMIT	07/19/12	SMW	MS	RF
B2	ISSUE FOR CLIENT REVIEW	07/13/12	SMW	MS	RF
B1	ISSUED FOR CLIENT REVIEW	07/05/12	SMW	MS	RF
B	ISSUED FOR CLIENT REVIEW	06/26/12	SMW	MS	RF
A	ISSUED FOR INTERNAL REVIEW	06/26/12	SMW		

DRAWING APPROVAL

	SIGNATURE	DATE
DRAWN BY	SMW	
CHECKED BY		
IN HOUSE APPD.		
CLIENT APPD.		
CLIENT APPD.		

CLIENT PROJECT NUMBER	PROJECT NUMBER
	1110202

CHENIERE

PROJECT TITLE

CORPUS CHRISTI PIPELINE EXPANSION

Alliance Engineering
A Wood Group Company
F-3176

DWG. TITLE

PLOT PLAN EXHIBIT
SINTON COMPRESSOR STATION & TEJAS INTERCONNECT M&R STATION

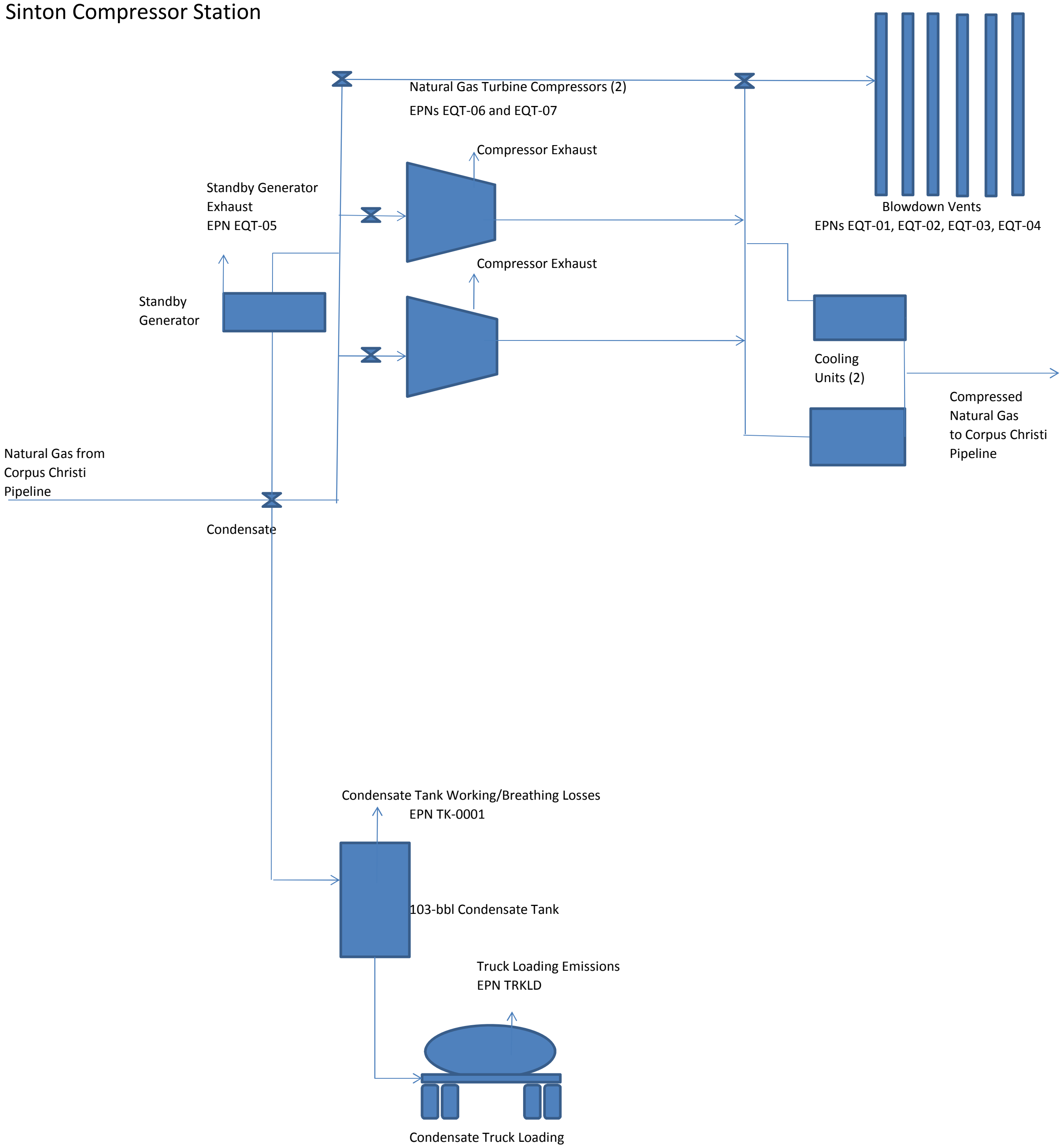
SCALE	DWG. NO.	REV.
1"=40'	11202800-04-05-450-0003	C

FILE PATH: K:\JOBS12\11202800.00\08_DELIVERABLES_WIP\08.05_CIVIL\04.05.450 SITE PREP-ROUGH GRADING\ISSUE\SINTON COMPRESSOR STATION & TEJAS M&R\REV C\SINTON COMPRESSOR STATION & TEJAS M&R DISTURBED AREA EXHIBIT.DWG BY: S1WICKE DATE: Jul 16, 2012 8:50am

FIGURE 3 – PROCESS FLOW DIAGRAM

Figure 3: Process Flow Diagram

Cheniere Corpus Christi Pipeline, L.P.
Sinton Compressor Station



APPENDIX A – CERTIFICATE OF GOOD STANDING

TEXAS COMPTROLLER OF PUBLIC ACCOUNTS

SUSAN COMBS • COMPTROLLER • AUSTIN, TEXAS 78774

August 22, 2012

CERTIFICATE OF ACCOUNT STATUS

THE STATE OF TEXAS
COUNTY OF TRAVIS

I, Susan Combs, Comptroller of Public Accounts of the State of Texas, DO HEREBY CERTIFY that according to the records of this office

CHENIERE CORPUS CHRISTI PIPELINE, L.P.

is, as of this date, in good standing with this office having no franchise tax reports or payments due at this time. This certificate is valid through the date that the next franchise tax report will be due November 15, 2012.

This certificate does not make a representation as to the status of the entity's registration, if any, with the Texas Secretary of State.

This certificate is valid for the purpose of conversion when the converted entity is subject to franchise tax as required by law. This certificate is not valid for any other filing with the Texas Secretary of State.

GIVEN UNDER MY HAND AND
SEAL OF OFFICE in the City of
Austin, this 22nd day of
August 2012 A.D.

Susan Combs

Susan Combs
Texas Comptroller

Taxpayer number: 32035185431
File number: 0800647652

Form 05-304 (Rev. 12-07/17)

APPENDIX B – BACT ANALYSIS

B. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

This section presents a BACT analysis for each of the pollutants emitted at the proposed Sinton Compressor Station that is subject to PSD review. In accordance with 40 CFR 52.21, regulations require new major stationary sources to conduct a BACT analysis for each emission unit with the potential-to-emit (PTE) a regulated NSR pollutant at a rate that would be greater than or equal to the significant emission rates identified in 40 CFR 52.21(b)(23).

BACT is defined as an achievable emission limitation based on the maximum degree of reduction while taking into account energy, environmental, and economic impacts and other costs on a case-by-case basis. The BACT analysis must separately address air pollution controls for each emissions unit or pollutant-emitting activity that emits a pollutant that is subject to PSD review.

BACT is defined in 40 CFR §52.21(b)(12) as:

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

The BACT analysis must demonstrate that a new major stationary source meets the applicable emission standards and standards of performance identified in 40 CFR Part 60 – *Standards of Performance for New Stationary Sources (NSPS)*, 40 CFR Part 61 – *National Emission Standards for Hazardous Air Pollutants (NESHAPS)* and 40 CFR Part 63 – *National Emission Standards for Hazardous Air Pollutants for Source Categories.*

B.1 PSD BACT Applicability

BACT applies to each new and modified emission unit, and is performed on a pollutant-by-pollutant basis. **Table B-1** lists the emission units and pollutants for which a PSD BACT analysis is required.

Table B-1
CCPL Emission Units and Pollutants Subject to BACT

EPN	Description	Source Type	Pollutants
EQT005	Standby Generator	Internal Combustion	NO_x CO $PM/PM_{2.5}/PM_{10}$ CO_2e
EQT006	Gas Turbine Driven Compressor Unit A	Internal Combustion	NO_x CO $PM/PM_{2.5}/PM_{10}$ CO_2e
EQT007	Gas Turbine Driven Compressor Unit B	Internal Combustion	NO_x CO $PM/PM_{2.5}/PM_{10}$ CO_2e
EQT001	Unit A Blowdown Stack	Blowdown Stack	CH_4 CO_2
EQT002	Unit B Blowdown Stack	Blowdown Stack	CH_4 CO_2
EQT003	Station Suction Blowdown Stack	Blowdown Stack	CH_4 CO_2
EQT004	Station Discharge Blowdown Stack	Blowdown Stack	CH_4 CO_2
FUG01	Fugitive Emissions	Process Fugitives	CH_4 CO_2

As discussed in Section 2.0, the proposed Sinton Compressor Station is a new major stationary source that has the potential to emit greater than 100,000 tpy of GHG on a CO_2e basis. Therefore, the facility is a major source for PSD purposes, and all proposed attainment pollutants emitted in amounts greater than or equal to the PSD SER are subject to PSD review.

B.2 BACT Analysis Methodology

EPA has developed a "top-down" process that can be used to ensure that BACT analysis satisfies the applicable legal criteria. The top-down method provides that all available control technologies are ranked in descending order of control effectiveness.[2] Based on the top-down examination, the most stringent control alternative is selected as BACT unless it can be demonstrated, and the permitting authority agrees, that the most stringent technology is not ‘achievable’ based on technical considerations, or energy, environmental, or economic impacts. If it is determined that the most stringent technology be eliminated as BACT, then the next most stringent technology is considered, and so on.[1] The five steps of the top-down method are described below:

Step 1 – Identify All Control Technologies

The first step is to identify, for each emission unit under BACT review, all available control options; where available control option means an air pollution control technology or technique with practical application to the emission unit and pollutant being reviewed in the BACT analysis.

For the purposes of this application, a search of nationally permitted control technology options was conducted using EPA’s RACT/BACT/LAER Clearinghouse (RBLC).

Step 2 – Eliminate Technically Infeasible Options

The second step of the BACT analysis is to consider the technical feasibility of each of the control options selected in Step 1 based on unit specific factors. The technical infeasibility of a control option should be based upon physical, chemical or engineering principals that would prevent the control option from being successfully implemented to the specific proposed emission unit. Also, each technology should be “demonstrated” (previously installed and operated successfully on a similar facility); or if undemonstrated, then the applicant must determine whether the technology is both “available” and “applicable.” Technologies identified in Step 1 that are neither demonstrated nor found to be both available and applicable are eliminated under Step 2. After technical infeasibility has been thoroughly demonstrated, the control option under review is eliminated from the BACT determination.

Step 3 – Rank Remaining Control Options By Effectiveness

Once technically infeasible control options have been eliminated from the BACT determination, the remaining control options are then ranked, in descending order, by control effectiveness. Information regarding control efficiency, emission rate, emission reduction and the impacts associated with environmental, economic and energy considerations should be documented. If the most stringent technology or technique available from the remaining technically feasible control options is proposed as BACT, economic and other detailed analysis for the alternative controls need not be considered further in the BACT analysis. If there is only one remaining option or if all of the remaining

[2] US EPA, “New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting.” (Oct., 1990).

technologies could achieve equivalent control efficiencies, ranking based on control efficiency is not required.

Step 4 – Evaluate Most Effective Controls and Document Results

Once the technically feasible control options have been identified, a BACT determination is made based on the energy, environmental and economic impacts. If the most stringent control option is proposed as BACT, then the direct impact of that option should be reviewed to determine if the next most stringent control option is more appropriate, and so on. The permitting authority (TCEQ) has discretion on weighting each area of collateral impact. This step validates the suitability of the top control option identified or provides a clear justification as to why the top option should not be selected as BACT. Costs of installing and operating control technologies are estimated and annualized following the methodologies outlined in the U.S. EPA's OAQPS Control Cost Manual (CCM).

Step 5 – Select BACT

Based on the control option review, conducted in the first four steps of the BACT analysis, the most effective control option remaining is proposed as BACT for the pollutant and emission unit under review.

B.3 BACT Summary

The results of the top-down BACT analysis conducted for all non-GHG pollutants under PSD review and for each applicable emission unit are summarized in **Table B-2.** BACT determinations were based upon technical feasibility, environmental impacts, energy impacts and economic impacts in accordance with TCEQ and EPA guidelines for conducting a top-down approach. Detailed analysis for each emission unit and each air pollutant required to undergo PSD review are provided in Section B.4 through Section B.6.

Table B-2
Proposed Non-GHG BACT Determinations for the CCPL

EPN	Pollutants	Control Option	Emission Limit
EQT006, EQT007	NO_x	Dry Low NO_X Burners and Good Combustion Practice	25 ppm @15% O_2
	CO	Good Combustion Practice	50 ppm @15% O_2
	$PM/PM_{2.5}/PM_{10}$	Good Combustion Practice and Burn Only Natural Gas	0.021 lb/MMBtu
EQT005	NO_x	Turbocharger, Intercooler, Good Combustion Practice, and limiting operating hours to 500 hours annually	2.0 g/hp-hr
	CO	Turbocharger, Good Combustion Practice, and limiting operating hours to 500 hours annually	1.8 g/hp-hr
	$PM/PM_{2.5}/PM_{10}$	Good Combustion Practice, use of pipeline natural gas, and limiting operating hours to 500 hours annually	0.000071 lb/MMBtu

B.4 GHG BACT

The GHG sources associated with the Project are summarized in **Table B-3**. As shown on **Table B-3**, the Project GHG sources emit GHG primarily via combustion or in the case of process streams, as fugitive emissions.

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

Table B-3
Project GHG Emission Sources

Equipment Type	GHG Source Type	Exhaust Type
Compression Turbines	Combustion Source	Stack
Standby Generator	Combustion Source	Stack
Fugitive Emissions	Process Source	Fugitive
Blowdown Stacks	Process Source	Stack

B.4.1 BACT Review Process

EPA's March 2011 GHG Permitting Guidance directed that a BACT review for GHGs should be done in the same manner as it is done for any other regulated pollutant.[3] EPA recommends that the 1990 Draft New Source Review Workshop Manual ("NSR Workshop Manual")[4] be used to determine BACT for PSD pollutants. According to this document, BACT determinations are made on a case by case basis using a "top-down" approach, with consideration given to technical practicability and economic reasonableness.

Since GHG BACT is a new and evolving requirement, the available tools and platforms are of limited use in preparing the GHG BACT analysis. Outside of the power generation industry, there are few examples of operational GHG control technologies specifically targeting control of GHGs. Since EPA is administering the program in Texas, CCPL reviewed applications on the Region 6 website that have been deemed complete as well as issued draft and final permits.

The overall control effectiveness of each control technology is characterized for the pollutant under review. The effectiveness evaluation includes a review of the expected emission rates and expected emission reductions. For GHGs, this ranking may be based on emission rates or energy efficiency. The control option with the highest effectiveness is the "top" control option. If the top control option is proposed by the permit applicant as BACT, no further evaluation is required. Otherwise, the process moves to Step 4.

With regard to carbon capture and sequestration ("CCS"), EPA recognizes in its BACT guidance for GHGs that "even if not eliminated at Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible."[5]

Permitting authorities have historically considered the effects of multiple pollutants in the application of BACT as part of the PSD review process, including the environmental impacts of collateral emissions resulting from the implementation of emission control technologies. To clarify the permitting agency's expectations with respect to the BACT evaluation process, states have sometimes prioritized the reduction of one pollutant above another. For example, technologies historically used to control NO_x emissions frequently caused increases in CO emissions. Accordingly,

[3] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* at p.17 (March 2011) ("GHG Permitting Guidance").
[4] EPA, New Source Review Workshop Manual - Prevention of Significant Deterioration and Nonattainment Area Permitting (Draft October 1990).
[5] GHG Permitting Guidance at 42-43.

several states prioritized the reduction of NO_x emissions above the reduction of CO emissions, approving low NO_x control strategies as BACT that result in elevated CO emissions relative to the uncontrolled emissions scenario. In this BACT analysis, there are instances of weighing the effectiveness of a control in reducing a GHG emission against the collateral impacts of that control.

The energy, environmental and economic impacts analysis under Step 4 of a GHG BACT assessment presents a unique challenge with respect to the evaluation of CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (e.g., flares and thermal oxidizers) actually convert CH_4 emissions to CO_2 emissions. Consequently, the reduction of one GHG (i.e., CH_4) results in a simultaneous increase in emissions of another GHG (i.e., CO_2). According to 40 CFR §52.21(b)(49)(ii), CO_2e emissions must be calculated by scaling the mass of each of the six GHGs by the gas' associated global warming potential (GWP), which is established in Table A-1 to Subpart A of 40 CFR Part 98. Therefore, to determine the most appropriate strategy for prioritizing the control of CO_2 and CH_4 emissions, CCPL considered each component's relative GWP.

Table B-4 provides the Global Warming Potential (GWP) for the three greenhouse gases expected to be emitted by the Sinton Compressor Station. The GWP is based on a 100-year time horizon. These data are taken from Table A-1 of 40 CFR Part 98.

Table B-4
Global Warming Potentials

Pollutant[1]	GWP[2]
CO_2	1
CH_4	21
N_2O	310

As presented in **Table B-4**, the GWP of CH_4 is 21 times the GWP of CO_2. Therefore, one ton of atmospheric CH_4 emissions has the same predicted global warming effect of 21 tons of CO_2e emissions. On the other hand, one ton of CH_4 that is combusted to form CO_2 emissions prior to atmospheric release equates to 2.7 tons of CO_2e emissions. Since the combustion of CH_4 decreases GHG emissions by approximately 87 percent on a CO_2e basis, combustion of CH_4 is preferential to direct emission of CH_4.

Establishing an appropriate averaging period for the BACT limit is a key consideration under Step 5 of the BACT process. As noted previously, localized GHG emissions are not known to cause adverse public health or environmental impacts. Since localized short-term health and environmental impacts from GHG emissions are not recognized, CCPL proposes only annual average GHG BACT limits in this application.

The BACT analysis provided below follows the traditional top-down approach; however, in accordance with 40 CFR 52.21(b)(7), conducting a separate analysis for each emissions unit or local grouping is a general recommendation. For new sources requiring PSD review the CAA and EPA provide discretion for the evaluation of BACT on a facility-wide basis for operations that affect the overall environmental performance of the facility.[6] For GHG specific considerations, it may be more appropriate to consider facility-wide or process-wide energy efficiency strategies to reduce GHG emissions from the proposed new source.[3] The application of methods or techniques to increase energy efficiency is crucial to reducing GHG emissions that falls under the category of 'lower-polluting processes/practices' identified in Step 1 of the top-down approach. Therefore, the availability of energy efficient operational strategies, alternative fuels and process improvements are also considered with the traditional add on control technology review.

B.4.2 CO_2 BACT

The emission sources of CO_2 at the proposed Sinton Compressor Station are as listed below:

- Turbines
- Standby Generator
- Blowdown Stacks

B.4.2.1 CO_2 BACT for Turbines

Identification of Potential CO_2 Control Technologies (Step 1)

The following potential CO_2 control strategies for the turbines were considered as part of this BACT analysis.

GHG Emission Reduction Measure	Description
Alternate Design – Electric Compressors	Use of electric-driven compressors; no related CO_2 emissions from the compressor
Carbon Capture and Storage (CCS)	Systems that capture CO_2 from the exhaust and transfer the CO_2 to permanent storage.
Low-Carbon Fuel	Use of lowest carbon fuel.

[6] US EPA (March, 2011) "PSD and Title V Permitting Guidance for Greenhouse Gases". http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

Eliminate Technically Infeasible Options (Step 2)

In the evaluation of technical feasibility presented below, of the five listed control options, the alternate design and CCS are considered technically infeasible for control of CO_2 emissions associated with the operation of the turbines. In addition to being technically infeasible, the use of electric compressors is not properly considered BACT because it would "redefine the source."

Alternate Design (use of electric-driven compressors)

Historically, EPA has not considered the BACT requirement as a means to redefine the design of a source when considering available control technologies. A control technology that would redefine the source may be eliminated at Step 1 of the top-down BACT analysis. The substitution of electric compressors at CCPL would redefine the source.

Carbon Capture and Storage

CCS is the only potential add-on control technology available to reduce the potential CO_2 emissions from the compression turbines. Per EPA permitting guidance, outlined in the *PSD and Title V Permitting Guidance for Greenhouse Gases*, CCS is "available for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for facilities with high-purity CO_2 streams (e.g. hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)".[7] First, CCS has not been installed and operated successfully (i.e., demonstrated) on a source similar to the proposed turbines. Second, although CCS is considered an "available" technology, as that term is used for the purpose of a PSD BACT analysis, because it has the potential for practical application to the control of CO_2 emissions from turbines, CCS is not "applicable" to the CCPL turbines because there is no specific evidence that there is a commercially available CCS system of the scale that would be required to control the CO_2 emissions from turbines in compressor service that are typical of those at the Sinton Compressor Station. In addition, the Sinton Compressor Station is a natural gas transmission station, with CO_2 emissions resulting from natural gas combustion. The natural gas being combusted in the turbines is pipeline quality gas; but would not produce a commercially viable high purity CO_2 stream.

This conclusion is supported by the *Report of the Interagency Task Force on Carbon Capture and Storage,* August 2010. The Task Force was composed of 14 Executive Departments and Federal Agencies and was co-chaired by the Department of Energy (DOE) and the Environmental Protection Agency (EPA). The purpose of the Task Force was to propose "a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within ten years." The Task Force report summarized

[7] US EPA (March, 2011) "PSD and Title V Permitting Guidance for Greenhouse Gases". http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.

the status of CCS technology, listed difficulties associated with implementing the technology, and stated that, although CCS technology is available, it is not ready for widespread implementation.

CCS technologies are developing, with several large scale demonstration projects underway at this time that may be relevant. The component elements of CCS (capture, transportation and storage) have all been demonstrated in various projects. However, CCPL has been unable to identify any gas turbines in compressor service fitted with flue gas carbon capture. CCPL did not identify a facility on which CCS had been successfully installed and operated for similar turbines. As shown below, CCPL has analyzed the economic feasibility of CCS in Step 4, despite the fact that it is not currently technically feasible for the turbines.

Rank of Remaining Control Technologies (Step 3)

In the third step of the top-down BACT analysis, the remaining options for turbine BACT are ranked. As explained in Step 2, CCS is not technically feasible for the turbines. Nevertheless, CCPL has chosen to carry it to Step 3 of the analysis in order to address the associated economic, energy, and environmental impacts in the next section.

Table B-5
Turbine CO_2 Control Rankings

Technology	Ranking	CO_2 Emission w/ Control, TPY
Carbon Capture and Storage	1	15,000 w/ 90% Control
Alternate Fuel*	2	150,000

* Assumes all three technologies are employed

<u>Carbon Capture and Storage</u>

For purposes of this analysis CCS, if it were technically feasible, would be considered the most effective control measure with an assumed 90% control effectiveness, based on the IGCC document Report of the Interagency Task Force on Carbon Capture and Storage, August 2010.

<u>Low Carbon Fuel</u>

For GHG BACT analyses, low-carbon intensity (mass of carbon per MMBtu) fuel selection is a control option that can be considered a lower emitting process. The turbines will be fired with pipeline quality natural gas. This is the cleanest and lowest-carbon fuel available for combustion in the turbines.

Evaluation of Most Stringent Controls (Step 4)

In Step 4 of this CO_2 BACT analysis, Carbon Capture and Storage (CCS) is evaluated with respect to cost and collateral impacts. All other technologies identified in Step 3 are proposed for use on the turbines and thus the Step 4 review is not required.

CCS Economic Evaluation

Notwithstanding its technical infeasibility, CCPL evaluated CCS on the basis of economic viability. Carbon capture and storage would require that the CO_2 in the turbine exhaust streams be captured, compressed and conveyed to a suitable long-term CO_2 storage facility. The economic feasibility of CCS has been evaluated based on the scrubbing method of CO_2 capture.

In addition to a CO_2 capture system, CCS would also require the installation of a large pipeline that would convey the captured CO_2 to an existing pipeline or to a suitable long-term CO_2 storage facility. Potentially suitable storage facilities include deep un-minable coal seams, deep saline formations, depleted oil basins, depleted gas fields, and oil fields where CO_2 can be injected for the purpose of enhanced oil recovery (EOR). No long-term CO_2 storage facilities are located near the CCPL Sinton Compressor Station. The Denbury Resources Green Pipeline, the nearest commercially available CO_2 pipeline, and the Denbury Resources West Hastings oil field where CO_2 could be used for EOR, are located approximately 160 miles from the Sinton Compressor Station.[8] Further evaluation of CCS is based on the assumption that the Denbury System will accept the captured CO_2 from this project.

CCPL has reviewed current cost information for CCS including the "Report of the Interagency Task Force on Carbon Capture and Storage," the U.S. Department of Energy National Energy Technology Laboratory (NETL)[9] document Based on these documents, annualized and capital costs of CCS have been developed.

Annualized Costs

The total annualized cost of CO_2 capture, transport and storage associated with the CCPL project is estimated to be $28 million.

Capital Cost

The capital cost of CCS for the CCPL project has been estimated to be $149 million, including approximately $56 million for CO_2 capture and approximately $93 million for a pipeline to connect to the Denbury pipeline. Storage analysis have not been included in this Step 4 analysis, based on the assumption that this CO_2 would be piped to an existing underground formation and the pipeline cost would include storage cost. This assumption builds additional conservatism into the analysis of economic impacts.

[8] Interstate Oil and Gas Compact Commission. (Sept, 2010) "A Policy, Legal, and Regulatory Evaluation of the Feasibility of a National Pipeline Infrastructure for the Transport and Storage of Carbon Dioxide". http://www.sseb.org/downloads/pipeline.pdf.

[9] NETL (March, 2010). "Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs". DOE/NETL-2010/1447.

Economic Infeasibility

In addition to the technical infeasibility of CCS for natural gas compression operations, the annualized costs and total capital investment make the implementation of CCS cost prohibitive for the Sinton Compressor Station.

Energy and Environmental Impacts

A CCS system would also cause significant adverse energy and environmental impacts. CO_2 capture systems require significant amounts of energy for their operation, which in turn reduce net plant efficiency. For larger facilities such as power plants, fuel consumption has been shown to increase between 11-40%.

In addition to natural gas pipeline standards, there are standards that must be met for CO_2 as well. Current standards, based largely on enhanced oil recovery (EOR), require low nitrogen content, while carbon capture systems do not. In addition, pipeline transport through highly populated areas requires detailed route selection, over-pressure protection and leak detection.

Selection of CO_2 BACT (Step 5)

CO_2 BACT for the turbines is the use of low-carbon fuels. Emissions from the two (2) Titan 130 combustion turbines (or equivalent) combusting only pipeline quality natural gas are estimated to be approximately 150,000 tons per year.

B.4.2.2 CO_2 BACT for Standby Generator

The standby generator will be an intermittent source that will be run for no more than 500 hours per year for standby power. CO_2 emissions from the generator are only 285 ton/yr. No additional add-on controls are proposed as BACT for CO_2 emissions from the generator; however, the standby generator will be controlled with good combustion practices, using manufactured operating recommendations, and will burn only pipeline quality natural gas. CO_2 BACT for the standby generator is the use of an efficiently designed and operated generator firing natural gas.

B.4.2.3 CO_2 BACT for Blowdown Stacks

The station suction and discharge blowdown stacks and unit blowdown stacks for the compression turbines are used in the event of process upsets. Based on RBLC search results there are no additional techniques available to reduce emissions of CO_2 from blowdown stacks located at natural gas compression stations. Therefore, no additional controls are being proposed for the blowdown stacks.

B.4.3 CH_4 BACT

The emission sources of CH_4 at the proposed Sinton Compressor Station are as listed below:

- Turbines
- Standby Generator
- Fugitive emissions
- Blowdown Stacks

B.4.3.1 CH_4 BACT for Turbines

Identification of Potential CH_4 Control Technologies (Step 1)

Control options for CH_4 emissions from the turbines include actual direct control, elimination of the capability to emit CH_4, and steps to minimize the generation of CH_4. Two methods were identified and were all carried to Step 2 in the process.

GHG Emission Reduction Measure	Description
Post-combustion catalytic oxidation	Provides rapid conversion of a hydrocarbon into CO_2 and water in the presence of available oxygen.
Burn low CH_4 generating fuel	Selection of a low CH_4 emitting fuel minimizes CH_4 emissions.

Eliminate Technically Infeasible Options (Step 2)

Post-Combustion Catalytic Oxidation

The turbine exhaust is expected to contain less than 1 ppmv CH_4. The exhaust gas CH_4 concentration is about two orders of magnitude below the lower end of VOC concentration in streams which would typically be fitted with catalytic oxidation for control.[10] Addition of post-combustion catalytic oxidation on the turbines for control of CH_4 is technically infeasible and will not be considered in subsequent steps of this analysis.

Burn Low CH_4 Generating Fuel

Based on the proposed operations for the Sinton Compressor Station, CCPL proposes to combust only pipeline quality natural gas in the compression turbines. Data collected by EPA and presented in Tables C-1 and C-2 of 40 CFR Part 98, Subpart C for purposes of estimating emissions of GHGs indicate that natural gas is among the lowest CH_4 emitting fuels available.

[10] US EPA, APTI 415, Control of Gaseous Emissions, Chapter 6, P 6-14. http://www.epa.gov/apti/Materials/APTI%20415%20student/415%20Student%20Manual/415_Chapter%206_final.pdf

Rank of Remaining Control Technologies (Step 3)

The only technically feasible remaining control option for reducing CH_4 emissions from the compression turbines is the use of a lower CH_4 emitting fuel. CH_4 emissions associated with combusting only pipeline quality natural gas are estimated to be no more than 2.82 tpy.

Evaluation of Most Stringent Controls (Step 4)

There are no adverse energy or environmental impacts associated with the remaining control technique.

Selection of CH_4 BACT (Step 5)

CH_4 BACT for the compression turbines is the firing of low-CH_4 generating fuel. CCPL has chosen to control CH_4 emissions by combusting only pipeline quality natural gas. Emissions from the two turbines, while combusting pipeline quality natural gas, are estimated to be no more than 2.82 tons per year.

B.4.3.2 CH_4 BACT for Standby Generators

The standby generators are intermittent sources that will be run for no more than 500 hours per year for standby power. CH_4 emissions from the generator are only 0.01 ton/yr. No additional add-on controls are proposed as BACT for CH_4 emissions from the generator; however, the standby generator will be controlled with good combustion practices, using manufactured operating recommendations, and will burn only pipeline quality natural gas. CH_4 BACT for the standby generator is the use of an efficiently designed and operated generator firing natural gas.

B.4.3.3 CH_4 BACT for Fugitive Emissions

There will be less than 10 tpy of CH_4 from the fugitive components at the site. CCPL is proposing to incorporate an annual infrared sensing plan to comply with the requirements of 40 CFR 60 Part 98.

Identification of Potential CH_4 Control Technologies (Step 1)

Based on the previously identified sources, four methods were identified and were all carried to Step 2 in the process.

GHG Emission Reduction Measure	Description
Leakless Technology Components	Replacement of traditional components with components designed for leakless operation
Leak Detection and Repair Program	Leak inspection programs that comply with state and federal regulations
Audio, Visual and Olfactory Programs	Supplemental inspection programs based on AVO sensing

Eliminate Technically Infeasible Options (Step 2)

Leakless Technology Components

Emissions from pumps and valves can be reduced through the use of leakless valves and sealless pumps. Common leakless valves include bellow valves and diaphragm valves, and common sealless pumps are diaphragm pumps, canned motor pumps and magnetic drive pumps. Leaks from pumps and compressors can also be reduced by using dual seals with or without barrier fluids.

Leakless valves and sealless pumps are effective at minimizing or eliminating leaks, but their use may be limited by materials of construction considerations and process operating conditions. Additionally, elevated service temperatures can have a negative effect on leakless components. For example, the tensile strength of bellow valves is degraded at higher process temperatures, which reduces the component life-cycle. Installing leakless and sealless equipment components is generally reserved for individual, chronic leaking components and specialized services. Additionally, leakless valves are primarily used where highly toxic materials are in service. Leakless technology components have not been widely adopted as BACT/LAER, and are not considered technically feasible on a facility-wide basis for the Sinton Compressor Station.

Leak Detection and Repair (LDAR) Programs

LDAR programs have been traditionally developed for control of VOC emissions. The fundamental elements for all LDAR programs include: identification of components to be included in the program, conducting routine instrument monitoring of identified components, repair of leaking components and reporting of the monitoring results. Monitoring direct emissions of CH_4 with traditional portable hydrocarbon monitoring equipment is technically feasible.

Audio/Visual/Olfactory (AVO) Monitoring Program

AVO monitoring can be used to detect leaking fugitive components. Natural gas leaks are expected to have discernible odors that are detectable by olfactory means. In addition, large leaks can be detected by audio and visual means, and secondary visual indications may include condensation around components suspected of leaking.

Rank of Remaining Control Technologies (Step 3)

In the third step of the top-down BACT analysis, the remaining options for turbine BACT are ranked. Based on the EPA's guidance in the *Protocol for Equipment Leak Emission Estimates*, LDAR programs have the potential to reduce hydrocarbon emissions from process fugitives by approximately 87%, representing the top control candidate.

Evaluation of Most Stringent Controls (Step 4)

No significant adverse energy or environmental impacts (that would influence the GHG BACT selection process) associated with the two technically feasible control options.

Selection of CH_4 BACT (Step 5)

CH_4 BACT for the fugitive sources is the proposed LDAR program. Based on RBLC search results, an LDAR program represents the LAER control option. While a top-down BACT analysis also requires that LAER control candidates are included in the control candidate review, they are not strictly required in areas that demonstrate attainment. Currently, San Patricio County is classified as an attainment or unclassifiable area for all pollutants. Therefore, CCPL proposes to conduct annual GHG surveys in compliance with 40 CFR 60 Part 98 for stand-alone compression stations.

B.4.3.4 CH_4 BACT for Blowdown Stacks

The station suction and discharge blowdown stacks and unit blowdown stacks for the compression turbines are used in the event of process upsets. Based on RBLC search results there are no additional techniques available to reduce emissions of CH_4 from blowdown stacks located at natural gas compression stations. Therefore, no additional controls are being proposed for the blowdown stacks.

B.4.4 N_2O BACT

The emission sources of N_2O at the proposed Sinton Compressor Station are as listed below:

- Turbines
- Standby Generators

B.4.4.1 N_2O BACT for Turbines

Identification of Potential N_2O Control Technologies (Step 1)

The following control options for N_2O emissions from the turbines were considered as part of the BACT process.

GHG Emission Reduction Measure	Description
N_2O catalysts	Decompose N_2O into nitrogen and oxygen
Burn low N_2O generating fuel	Selection of a low N_2O -emitting fuel minimizes N_2O emissions.

Eliminate Technically Infeasible Options (Step 2)

N_2O catalysts have been used to reduce N_2O emissions from adipic acid and nitric acid plants.[11] There is no indication that these catalysts have been used to control N_2O emissions from turbine flue gas. In addition, the very low N_2O concentrations (<1 ppm) present in the exhaust stream would make installation of N_2O catalysts technically infeasible. In comparison, the application of a catalyst in the nitric acid industry sector has been effective due to the high (1,000-2,000 ppm) N_2O concentration in those exhaust streams. N_2O catalysts are eliminated as a technically feasible option for the proposed project.

Rank of Remaining Control Technologies (Step 3)

The only remaining technically feasible control option for controlling emissions of N_2O from the compression turbines is fuel selection. N_2O emissions for the compression turbines are estimated to be no more than 0.28 tpy, when firing only pipeline quality natural gas.

Evaluation of Most Stringent Controls (Step 4)

No significant adverse energy or environmental impacts are associated with the remaining control option.

Selection of N_2O BACT (Step 5)

CCPL has chosen to control N_2O emissions by combusting only pipeline quality natural gas in the compression turbines. Emissions from the two turbines combined with incorporation of natural gas combustion are estimated to be no more than 0.28 tons per year.

B.4.4.2 N_2O BACT for Standby Generators

The standby generators are intermittent sources that will be run for no more than 500 hours per year for standby power. N_2O emissions from the generator are less than 0.01 tpy. No additional add-on controls are proposed as BACT for N_2O emissions from the generator; however, the standby generator will be controlled with good combustion practices, using

11 http://www.catalysts.basf.com/p02/USWeb-Internet/catalysts/e/content/microsites/catalysts/news/success-stories/reduce-emissions

manufacturer operating recommendation and burn only pipeline quality natural gas.

B.5 Criteria Pollutant BACT Analysis – Combustion Turbines

This section provides a pollutant-by-pollutant BACT determination for the Titan 130-20502S or equivalent gas turbines (EPNs EQT006 and EQT007) proposed for the Sinton Compressor Station. CCPL is proposing to install two (2) simple-cycle gas turbines with lean-premix annular-type combustion (SoLoNO$_x$) for natural gas compression. These emission units are simple-cycle turbines that combust only natural gas. It is anticipated that these units will be operated within their defined operating range as pipeline operating conditions demand. This range exists between the surge limit and the horsepower limit and will vary depending on pipeline pressure and flow. Because these gas turbines will be used for gas compression, they will have variable operating characteristics and hotter exhaust temperatures and cannot be compared to turbines used in electric generation. CCPL anticipates that these turbines will only be taken offline for planned maintenance startup and shutdown (MSS) events. Manufacturing estimates indicate that each shutdown event for the turbine requires 15 minutes and each startup event requires 15 minutes. Based upon process knowledge, CCPL anticipates that no more than one-hundred (100) planned MSS events per turbine will be required annually.

B.5.1 Nitrogen Oxide Formation

NO$_X$ formation occurs by three fundamentally different mechanisms. The principal mechanism of NO$_X$ formation in natural gas combustion is thermal NO$_X$. The thermal NO$_X$ mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air.[12] The formation of thermal NO$_X$ is affected by three furnace-zone factors: (1) oxygen concentration, (2) peak temperature, and (3) time of exposure at peak temperature. As these three factors increase, NO$_X$ emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural gas fired combustion. Emission levels vary considerably with the type and size of the combustor and with operating conditions (*e.g.*, combustion air temperature, volumetric heat release rate, load, and excess oxygen level).

The second mechanism, called prompt NO$_X$, is formed from early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO$_X$ forms within the flame and is usually negligible when compared to the amount of thermal NO$_X$ formed.[2]

[12] US EPA. Emissions Standards Division “Alternative Control Techniques Document – NO$_x$ Emissions from Stationary Gas Turbines (EPA-453/R-93-007).” (Jan, 1993). http://yosemite1.epa.gov/ee/epa/ria.nsf/vwAN/A9346.pdf/$file/A9346.pdf.

The third mechanism, fuel NO_X, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Natural gas has negligible chemically-bound fuel nitrogen.

B.5.2 NO_X Control Candidates – Combustion Turbines

Based upon a search of nationally permitted control technology options conducted using EPA's RACT/BACT/LAER Clearinghouse (RBLC), the following control options are available control candidates for simple-cycle turbines combusting natural gas:

- *Wet Controls - Water and Steam Injection;*
- *Dry Low NO_X (DLN) Combustor Technology;*
- *Selective Catalytic Reduction (SCR); and*
- *Selective Non-Catalytic Reduction (SNCR).*

Additional control candidates available to control NO_x emissions from simple-cycle turbines, not listed in the EPA's Technology Transfer Network, include the following:

- *Rich/Quench/Lean (RQL) Combustion;*
- *Catalytic Combustion – Xonon™;*
- *EMxGT Catalytic Oxidation/Absorption; and*
- *Alternate Lower FBN (fuel-bound nitrogen) Fuels.*

B.5.2.1 Wet Controls – Water and Steam Injection

Water and steam injection directly into the flame area of the turbine combustor provides a heat sink that lowers the flame temperature and reduces thermal NO_X formation; however, fuel NO_X formation is not reduced with this technique. The water or steam injection rate is typically described on a mass basis by a water-to-fuel ratio (WFR) or steam-to-fuel ratio (SFR). Higher WFRs and SFRs translate to greater NO_X reductions, but may also cause potential flame outs, increasing maintenance requirements and reducing turbine efficiency. During startup and shutdown events for the simple-cycle turbines, introduction of water or steam injection into the proposed DLN combustors while firing natural gas would cause severe disruption to combustion dynamics and would likely result in damage to the combustion system and related components. Based on discussions with Solar, water or steam injection aren't commercially available options for the proposed design. Accordingly, the use of water or steam injection during natural gas-fired operations will be precluded from further considerations in this BACT analysis for EPNs EQT006 and EQT007.

B.5.2.2 Dry Low NO_X (DLN) Combustion Technology

DLN combustion control techniques reduce NO_X emissions without the use of water or steam injection. Two DLN combustion designs are available: lean pre-mixed combustion and rich/quench/lean staged combustion (discussed in Section B.5.2.3). Historically, gas turbine combustors were designed for operation with unit (1) primary zone equivalence ratios (an equivalence ratio of one indicates a stoichiometric ratio of fuel and air). However, with fuel-lean combustion (sub-stoichiometric conditions), the additional excess air cools the flame and reduces the rate of thermal NO_X formation. With reduced residence time combustors, dilution air is added sooner than with standard combustors resulting in the combustion gases attaining a high temperature for a shorter time, thus reducing the rate of thermal NO_X formation. Pilot flames are used to maintain combustion stability to maintain the fuel-lean conditions. The proposed simple-cycle turbines at the Sinton Compressor Station are implemented with the Solar Turbines, Inc. SoLoNO_X or equivalent design which is a DLN combustion technology that utilizes lean pre-mixed combustion. <u>Therefore, this combustion design technique will be included in further BACT determinations.</u>

B.5.2.3 Rich/Quench/Lean (RQL) Combustion Technology

RQL combustors burn fuel-rich in the primary zone and fuel-lean in the secondary zone and reduce both thermal and fuel NO_X. Incomplete combustion under fuel-rich conditions in the primary zone produces an atmosphere with a high concentration of CO and H_2, which replace some of the oxygen for NO_X formation and also act as reducing agents for any NO_X formed in the primary zone. Based on available rig test results, this control alternative is more effective for higher fuel-bound nitrogen fuels in retarding the rate of fuel NO_X formation. Theoretically, this control alternative is applicable to natural gas-fired turbines; however, based on information presented in the EPA ACT (Alternative Control Techniques) document, RQL combustors are not commercially available for most turbine designs, and there is no known application for only natural gas-fired simple-cycle combustion turbines. <u>Because it is not technically feasible and unproven in practice, RQL combustion will be precluded from further consideration in this BACT determination for EPNs EQT006 and EQT007.</u>

B.5.2.4 Add-on Controls: Selective Catalytic Reduction (SCR)

In the SCR process, ammonia (NH_3), usually diluted with air or steam, is injected through a grid system into the flue/exhaust gas stream upstream of a catalyst bed. On the catalyst surface, the NH_3

reacts with NO_X to form molecular nitrogen and water. The basic reactions are as follows:

$$4NH_3 + 4NO + O_2 = 4N_2 + 6H_2O$$

$$8NH_3 + 6NO_2 = 7N_2 + 12H_2O$$

The reactions take place on the surface of a catalyst. Usually, a fixed bed catalytic reactor is used for the SCR process. The function of the catalyst is to effectively lower the activation energy of the NO_X decomposition reactions. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, and design of the ammonia injection system.

Depending on system design and the inlet NO_X level, NO_X removal of approximately 80 percent is achievable. The reaction of NH_3 and NO_X is favored by the presence of excess oxygen. Another variable affecting NO_X reduction is exhaust gas temperature. The greatest NO_X reduction occurs within a reaction window at catalyst bed temperatures between 400°F and 800°F for base metal catalyst types (i.e., conventional SCR applications with lower temperature range platinum catalysts and with higher temperature range 550°F-800°F vanadium-titanium catalysts).

However, base metal catalysts deteriorate quickly when continuously subjected to temperatures above this range or under thermal cycling, which commonly occurs in turbines in gas compression service. In effect, if these catalyst systems are operated beyond their specified temperature ranges, oxidation of the ammonia to either additional nitrogen oxides or ammonium nitrate may result. Moreover, the variable load demands on turbines in gas compression services create significant operational complexities for use of SCRs. A current review of the RBLC BACT Clearinghouse indicated that there are no simple-cycle turbine applications in gas compression utilizing SCR. SCR is therefore unproven in this application, and its use here would present significant complexity and reliability issues. <u>Therefore, SCR is considered technically infeasible.</u>

B.5.2.5 Add-on Controls: Selective Non-Catalytic Reduction (SNCR)

SNCR technology involves using ammonia or urea injection similar to SCR technology but at a much higher temperature window of 1,600°- 2,200°F. The following chemical reaction occurs without the presence of a catalyst:

$$NO_X + NH_3 + O_2 + H_2O + (H_2) \rightarrow N_2 + H_2O$$

The operating temperature can be lowered from 1,600°F to 1,300°F by injecting readily-oxidizable hydrogen with the ammonia. However, beyond the upper temperature limit, the ammonia is converted to NO_X, resulting in increased NO_X emissions.

Because the exhaust temperatures in gas turbines typically do not exceed 1,250°F, the operative temperature window of this control alternative is not technically feasible for this application. Exhaust temperatures for the proposed gas turbines (EPNs EQT006 and EQT007) are approximately 900 °F, which is well below the range for SNCR applications. In addition, this technology has a residence time requirement of 100 milliseconds, which is relatively slow for gas turbine operating flow velocities. Thus, adequate residence time for the NO_X destruction chemical reaction will not be available.

Further, a review of the RBLC database for recent BACT/LAER determinations for this particular source category and discussions with control system vendors do not indicate that SNCR systems have been successfully installed for NO_X control for similar simple-cycle turbines. <u>In view of the above limitations in utilizing SNCR control, this control alternative is not considered technically feasible and will be precluded from further consideration in this BACT determination for EPNs EQT006 and EQT007.</u>

B.5.2.6 Add-on Controls EMxGT (formerly SCONO$_X$™) Catalytic Oxidation/ Absorption

This is a catalytic oxidation/absorption technology that has been applied for concomitant reductions of NO_X, CO, and VOC from an assortment of combustion applications that mostly include small turbines, boilers, and lean-burn engines. Note that EMxGT technology is being assessed in this BACT determination as an add-on control option to DLN since it is a competitive technology with SCR.

EMxGT employs a single catalyst for converting NO_X, CO, and VOC. The flue gas temperature should be in the 300°F-700°F range for optimal performance without deleterious effects on the catalyst assembly. The technology was developed as a foil to traditional SCR applications that use ammonia resulting in additional operational safeguards, unfavorable environmental impacts, and excessive costs. In the initial oxidation cycle, CO is oxidized to CO_2, NO is converted to NO_2 and VOC is oxidized to carbon dioxide and water. The NO_2 is then absorbed on the potassium carbonate coated (K_2CO_3) catalyst surface forming potassium nitrites and nitrates (KNO_2, KNO_3). Prior to saturation of the catalyst surface, the catalyst enters the regeneration cycle.

In the regeneration phase, the saturated catalyst section is isolated with the expedient of moving hinged louvers and then exposed to a dilute reducing gas (methane in natural gas) in the presence of a carrier gas (steam) in the absence of oxygen. The reductant in the regeneration gas reacts with the nitrites and nitrates to form water and elemental nitrogen. Carbon dioxide in the regeneration gas reacts with potassium nitrites and nitrates to recover the potassium carbonate, which is the absorber coating that was on the surface of the catalyst before the oxidation / absorption cycle begins. Water (as steam) and elemental nitrogen are exhausted up the stack and the re-deposited K_2CO_3 allows for another absorption cycle to begin.

EMxGT technology is a variation of traditional SCR technology and for optimal performance it makes similar demands such as stable gas flows, lack of thermal cycling, invariant pollutant concentrations, and residence times on the order of 1-1.5 seconds. However, the benefit of not using ammonia has been replaced by other potential operational problems that impair the effectiveness of the technology. Therefore, this technology is being removed as BACT due to concerns regarding technical feasibility. Incorporation of an EMxGT system for control of emissions from CCPL's turbine systems faces the following technical concerns:

- Scale-up is still an issue. The technology has not been demonstrated for larger turbines and the vendor's contention is still being debated;
- The technology is not readily adaptable to high-temperature applications outside the 300°-700°F range and is susceptible to potential thermal cycling; As described above, the exhaust temperature for the proposed turbines is approximately 900 °F and therefore above the optimal range of this control technology.
- The prospect of moving louvers that effect the isolation of the saturated catalyst readily lends itself to the possibility of thermal warp and in-duct malfunctions in general. The process is dependent on numerous hot-side dampers that must cycle every 10 to 15 minutes. Directional flow solutions are not yet known to have been implemented for this technology;
- The K_2CO_3 coating on the catalyst surface is an active chemical reaction and reformulation site, which makes it particularly vulnerable to fouling. On some field installations, the coating has been found to be friable and tends to foul in the harsh in-duct environment;

- During the regeneration step, the addition of the flammable reducing gas (natural gas which contains ~93% methane) into the hot flue gas generates the possibility of LEL (lower explosive limit) exceedances in the event the catalyst isolation is not hermetic or if there is a failure in the carrier steam flow; and
- There is a possibility of some additional SO_2 emissions if the dry scrubber with the tandem "guard-bed" EMxGT unit experiences a malfunction.

In addition to the effective technical applicability and operational issues discussed above, there are also significant energy impacts associated with the application of EMxGT technology. There is a fuel penalty associated with the use of the catalyst. The increased backpressure in the turbine from the catalyst installation increases the heat input required and reduces the power output of the turbine. Additionally, a current review of the RBLC BACT Clearinghouse indicated that there are no simple-cycle turbine applications utilizing EMxGT. <u>In view of the above limitations in utilizing EMxGT, this control alternative is precluded from further consideration in this BACT determination for EPNs EQT006 and EQT007.</u>

B.5.2.7 Add-on Controls: Catalytic Combustion – XONON™

Xonon™ is a catalytic combustion technology in development that reduces the production of NO_X. The technology has only been tested on small turbines (less than 10 MW) and it is still not commercially available for the proposed simple-cycle turbines.

In a catalytic combustor, the fuel and air are premixed into a fuel-lean mixture and then passed into a catalyst bed. In the bed, the mixture oxidizes without forming a high-temperature flame front, thereby reducing peak combustion temperatures below 2,000ºF, which is the temperature at which significant amounts of thermal NO_X begin to form. The catalyst manufacturer has indicated that gas turbines retrofitted with the Xonon™ catalyst emit NO_X levels below 3 ppm.[13] However, until such time that the technology is commercially available, catalytic combustors are not considered technically feasible. In addition, discussions with Solar indicated that this technology is not commercially available for any Solar product. <u>In view of the above limitations in utilizing catalytic combustor control, this control alternative is precluded from further consideration in BACT determinations for EQT006 and EQT007.</u>

[13] US EPA. *Emissions Factors & AP-42, Compilation of Air Pollutant Emission Factors*. (Apr, 2000). http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf.

B.5.2.8 Alternate Lower FBN (Fuel-Bound Nitrogen) Fuels

The utilization of a lower FBN fuel such as coal-derived gas or methanol is not deemed practical based on the nature of the proposed operations at the Sinton Compressor Station. Thus, this control alternative is not addressed further in this BACT determination.

B.5.3 NO_X BACT Impact Analysis for Combustion Turbines

As previously mentioned, seven of the eight proposed NO_X control technologies are either technically infeasible or have not been demonstrated in practice for a comparably sized simple-cycle gas turbine. The remaining approach, DLN combustion, is already being utilized at other compressor stations for control of NO_X during normal operations as well as startup and shutdown events for simple-cycle turbines.

B.5.4 NO_X BACT Determination – Combustion Turbines

As DLN constitutes the only feasible NO_X control option, CCPL proposes that the SoLoNO$_X$ lean-premix turbines represent the top level BACT for the proposed Sinton Compressor Station. The proposed NO_X emission rates for the simple-cycle turbines are 25 ppmvd at 15% O_2. CCPL will demonstrate compliance using performance testing. CCPL plans utilize the continuous parameter monitoring option in 40 CFR 60 Subpart KKKK, for each of the combustion turbines. The details of the BACT compliance demonstration for the combustion turbines are provided in Section B.5.5. Additionally, turbine manufacturers report no significant performance impacts for lean-premix or ultra-lean-premix combustors and there is no additional energy or environmental impacts.

Table B-6
Turbine NO_x Emission Limit Requirements

EPN	BACT	Proposed NO_X Emission Limit
EQT006	DLN Combustion and Good Combustion Practice	25 ppm @15% O_2
EQT007	DLN Combustion and Good Combustion Practice	25 ppm @15% O_2

B.5.5 NO_X BACT Compliance Demonstration – Combustion Turbines

CCPL is proposing lean-premix DLN combustion design for the Titan 130-20502S or equivalent simple-cycle turbines as BACT. These units will be operated in accordance with 40 CFR 60 Subpart KKKK and all applicable regulations incorporated by reference.

CCPL will meet the NO_X emissions standards for both turbines (new turbines firing natural gas >50MMBtu/hr and <=850MMBtu/hr). CCPL will operate and maintain EPNs EQT006 and EQT007 in a manner consistent with good air pollution control practices for minimizing emissions at all times, including during startup, shutdown and malfunction.

B.5.6 Carbon Monoxide Formation

CO emissions form primarily as the result of incomplete combustion. Available emissions data indicate that the turbine's operating load has a considerable effect on the resulting emission levels. Gas turbines are typically operated at high loads (greater than or equal to 80% of rated capacity) to achieve maximum thermal efficiency and peak combustor zone flame temperatures. With reduced loads, or during periods of frequent load changes, the combustor zone flame temperatures are expected to be lower than the high load temperatures, yielding lower thermal efficiencies and more incomplete combustion. CO results when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation. The oxidation of CO to CO_2 at gas turbine temperatures is a slow reaction compared to most hydrocarbon oxidation reactions. In gas turbines, failure to achieve CO burnout may result from quenching by dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. CO emissions are also dependent on the loading of the gas turbine.

B.5.7 CO Candidate Controls – Combustion Turbines

Based upon a search of nationally permitted control technology options conducted using the RBLC Clearinghouse, the following control options are available control candidates for simple-cycle turbines combusting natural gas:

- *Combustion Control; and*
- *CO Oxidation Catalysts.*

As with NO_X, CO is emitted during startup and shutdown events at rates that are typically higher than what is experienced during normal operation, which is a result of how the combustion turbine transitions through the partial load conditions on its way to normal operating load. However, performance of the considered emission control techniques is generally similar for startup and shutdown events as it is for normal operation, though some technologies may be more or less effective depending on their particular mode of operation.

The previously listed information resources were consulted to determine the extent of applicability of each identified control alternative.

B.5.7.1 Combustion Control

Because CO is essentially a by-product of incomplete or inefficient combustion, it is important that combustion control constitutes the primary mode of reduction of CO emissions. The lean combustion control technology to be incorporated in the gas turbines for the Sinton Compressor Station has already been discussed in detail. The Solar Turbine DLN combustor technology for EPNs EQT006 and EQT007 not only ensures significant NO_x reductions but also compensates for CO emissions.

The basic premise of the technology involves premixing the fuel and air prior to entering the combustion zone, which provides for a uniform fuel/air mixture and prevents local hotspots in the combustor, thereby reducing NO_x emissions. However, the residence time of the combustion gases in these lean premixed combustors must be increased to ensure complete combustion of the fuel to minimize CO emissions.

The Sinton Compressor Station incorporates combustion controls to reduce CO emissions concomitantly with NO_x emissions. A review of the RBLC database shows that combustion control is the primary means of reducing CO emissions for similarly sized natural gas-fired turbines. <u>Therefore, combustion control will be considered further in the BACT analysis as a viable control technique.</u>

B.5.7.2 CO Oxidation Catalyst

Theoretically, a CO oxidation catalyst could reduce CO emissions from a simple-cycle turbine in gas compression service. The optimal working temperature range for CO oxidation catalysts is approximately 450°F to 850°F. Careful placement considerations are needed to achieve effective operational efficiency. The CO catalyst must be strategically placed within the proper turbine exhaust lateral distribution to evenly distribute the gas flow across the catalyst. Reduction of CO is possible during startup and shutdown events, but at lower efficiencies compared to normal operation, due to the lower exhaust gas temperatures relative to normal operation.

Oxidation catalyst systems serve to remove CO from the turbine exhaust gas rather than limiting pollutant formation at the source. The technology does not require introduction of additional chemicals for the reaction to proceed. The oxidation of CO to CO_2 uses the excess air present in the turbine exhaust, and the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. CO oxidation catalyst is not technically feasible for the simple-cycle turbines proposed for the Sinton Compressor Station, which will generally have an exhaust temperature of approximately 900^0F, greater than the typical operating range of 450-850°F. Vendors have developed CO oxidation catalysts with higher temperature operating ranges; however a review of the RBLC indicated that no current PSD compressor station is utilizing CO oxidation catalysts. Therefore the reliability and effectiveness of these higher-temperature catalysts are undemonstrated for compressor stations.

B.5.8 CO BACT Impact Analysis for Combustion Turbines

The technically feasible BACT control options for reduction of CO emissions from the simple-cycle gas turbines is combustion control.

B.5.9 CO BACT Determination – Combustion Turbines

CCPL proposes to use combustion control, inherent in the proposed manufacturer's DLN technology, as BACT for the compressor turbines.

B.5.10 CO BACT Compliance Demonstration – Combustion Turbines

CCPL proposes to use combustion controls, inherent with $SoLoNO_x$, to control emissions of CO. The proposed CO emission rates for the simple-cycle turbines are 50 ppmvd at 15% O_2. CCPL will demonstrate compliance using performance testing. There are no standards for CO in 40 CFR 60 Subpart KKKK; however, CCPL will operate the combustion turbines in accordance with good combustion practices and manufacturer recommendations in order minimize emissions of CO.

Table B-7
Turbine CO Emission Limit Requirements

EPN	BACT	Proposed CO Emission Limit
EQT006	DLN Combustion and Good Combustion Practice	50 ppm @15% O_2
EQT007	DLN Combustion and Good Combustion Practice	50 ppm @15% O_2

B.5.11 PM/PM_{10}/$PM_{2.5}$ Formation – Combustion Turbines

PM emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions are negligible with natural gas firing. PM emissions can be classified as "filterable" or "condensable". Filterable PM is that portion of the total PM that exists in the stack in either solid or liquid state and can be measured on an EPA Method 5 filter. Condensable PM is that portion of the total PM that exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter. Condensable PM exists as a gas in the stack, so it passes through the Method 5 filter and is typically measured by analyzing the impingers, or "back half" of the sampling train. The collection, recovery, and analysis of the impingers are described in EPA Method 202 of Appendix M, Part 51 of the Code of Federal Regulations. Condensable PM is composed of organic and inorganic compounds and is generally considered to be all less than 1.0 micrometers in aerodynamic diameter. As such, BACT for $PM_{2.5}$ will also constitute BACT for PM and PM_{10}.

B.5.12 $PM_{2.5}$ Candidate Control – Combustion Turbines

Based on a technical review using the previously identified sources, the available control technologies for reduction of potential emissions of $PM_{2.5}$ from the combustion turbines are provided below:

- *Good combustion practice; and*
- *Natural gas fuel.*

B.5.13 $PM_{2.5}$ BACT Impact Analysis – Combustion Turbines

CCPL is proposing to use good combustion practice while burning only pipeline quality natural gas. Therefore, no additional ranking is necessary. In addition, there are no adverse economic, environmental or energy impacts associated with the available control candidates.

B.5.14 $PM_{2.5}$ BACT Determination – Combustion Turbines

Based on the review for viable control options, the only available emissions control for the simple-cycle turbines (EPNs EQT006 and EQT007) is good combustion practice and burning only pipeline quality natural gas. Good combustion practices involve proper operation and maintenance of the turbines (EPNs EQT006 and EQT007). Therefore, CCPL has determined that good combustion practice and natural gas fuels are BACT for reduction of $PM_{2.5}$ from both the simple-cycle gas turbines. Creating and maintaining operating procedures as well as proper training are the best ways to ensure these criteria are being met. The Sinton Compressor Station will keep operating logs for startup, shutdown, and maintenance as well as normal operations in accordance with good combustion practices. Maintenance logs will also be kept to ensure the turbines are in good condition. In addition, CCPL will fire only pipeline quality natural gas.

Table B-8
Turbine $PM_{2.5}$ Emission Limit Requirements

EPN	BACT	Proposed $PM_{2.5}$ Emission Limit
EQT006	Good Combustion Practice	0.021 lb/MMBtu
EQT007	Good Combustion Practice	0.021 lb/MMBtu

B.6 Criteria Pollutant BACT Analysis – Standby Generator

This section provides a pollutant-by-pollutant BACT determination for the Waukesha VHP5904LTD or equivalent standby generator (EPN EQT005) proposed for the Sinton Compressor Station. CCPL is proposing to install a standby generator for standby electricity generation to power the facility. This emission unit is a spark-ignited lean-burn internal combustion (IC) engines, combusting only natural gas. The unit has a horsepower rating of 1,328 brake horsepower (bhp). It is anticipated that this unit will operate at 100% load capacity for no more than 500 non-emergency hours annually. The results of the BACT analysis for EPN EQT005 are provided in Sections B.6.1 through B.6.7.

B.6.1 NO_x Candidate Controls – Standby Generator

From a search of the RBLC clearinghouse, the technologies available to potentially control NO_x emissions from the IC engines include the following:

- *Turbocharger*
- *Timing Retard*

Additional potential technologies for the control of NOx from the standby generator include

- *Non Selective Catalytic Reduction (NSCR); and*
- *SCR.*

The technical feasibility for these control candidates is discussed in Sections B.6.1.1 through B.6.1.4.

B.6.1.1 Turbocharger and Aftercoolers

Installation of a turbocharger and aftercoolers/intercooler can reduce NOx emissions. The proposed standby generator contains both an Intercooler and a turbocharger and thus this control technology is considered technically feasible.

B.6.1.2 Timing Retard

By adjusting the timing retard, the air-fuel mixture can be regulated to reduce NOx emissions. This effectively de-rates the engine and reduces peak power available from the engine. Since this unit is designated as a standby unit, this would reduce the availability of peak power during emergency situations. As such, this control technology is considered technically infeasible.

B.6.1.3 Selective Catalytic Reduction

The SCR process for IC engines is fundamentally the same as for turbines. In the SCR process, ammonia (NH_3) or urea, usually diluted with air or steam, is injected through a grid system into the flue/exhaust gas stream upstream of a catalyst bed. On the catalyst surface the NH_3 and excess oxygen react to reduce NO_x to nitrogen and water. The basic reactions are as follows:

$$4NH_3 + 4NO + O_2 = 4N_2 + 6H_2O$$
$$8NH_3 + 6NO_2 = 7N_2 + 12H_2O$$

The reactions take place on the surface of a catalyst. Usually, a fixed bed catalytic reactor is used for the SCR process. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reactions. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, and design of the ammonia injection system.

Depending on system design and the inlet NO_x level, NO_x removal of up to 70-90 percent and higher is achievable at optimum theoretical conditions. The reaction of NH_3 and NO_x is favored by the presence of excess oxygen. Another variable affecting NO_x reduction is exhaust gas temperature. The greatest NO_x reduction occurs within a reaction window at catalyst bed temperatures between 400°F and 800°F for base metal catalyst types (i.e., conventional SCR applications with lower temperature range platinum catalysts and with higher temperature range 550°F-800°F vanadium-titanium catalysts). However, base metal catalysts deteriorate quickly when continuously subjected to temperatures above this range. In effect, if these catalyst systems are operated beyond their specified temperature ranges, oxidation of the ammonia to either additional nitrogen oxides or ammonium nitrate may result. The exhaust temperature for the standby generator (EQT005) is approximately 860°F, which is above the temperature range for the vanadium-titanium catalysts. Additionally, this unit is only used to provide power in emergency situations and is otherwise limited to 500 hours of operation annually. Therefore, this technology is considered technically not feasible for the standby generator (EPN EQT005).

B.6.1.4 Non Selective Catalytic Reduction (NSCR)

NSCR utilizes a three-way catalyst to promote the reduction of NO_x to nitrogen and water, while oxidizing CO and hydrocarbons (HC) to carbon dioxide and water. This control technology is applicable only to rich-burn IC engines, as lean-burn IC engine exhaust does not contain sufficient CO and HC to promote the reduction of NO_x. CCPL has selected to operate a 4-stroke lean-burn IC engine; therefore, NSCR is technically not feasible for EPN EQT005.

B.6.2 Selection of NOx BACT – Standby Generator

The only proposed NOx control technologies that is technically feasible for lean-burn IC engine standby generating units is a turbocharger with intercooler/aftercooler. As noted above, the proposed standby engine already incorporates this technology. Therefore, CCPL proposes that these, good combustion practice, and limiting the operating hours for the standby generating unit (EPNs EQT005) to 500 hours per year constitute BACT for the standby generator. By limiting the yearly operating hours and utilizing good combustion practice with only natural gas fuel, the emissions of NO_x will be limited to 2.0 g/bhp-hr for the standby generator.

Table B-9
Standby Generator NO_X Emission Limit Requirements

EPN	BACT	Proposed NO_X Emission Limit
EQT005	Turbocharger, Intercooler, Good Combustion Practice, and limiting operating hours to 500 hours annually	2.0 g/hp-hr

B.6.3 CO Candidate Controls – Standby Generator

From a search of the RBLC clearinghouse, the technologies available to potentially control CO emissions from stationary natural gas-fired IC engine(s) include the following:

- *Turbocharger*
- *Timing Retard*

The technical feasibility for these control candidates is discussed in Sections B.6.3.1 through B.6.3.2.

B.6.3.1 Turbocharger

Installation of a turbocharger can reduce CO emissions by allowing more efficient combustion. The proposed standby generator contains a turbocharger and thus this control technology is considered technically feasible.

B.6.3.2 Timing Retard

By adjusting the timing retard, the air-fuel mixture can be regulated to reduce CO emissions. This effectively derates the engine and reduces peak power available from the engine. Since this unit is designated as a standby unit, this would reduce the availability of peak power during emergency situations. As such, this control technology is considered technically infeasible.

B.6.4 Selection of CO BACT – Standby Generator

As indicated above, installation of a turbocharger is a technically feasible method for limiting CO emissions from an internal combustion engine. CCPL maintains that a turbocharger, combined with good combustion practices and limiting operating hours to 500 annually constitutes BACT for CO for the standby generator. CCPL anticipates that this will reduce CO emissions to 1.80 g/bhp-hr.

Table B-10
Standby Generator CO Emission Limit Requirements

EPN	BACT	Proposed CO Emission Limit
EQT005	Turbocharger, Good Combustion Practice, and limiting operating hours to 500 hours annually	1.8 g/hp-hr

B.6.5 $PM_{2.5}$ Candidate Controls – Standby Generator

Based on a technical review using the previously identified sources, the available control technologies for reduction of potential emissions of $PM_{2.5}$ from the combustion turbines are provided below:

- *Good combustion practice; and*
- *Natural gas fuel.*

B.6.6 $PM_{2.5}$ BACT Impact Analysis – Standby Generator

CCPL is currently proposing to use good combustion practice while burning only pipeline quality natural gas. Therefore, no additional ranking is necessary. In addition, there are no adverse economic, environmental or energy impacts associated with the available control candidates.

B.6.7 $PM_{2.5}$ BACT Determination – Standby Generator

Based upon the review for viable control options, the only available emissions control for emissions from IC engines is good combustion practice and burning only pipeline quality natural gas. Good combustion practices involve proper operation and maintenance of the standby engine (EPN EQT005). Creating and maintaining procedures as well as proper training are the best ways to ensure these criteria are being met. The Sinton Compressor Station will keep operating logs for malfunction as well as normal operations in accordance with good combustion practices. Maintenance logs will also be kept to ensure the generator sets are in good condition. In addition, CCPL will fire only pipeline quality natural gas. <u>Therefore, CCPL has determined that good combustion practice, use of only pipeline natural gas fuels and limiting operational hours to 500 annually constitute BACT for $PM_{2.5}$ emissions from EPN EQT005.</u>

Table B-11

Standby Generator $PM_{2.5}$ Emission Limit Requirements

EPN	BACT	Proposed $PM_{2.5}$ Emission Limit
EQT005	Good Combustion Practice, use of pipeline natural gas, and limiting operating hours to 500 hours annually	0.000071 lb/MMBtu

APPENDIX C – TURBINE AND ENGINE SPECS

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer	Engine Model TITAN 130-20502S CS/MD 59F MATCH
Job ID	
Inquiry Number	Fuel Type: SD NATURAL GAS — Water Injection: NO
Run By: Kevin M Frank — Date Run: 16-Jan-12	Engine Emissions Data: REV. 0.0

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
1 — 20048 HP 100.0% Load — Elev. 25 ft — Rel. Humidity 60.0% — Temperature 59.0 Deg. F			
PPMvd at 15% O2	25.00	50.00	25.00
ton/yr	62.13	75.66	21.67
lbm/MMBtu (Fuel LHV)	0.100	0.121	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.95	1.16	0.33
lbm/hr	14.19	17.27	4.95
2 — 20617 HP 100.0% Load — Elev. 25 ft — Rel. Humidity 60.0% — Temperature 45.0 Deg. F			
PPMvd at 15% O2	25.00	50.00	25.00
ton/yr	63.55	77.38	22.16
lbm/MMBtu (Fuel LHV)	0.100	0.122	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.94	1.15	0.33
lbm/hr	14.51	17.67	5.06
3 — 18784 HP 100.0% Load — Elev. 25 ft — Rel. Humidity 60.0% — Temperature 75.0 Deg. F			
PPMvd at 15% O2	25.00	50.00	25.00
ton/yr	59.02	71.86	20.58
lbm/MMBtu (Fuel LHV)	0.099	0.121	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.96	1.17	0.34
lbm/hr	13.47	16.41	4.70

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer	
Job ID	
Inquiry Number	
Run By: Kevin M Frank	Date Run: 16-Jan-12

Engine Model: TITAN 130-20502S CS/MD 59F MATCH	
Fuel Type: SD NATURAL GAS	Water Injection: NO
Engine Emissions Data: REV. 0.0	

4 | 16890 HP 100.0% Load | Elev. 25 ft | Rel. Humidity 60.0% | Temperature 95.0 Deg. F

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
PPMvd at 15% O2	25.00	50.00	25.00
ton/yr	54.88	66.82	19.14
lbm/MMBtu (Fuel LHV)	0.098	0.119	0.034
lbm/(MW-hr) (gas turbine shaft pwr)	0.99	1.21	0.35
lbm/hr	12.53	15.26	4.37

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
A Caterpillar Company

PREDICTED ENGINE PERFORMANCE

Customer	
Job ID	
Run By: **Kevin M Frank**	Date Run: **16-Jan-12**
Engine Performance Code: **REV. 3.54**	Engine Performance Data: **REV. 1.1**

Model	**TITAN 130-20502S**
Package Type	**CS/MD**
Match	**59F MATCH**
Fuel System	**GAS**
Fuel Type	**SD NATURAL GAS**

DATA FOR NOMINAL PERFORMANCE

Elevation	feet	25
Inlet Loss	in H2O	4.0
Exhaust Loss	in H2O	4.0

		1	2	3	4
Engine Inlet Temperature	deg F	59.0	45.0	75.0	95.0
Relative Humidity	%	60.0	60.0	60.0	60.0
Driven Equipment Speed	RPM	8351	8346	8264	8093
Specified Load	HP	FULL	FULL	FULL	FULL
Net Output Power	HP	20048	20617	18784	16890
Fuel Flow	mmBtu/hr	142.47	145.36	135.95	127.69
Heat Rate	Btu/HP-hr	7106	7051	7238	7560
Therm Eff	%	35.806	36.088	35.155	33.656
Engine Exhaust Flow	lbm/hr	392686	403587	374724	347959
PT Exit Temperature	deg F	944	923	959	985
Exhaust Temperature	deg F	944	923	959	985

Fuel Gas Composition (Volume Percent)

Methane (CH4)	92.79
Ethane (C2H6)	4.16
Propane (C3H8)	0.84
N-Butane (C4H10)	0.18
N-Pentane (C5H12)	0.04
Hexane (C6H14)	0.04
Carbon Dioxide (CO2)	0.44
Hydrogen Sulfide (H2S)	0.0001
Nitrogen (N2)	1.51

Fuel Gas Properties

LHV (Btu/Scf)	939.2	Specific Gravity	0.5970	Wobbe Index at 60F	1215.6

This performance was calculated with a basic inlet and exhaust system. Special equipment such as low noise silencers, special filters, heat recovery systems or cooling devices will affect engine performance. Performance shown is "Expected" performance at the pressure drops stated, not guaranteed.

Volatile Organic Compound, Sulfur Dioxide, and Formaldehyde Emission Estimates

Leslie Witherspoon
Solar Turbines Incorporated

PURPOSE

This Product Information Letter summarizes methods that are available to estimate emissions of volatile organic compounds (VOC), sulfur dioxide (SO_2), and formaldehyde from gas turbines. Most customers are required to estimate emissions of these pollutants during the air permitting process.

INTRODUCTION

In absence of site-specific or representative source test data, Solar refers customers to a United States Environmental Protection Agency (EPA) document titled "AP-42" or other appropriate EPA reference documents. AP-42 is a collection of emission factors for different emission sources. The emission factors found in AP-42 provide a generally accepted way of estimating emissions when more representative data are not available. The most recent version of AP-42 (dated April 2000) can be found at:

http://www.epa.gov/ttn/chief/ap42/ch03/index.html

Solar does not typically warranty the emission rates for VOC, SO_2 or formaldehyde.

Volatile Organic Compounds

Most permitting agencies require gas turbine users to estimate emissions of VOC, a subpart of the unburned hydrocarbon (UHC) emissions, during the air permitting process. Volatile organic compounds, non-methane hydrocarbons (NMHC), and reactive organic gases (ROG) are some of the many ways of referring to the non-methane (and non-ethane) portion of an "unburned hydrocarbon" emission estimate.

For natural gas fuel, most of Solar's customers use 10-20% of the UHC emission rate to represent VOC emissions. The estimate of 10-20% is based on a ratio of total non-methane hydrocarbons to total organic compounds. The use of 10 up to 20% provides a conservative estimate of VOC emissions. The balance of the UHC is assumed to be primarily methane.

For liquid fuel, it is appropriate to estimate that 100% of the UHC emission estimate is VOC.

Sulfur Dioxide

Sulfur dioxide emissions are produced by conversion of sulfur in the fuel to SO_2. Since Solar does not control the amount of sulfur in the fuel, we are unable to generically predict SO_2 emissions. Customers generally estimate SO_2 emissions with a mass balance calculation by assuming that any sulfur in the fuel will convert to SO_2. For reference, the typical mass balance equation is shown below.

Variables: wt % of sulfur in fuel
Btu/lb fuel (LHV*)
MMBtu/hr fuel flow (LHV)

$$\frac{\text{lb } SO_2}{\text{hr}} = \left(\frac{\text{wt\% Sulfur}}{100}\right)\left(\frac{\text{lb fuel}}{\text{Btu}}\right)\left(\frac{10^6 \text{ Btu}}{\text{MMBtu}}\right)\left(\frac{\text{MMBtu fuel}}{\text{hr}}\right)\left(\frac{\text{MW } SO_2}{\text{MW Sulfur}}\right)$$

As an alternative to a mass balance calculation, EPA's AP-42 document can be used. AP-42 (Table 3.1-2a, April 2000) suggests emission factors of 0.0034 lb/MMBtu for gas fuel (HHV*) and 0.033 lb/MMBtu for liquid fuel (HHV).

*LHV = Lower Heating Value; HHV = Higher Heating Value

Formaldehyde

In gas turbines, formaldehyde emissions are a result of incomplete combustion. Formaldehyde in the exhaust stream is unstable and very difficult to measure. In addition to turbine characteristics including combustor design, size, maintenance history, and load profile, the formaldehyde emission level is also affected by:

- Ambient temperature
- Humidity
- Atmospheric pressure
- Fuel quality
- Formaldehyde concentration in the ambient air
- Test method measurement variability
- Operational factors

The emission factor data in Table 1 is an excerpt from an EPA memo: "Revised HAP Emission Factors for Stationary Combustion Turbines, 8/22/03." The memo presents hazardous air pollutant (HAP) emission factor data in several categories including: mean, median, maximum, and minimum. The emission factors in the memo are a compilation of the HAP data EPA collected during the Maximum Achievable Control Technology (MACT) standard development process. The emission factor documentation shows there is a high degree of variability in formaldehyde emissions from gas turbines, depending on the manufacturer, rating size of equipment, combustor design, and testing events. To estimate formaldehyde emissions from gas turbines, users should use the emission factor(s) that best represent the gas turbines actual / planned operating profile. Refer to the memo for alternative emission factors.

Table 1. EPA's Total HAP and Formaldehyde Emission Factors for <50 MW Lean-Premix Gas Turbines burning Natural Gas

(Source: Revised HAP Emission Factors for Stationary Combustion Turbines, OAR-2002-0060, IV-B-09, 8/22/03)

Pollutant	Engine Load	95% Upper Confidence of Mean, lb/MMBtu HHV	95% Upper Confidence of Data, lb/MMBtu HHV	Memo Reference
Total HAP	> 90%	0.00144	0.00258	Table 19
Total HAP	All	0.00160	0.00305	Table 16
Formaldehyde	> 90%	0.00127	0.00241	Table 19
Formaldehyde	All	0.00143	0.00288	Table 16

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Emission Estimates at Start-up, Shutdown, and Commissioning for SoLoNOx Combustion Products

Leslie Witherspoon
Solar Turbines Incorporated

PURPOSE

The purpose of this Product Information Letter (PIL) is to provide emission estimates for start-up and shutdown events for *Solar*® gas turbines with *SoLoNOx*™ dry low emissions combustion systems. The commissioning process is also discussed.

INTRODUCTION

The information presented in this document is representative for both generator set (GS) and compressor set/mechanical drive (CS/MD) combustion turbine applications. Operation of duct burners and/or any add-on control equipment is not accounted for in the emissions estimates. Emissions related to the start-up, shutdown, and commissioning of combustion turbines will not be guaranteed or warranted.

Combustion turbine start-up occurs in one of three modes: cold, warm, or hot. On large, utility size, combustion turbines, the start-up time varies by the "mode". The start-up duration for a hot, warm, or cold *Solar* turbine is less than 10 minutes in simple-cycle and most combined heat and power applications.

Heat recovery steam generator (HRSG) steam pressure is usually 250 psig or less. At 250 psig or less, thermal stress within the HRSG is minimized and, therefore, firing ramp-up is not limited. However, some combined heat and power plant applications will desire or dictate longer start-up times, therefore emissions assuming a 60-minute start are also estimated.

A typical shutdown for a *Solar* turbine is <10 minutes. Emissions estimates for an elongated shutdown, 30-minutes, are also included.

Start-up and shutdown emissions estimates for the *Mercury*™ 50 engine are found in PIL 205.

For start-up and shutdown emissions estimates for conventional combustion turbines, landfill gas, digester gas, or other alternative fuel applications, contact Solar's Environmental Programs Department.

START-UP SEQUENCE

The start-up sequence, or getting to *SoLoNOx* combustion mode, takes three steps:

1. Purge-crank
2. Ignition and acceleration to idle
3. Loading / thermal stabilization

During the "purge-crank" step, rotation of the turbine shaft is accomplished with a starter motor to remove any residual fuel gas in the engine flow path and exhaust. During "ignition and acceleration to idle," fuel is introduced into the combustor and ignited in a diffusion flame mode and the engine rotor is accelerated to idle speed.

The third step consists of applying up to 50% load[1] while allowing the combustion flame to transition and stabilize. Once 50% load is achieved, the turbine transitions to *SoLoNOx* combustion mode and the engine control system begins to hold the combustion primary zone temperature and limit pilot fuel to achieve the targeted nitrogen oxides (NOx), carbon monoxide (CO), and unburned hydrocarbons (UHC) emission levels.

Steps 2 and 3 are short-term transient conditions making up less than 10 minutes.

SHUTDOWN PROCESS

Normal, planned cool down/shutdown duration varies by engine model. The *Centaur*® 40, *Centaur* 50, *Taurus*™ 60, and *Taurus* 65 engines take about 5 minutes. The *Taurus* 70, *Mars*® 90 and 100, *Titan*™ 130 and *Titan* 250 engines take about 10 minutes. Typically, once the shutdown process starts, the emissions will remain in *SoLoNOx* mode for ~ 90 seconds and move into a transitional mode for the balance of the estimated shutdown time (assuming the unit was operating at full-load).

START-UP AND SHUTDOWN EMISSIONS ESTIMATES

Tables 1 through 5 summarize the estimated pounds of emissions per start-up and shutdown event for each product. Emissions estimates are presented for both GS and CS/MD applications on both natural gas and liquid fuel (diesel #2). The emissions estimates are calculated using empirical exhaust characteristics.

COMMISSIONING EMISSIONS

Commissioning generally takes place over a two-week period. Static testing, where no combustion occurs, usually requires one week and no emissions are expected. Dynamic testing, where combustion will occur, will see the engine start and shutdown a number of times and a variety of loads will be placed on the system. It is impossible to predict how long the turbine will run and in what combustion / emissions mode it will be running. The dynamic testing period is generally followed by one to two days of "tune-up" during which the turbine is running at various loads, most likely within low emissions mode (warranted emissions range).

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[1] 40% load for the *Titan* 250 engine on natural gas. 65% load for all engines on liquid fuel (except 80% load for the *Centaur* 40).

Table 1. Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx Generator Set Applications
10 Minute Start-up and 10 Minute Shutdown
Natural Gas Fuel

Data will NOT be warranted under any circumstances

	Centaur 40 4701S				Centaur 50 6201S				Taurus 60 7901S				Taurus 65 8401S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	0.6	58.1	3.3	359	0.8	75.0	4.3	454	0.8	78.5	4.5	482	0.9	85.8	4.9	523
Total Emissions per Shutdown (lbs)	0.3	25.5	1.5	160	0.4	31.1	1.8	194	0.4	34.7	2.0	217	0.4	38.2	2.2	237

	Taurus 70 10801S				Mars 90 13002S GSC				Mars 100 16002S GSC				Titan 130 20501S				Titan 250 30002S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	1.1	103.9	5.9	634	1.4	129.0	7.4	868	1.6	151.2	8.6	952	2.1	195.6	11.2	1,194	3.0	273.1	15.6	1,925
Total Emissions per Shutdown (lbs)	1.3	110.7	6.3	689	1.7	147.9	8.4	912	1.9	166.8	9.5	1,026	2.4	210.0	12.0	1,303	3.8	325.6	18.6	1,993

Assumes ISO conditions: 59F, 60% RH, sea level, no losses

Assumes unit is operating at full load prior to shutdown.

Assumes natural gas fuel; ES 9-98 compliant.

Table 2. Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx Generator Set Applications
60 Minute Start-up and 30 Minute Shutdown
Natural Gas Fuel

Data will NOT be warranted under any circumstances

	Centaur 40 4701S				Centaur 50 6201S				Taurus 60 7901S				Taurus 65 8401S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	4.1	219.4	13.0	3,420	5.0	272.4	16.1	4,219	5.7	299.8	17.8	4,780	6.1	326.5	19.3	5,074
Total Emissions per Shutdown (lbs)	1.8	121.1	7.1	1,442	2.3	163.3	9.5	1,834	2.5	163.5	9.6	1,994	2.6	177.2	10.4	2,119

	Taurus 70 10801S				Mars 90 13002S				Mars 100 16002S				Titan 130 20501S				Titan 250 30002S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	7.6	410.3	24.2	6,164	10.5	570.8	33.7	8,641	11.3	583.5	34.6	9,691	13.8	740.4	43.8	11,495	15.3	548.1	34.1	16,253
Total Emissions per Shutdown (lbs)	3.3	223.0	13.0	2,588	4.3	277.0	16.2	3,685	4.8	308.1	18.0	4,056	6.0	405.3	23.7	4,826	6.4	324.3	19.5	7,222

Assumes ISO conditions: 59F, 60% RH, sea level, no losses.

Assumes unit is operating at full load prior to shutdown.

Assumes natural gas fuel; ES 9-98 compliant.

Table 3. Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx CS/MD Applications
10 Minute Start-up and 10 Minute Shutdown
Natural Gas Fuel

Data will NOT be warranted under any circumstances

	Centaur 40 4702S				Centaur 50 6102S				Taurus 60 7802S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	0.7	64.4	3.7	392	0.8	69.1	4.0	469	0.7	64.3	3.7	410
Total Emissions per Shutdown (lbs)	0.3	30.2	1.7	181	0.4	35.4	2.0	217	0.4	33.0	1.9	204

	Taurus 70 10302S				Mars 90 13002S CSMD				Mars 100 16002S CSMD				Titan 130 20502S				Titan 250 30002S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	0.8	73.1	4.2	519	1.2	109.3	6.2	805	1.4	123.5	7.1	829	1.9	176.9	10.1	1,161	3.1	284.8	16.3	1,794
Total Emissions per Shutdown (lbs)	1.1	93.4	5.3	575	1.5	132.6	7.6	817	1.7	149.2	8.5	920	2.4	207.6	11.9	1,272	3.6	313.4	17.9	1,918

Assumes ISO conditions: 59F, 60% RH, sea level, no losses.

Assumes unit is operating at full load prior to shutdown.

Assumes natural gas fuel; ES 9-98 compliant.

Table 4. Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx Generator Set
10 Minute Start-up and 10 Minute Shutdown
Liquid Fuel (Diesel #2)

Data will NOT be warranted under any circumstances

	Centaur 40 4701S				Centaur 50 6201S				Taurus 60 7901S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	1.3	44.5	7.4	473	1.7	59.0	9.8	601	1.7	59.8	9.9	636
Total Emissions per Shutdown (lbs)	0.6	17.3	2.8	211	0.7	21.2	3.4	256	0.8	23.5	3.8	286

	Taurus 70 10801S				Mars 100 16002S GSC				Titan 130 20501S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	2.3	78.5	13.0	823	3.4	114.1	18.8	1,239	4.3	147.5	24.4	1,547
Total Emissions per Shutdown (lbs)	2.5	73.6	12.0	889	3.8	111.4	18.1	1,331	4.7	139.1	22.6	1,677

Assumes ISO conditions: 59F, 60% RH, sea level, no losses.

Assumes unit is operating at full load prior to shutdown.

Assumes #2 Diesel fuel; ES 9-98 compliant.

Table 5. Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx Generator Set
60 Minute Start-up and 30 Minute Shutdown
Liquid Fuel (Diesel #2)

Data will NOT be warranted under any circumstances

	Centaur 40 4701S				Centaur 50 6201S				Taurus 60 7901S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	11.7	194.7	30.9	4,255	15.2	271.9	43.3	5,302	14.7	282.6	45.0	5,962
Total Emissions per Shutdown (lbs)	4.4	84.7	13.6	1,816	6.7	164.3	27.0	2,334	6.3	159.0	26.0	2,515

	Taurus 70 10801S				Mars 100 16002S				Titan 130 20501S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	18.4	360.3	57.4	7,375	29.1	552.0	87.7	11,685	34.4	677.0	108.0	13,731
Total Emissions per Shutdown (lbs)	8.0	207.8	34.1	3,156	12.3	302.6	49.4	4,970	15.0	388.5	63.7	5,876

Assumes ISO conditions: 59F, 60% RH, sea level, no losses.
Assumes unit is operating at full load prior to shutdown.
Assumes #2 Diesel fuel; ES 9-98 compliant.

Particulate Matter Emission Estimates

Leslie Witherspoon
Solar Turbines Incorporated

PURPOSE

Since particulate matter is a regulated pollutant, most air permitting agencies require customers to provide particulate matter emission estimates during the air permitting process. In addition, many air permit agencies require dispersion modeling analyses for particulate matter. More and more often, regulatory agencies are including a particulate matter compliance testing requirement in the air permit.

This document summarizes Solar's recommended $PM_{10/2.5}$ emission levels for our combustion turbines. The recommended levels are based on an analysis of emissions tests collected from customer sites.

Particulate Matter Definition

National Ambient Air Quality Standards (NAAQS) for particulate matter were first set in 1971. Total suspended particulate (TSP) was the first indicator used to represent suspended particles in the ambient air. Since July 1, 1987, the Environmental Protection Agency (EPA) has used the indicator PM_{10}, which includes only the particles with aerodynamic diameter smaller than 10 micrometers. PM_{10} (coarse particles) come from sources such as windblown dust from the desert or agricultural fields and dust kicked up on unpaved roads by vehicle traffic.

The EPA added a $PM_{2.5}$ ambient air standard in 1997. $PM_{2.5}$ includes particles with an aerodynamic diameter less than 2.5 micrometers. $PM_{2.5}$ (fine particles) are generally emitted from activities such as industrial and residential combustion and from vehicle exhaust. Fine particles are also formed in the atmosphere when gases such as sulfur dioxide, nitrogen oxides, and volatile organic compounds, emitted by combustion activities, are transformed by chemical reactions.

Nearly all particulate matter from gas turbine exhaust is less than one micrometer (micron) in diameter. Thus the emission rates of TSP, PM_{10}, and $PM_{2.5}$ from gas turbines are theoretically equivalent although source testing will show significant variation due to test method detection levels and processes.

TESTING FOR PARTICULATE MATTER

The turbine combustion process has little effect on the particulate matter generated and measured. The largest contributor to particulate matter emissions for gas and liquid fired combustion turbines is measurement technique and error. Other, minor contributing, sources of particulate matter emissions include carbon, ash, fuel-bound sulfur, artifact sulfate formation, compressor/lubricating oils, and inlet air.

Historical customer particulate matter source test data show that there is significant variability from test to test. The source test results support the common industry argument that particulate matter from natural gas fired combustion sources is difficult to measure accurately. The reference test methods for particulate matter were developed primarily for measuring emissions from coal-fired power plants and other major emitters of particulates. Particulate concentrations from gas turbine can be 100 to 10,000 times lower than the "traditional" particulate sources. The test methods were not developed or verified for low emission levels. There are interferences, insignificant at higher exhaust particulate matter concentrations that result in emissions greater than the actual emissions from gas turbines. New methods are being developed to address this problem.

Due to measurement and procedural errors, the measured results, in most cases, may not be representative of actual particulate matter emitted. There are many potential error sources in measuring particulate matter. Most of these have to do with contamination of the samples, material from the sampling apparatus getting into the samples, and general sloppiness in samples and analysis.

Recommended Particulate Matter Emission Factors

When necessary to support the air permitting process Solar recommends using a $PM_{10/2.5}$ emission factor of 0.021 lb/MMBtu fuel input (HHV) for natural gas. For landfill gas, the recommended emission factor is 0.03 lb/MMBtu fuel input (HHV). For liquid fuel, the recommended emission factor is 0.06 lb/MMBtu fuel input (HHV). The liquid fuel emission factor assumes fuel sulfur content is <500 ppm and ash content is <0.005% by wt.

The emission levels cited above are only for engine operation with the fuels listed. Other fuels many not yield similar results.

At this time, Solar does not recommend using AP-42 (EPA AP-42 "Compilation of Air Pollutant Emission Factors.") AP-42. While some source tests have had similar results to AP-42, others are higher.

Test Method Recommendation

For customers who conduct emission source tests for particulate matter, Solar recommends that EPA Methods 201/201A[1] be used to measure the “front half”. “Front half” represents filterable particulate matter.

EPA Method 202[2] (with nitrogen purge and field blanks) should be used to measure the “back half”. “Back half” measurements represent the condensable portion of particulate matter.

EPA Method 5[3], which measures the front and back halves may be substituted (e.g. where exhaust temperatures do not allow the use of Method 202).

Testing should include three test runs of 4 hours each.

Solar recommends using the aforementioned test methods until more representative test methods are developed and made commercially available.

References

[1] EPA Method 201, Determination of PM10 Emissions, Exhaust Gas Recycle Procedure. EPA Method 201A, Determination of PM10 Emissions, Constant Sampling Rate Procedure, 40 CFR 60, Part 60, Appendix A.

[2] EPA Method 202, Determination of Condensible Particulate Emissions from Stationary Sources, 40 CFR 60, Part 60, Appendix A.

[3] EPA Method 5, Determination of Particulate Emissions from Stationary Sources, 40 CFR 60, Part 60, Appendix

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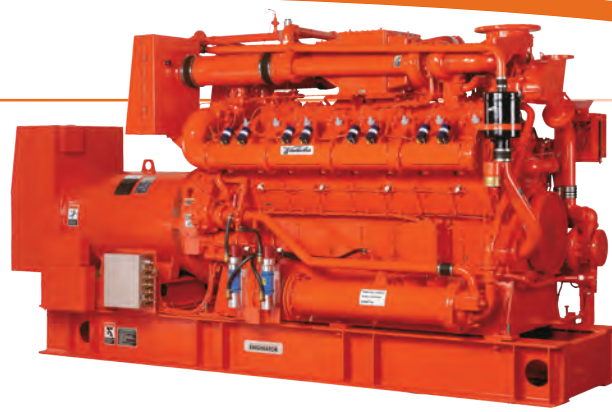
DRESSER Waukesha

VGF48GL/GLD

VGF® Series Gas Enginator® Generating System
610 - 860 kWe

Specifications



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Dresser Waukesha Engine: P48GL/GLD
Cylinders: V16
Piston Displacement: 2924 cu. in. (48 L)
Bore & Stroke: 5.98" x 6.5" (152 x 165 mm)
Compression Ratio: 11:1
Jacket Water System Capacity: 58 gal. (219 L)
Starting System: 24V DC electric
Lube Oil Capacity: 113 gal. (428 L)

Standard Equipment

AIR CLEANER – Two stage, dry panel type with rain shield and service indicator. Engine mounted.

BARRING DEVICE – Manual.

BASE – Engine, generator and radiator or heat exchanger are mounted and aligned on a welded steel wide flange base, suitable for solid, or spring isolator mounting on a proper foundation. Base is equipped with lifting eyes and provision for jacking.

BREATHER – Closed system.

CONNECTING RODS – Drop forged alloy steel, angle split, serrated joint, oil jet piston pin lubrication.

COOLING SYSTEM – Choice of mounted radiator with pusher fan, core guard and duct adaptor, heat exchanger with shipped loose expansion tank or flanged connections for remote radiator cooling.

CRANKCASE – Alloy cast iron, fully ribbed, integral with cylinder frame.

CRANKSHAFT – Drop forged alloy steel with thru hardened journals, dynamically balanced and fully counterweighted. Viscous vibration dampener.

CYLINDER HEADS – Individual, interchangeable valve–in–head type with deep section alloy casting. Two hard–faced intake and two hard–faced exhaust valves per cylinder. Replaceable intake and exhaust valve seats. Mechanical valve lifters with pivoted roller followers.

CYLINDERS – Removable wet type liners of centrifugally cast alloy iron.

ENGINE PROTECTION SHUTDOWN CONTACTS – High water temperature, low oil pressure, and overspeed.

EXHAUST – Water–cooled, cast iron exhaust manifolds. Single vertical flexible stainless steel exhaust connection with ANSI 10" 125# outlet flange.

FUEL SYSTEM (GL) – Two natural gas carburetors, one Fisher Y692 gas regulator, one 2" NPT flexible connection (shipped loose) and one 2" NPT Magnatrol gas solenoid valve (shipped loose). Fuel pressure - 25 PSIG minimum and 50 PSIG maximum.

FUEL SYSTEM (GLD) – Two natural gas carburetors, one DUNGS 5080 gas regulator (shipped loose), one 3" NPT flexible connection (shipped loose), and one 2" NPT Magnatrol gas solenoid valve (shipped loose). Fuel pressure – 5 PSIG minimum and 8 PSIG maximum.

GENERATOR – Open, drip–proof, direct connected, synchronous, fan cooled, AC revolving field type, 2/3 pitch, single bearing generator with PMG brushless exciter for 300% short circuit sustain for 10 seconds (250% for 50 Hz) and motor starting. TIF and Deviation Factor within NEMA MG–1.32. Voltage: 480/277, 3 phase, 6 or 12 wire Wye, 60 Hz, and 400/230, 3 phase, 6 or 12 wire Wye, 50 Hz. Temperature rise within NEMA 105° C for continuous duty, within NEMA 130° C for standby duty. Voltage regulation is ±0.5%. All generators are rated at 0.8 power factor, are mounted on the engine flywheel housing, and have multiple steel disc flexible coupling drive.

GOVERNOR – Woodward model EG3P electric actuator (mounted) and magnetic pick-up (mounted). Requires a separate electric governor control, Woodward Model 2301D (not included). See Code 6020D.

IGNITION – Waukesha Custom Engine Control electronic ignition system with coils, cables, hall effect pickup and spark plugs. Non–shielded. 24V DC power required. Includes emergency stop/service engine protection switch for local override of remote controls.

INTERCOOLER – Air to water.

INSTRUMENT PANEL – Engine mounted, includes water temperature, oil temperature, oil pressure, intake manifold temperature and intake manifold pressure gauges.

JUNCTION BOXES – Separate AC & DC junction boxes for engine wiring and external connections.

LUBRICATION SYSTEM – Gear type pump, replaceable spin on oil filters and industrial base type oil pan. Engine mounted shell and tube oil cooler, thermostatic valve for oil temperature control, and prelube pump. Engine mounted 230 VAC, single phase 50/60 Hz, or 208 VAC, single phase 60Hz, electric driven prelube pump with motor starter. Continuous prelube not available.

PAINT – Oilfield Orange.

PISTONS – Aluminum alloy, three ring, with patented high turbulence combustion bowl. Oil jet cooled with full floating piston pin. 11:1 compression ratio.

STARTING SYSTEM – 24V DC starting motor. Crank termination switch, (shipped loose).

TURBOCHARGERS – Dry–type with wastegate.

VOLTAGE REGULATOR – Automatic type (shipped loose).

WATER CIRCULATING SYSTEM, AUXILIARY CIRCUIT – Gear driven pump for intercooler and oil cooler. Inlet temperature of 130° F (54° C) for all models.

WATER CIRCULATING SYSTEM, JACKET WATER CIRCUIT – 180° – 190° F (82° – 88° C) thermostatic temperature regulation. Gear–driven pump.

WAUKESHA CUSTOM ENGINE CONTROL DETONATION SENSING MODULE (DSM) – Includes individual cylinder sensors, Detonation Sensing Module, and filter. Device is compatible with Waukesha CEC Ignition Module only. Detonation Sensing Module and DSM Filter are mounted and wired. 24V DC power is required. The DSM meets Canadian Standards Association Class I, Division 2, Group D, hazardous location requirements.

PERFORMANCE DATA: VGF48GL/GLD Gas Enginator® Generating System

Heat Exchanger/Water Connection Cooling Intercooler Water: 130°F (54°C)		Continuous Power		Standby Power	
		1800 rpm 60 Hz	1500 rpm 50 Hz	1800 rpm 60 Hz	1500 rpm 50 Hz
	kW Rating	830**	685**	860	720
	BSFC btu/bhp-hr (kJ/kW-hr)	6869 (9713)	6688 (9458)	6825 (9655)	6643 (9397)
	Fuel Consumption Btu/hr x 1000 (kW)	8071 (2365)	6521 (1911)	8395 (2461)	6809 (1996)
Heat Balance	Heat to Jacket Water Btu/hr x 1000 (kW)	2112 (619)	1797 (527)	2155 (631)	1850 (542)
Heat Balance	Heat to Lube Oil Btu/hr x 1000 (kW)	258 (76)	190 (56)	262 (77)	191 (56)
Heat Balance	Heat to Intercooler Btu/hr x 1000 (kW)	527 (154)	359 (105)	566 (166)	397 (115)
Heat Balance	Heat to Radiation Btu/hr x 1000 (kW)	146 (43)	136 (40)	144 (42)	134 (39)
Heat Balance	Total Exhaust Heat Btu/hr x 1000 (kW)	2340 (686)	1800 (528)	2380 (697)	1850 (542)
Intake/ Exhaust System	Induction Air Flow scfm (Nm^3/hr)	2478 (3809)	2002 (3077)	2425 (3724)	1975 (3039)
Intake/ Exhaust System	Exhaust Flow lb/hr (kg/hr)	10805 (4901)	8728 (3959)	11070 (5020)	9030 (4096)
Intake/ Exhaust System	Exhaust Temperature °F (°C)	839 (448)	802 (428)	841 (449)	798 (425)
Radiator Cooling - Mounted Intercooler Water: 130°F (54°C)					
	kW Rating	810**	670**	825	700
	BSFC btu/bhp-hr (kJ/kW-hr)	6869 (9713)	6688 (9458)	6825 (9655)	6643 (9397)
	Fuel Consumption Btu/hr x 1000 (kW)	8071 (2365)	6521 (1911)	8395 (2461)	6809 (1996)
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Intake/ Exhaust System	Exhaust Temperature °F (°C)	839 (448)	802 (428)	841 (449)	798 (425)
Intake/ Exhaust System	Radiator Air Flow scfm (m^3/min)	63750 (1805)	73468 (2080)	63750 (1805)	73468 (2080)
Emissions	NOx g/bhp-hr (mg/nm^3 @ 5% O_2)	2.00 (824)	2.50 (1004)	2.00 (824)	2.50 (1004)
Emissions	CO g/bhp-hr (mg/nm^3 @ 5% O_2)	1.30 (540)	1.30 (518)	1.30 (540)	1.30 (518)
Emissions	THC g/bhp-hr (mg/nm^3 @ 5% O_2)	1.60 (649)	2.00 (806)	1.60 (649)	2.00 (806)
Emissions	NMHC g/bhp-hr (mg/nm^3 @ 5% O_2)	0.26 (105)	0.30 (121)	0.26 (105)	0.30 (121)

Typical heat data is shown, however no guarantee is expressed or implied. Consult your Dresser Waukesha Application Engineering Department for system application assistance.

All natural gas engine ratings are based on a fuel of 900 Btu/ft^3 (35.3 MJ/nm^3) SLHV, with a 91 WKI®. For conditions or fuels other than standard, consult the Dresser Waukesha Application Engineering Department.

Data based on standard conditions of 77°F (25°C) ambient temperature, 29.53 inches Hg (100kPa) barometric pressure, 30% relative humidity (0.3 inches HG / 1 kPa water vapor pressure).

Fuel consumption based on ISO3046/1-1995 with a tolerance of +5% for commercial quality natural gas having a 900 BTU/ft^3 (35.3 MJ/nm^3) SLHV.

Heat data based on fuel consumption +2%.

Heat rejection based on cooling exhaust temperature to 77°F (25°C).

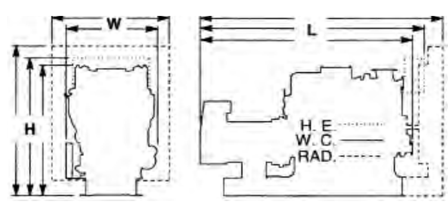
Rating Standard: The Waukesha Enginator ratings are based on ISO 3046/1-1995 with an engine mechanical efficiency of 90% and auxiliary water temperature Tcra as specified limited to ±10°F (±5°C). Ratings also valid for ISO 8528 and DIN 6271, BS 5514 standard atmospheric conditions.

Continuous Power Rating: The highest electrical power output of the Enginator available for an unlimited number of hours per year, less maintenance. It is permissable to operate the Enginator with up to 10% overload for two hours in each 24 hour period.

Standby Power Rating: This rating applies to those systems used as a secondary source of electrical power. This rating is the electrical power output of the Enginator (no overload) 24 hours a day, for the duration of a power source outage.

**Requires option code 1100.

Consult your local Waukesha representative for system application assistance. The manufacturer reserves the right to change or modify without notice, the design or equipment specifications as herein set forth without incurring any obligation either with respect to equipment previously sold or in the process of construction except where otherwise specifically guaranteed by the manufacturer.



Cooling Equipment	L in (mm)	W in (mm)	H in (mm)	Avg. Wt. lb (kg)
Heat Exchanger	208 (5280)	68 (1720)	96 (2440)	24980 (11340)
Water Cooler	176 (4470)	68 (1720)	96 (2440)	23000 (10440)
Radiator	228 (5790)	105 (2670)	136 (3230)	30200 (13700)

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APPENDIX D – RACT/BACT/LAER CLEARINGHOUSE RETRIEVALS

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
*SD-0005	DEER CREEK STATION	28.0505-PSD	Combustion turbine/heat recovery steam generator	Selective catalytic reduction	25.8	POUNDS PER HOUR
AK-0062	BADAMI DEVELOPMENT FACILITY	AQ0417CPT05, REVISION 1	SOLAR MARS 90 TURBINE	DRY LOW NOX COMBUSTION TECHNOLOGY (SOLONOX)	28.4	LB/H
AK-0066	ENDICOTT PRODUCTION FACILITY, LIBERTY DEVELOPMENT PROJECT	AQ0181CPT06, REVISION 2	EU ID 10A, TURBINE	DRY LOW NOX COMBUSTORS (DLN)	25	PPMV AT 15% O2
AK-0071	INTERNATIONAL STATION POWER PLANT	AQ0164CPT01	GE LM6000PF-25 Turbines (4)	Selective Catalytic Reduction and Dry Low NOx Combustion	5	PPMDV
AL-0208	EXXON MOBILE BAY -- NORTHWEST GULF FIELD	503-0013-X00	TURBINE, SIMPLE CYCLE	SOLONOX COMBUSTOR	25	PPM @ 15%O2
AL-0209	EXXON MOBILE -- MOBILE BAY - BON SECURE BAY FIELD	503-0012-X005	TURBINE, SIMPLE CYCLE	SOLONOX COMBUSTION	25	PPM @ 15% O2
AL-0251	HILLABEE ENERGY CENTER	310-0022-X001	COMBUSTION TURBINE	LOW-NOX BURNER SCR	24.6	LB/H
AR-0105	AECI - DELL	1903-AOP-R7	COMBUSTION TURBINE #1 (SN-01) NO. 2 FUEL OIL SERVICE	SELECTIVE CATALYTIC REDUCTION	52.3	LB/H
AR-0105	AECI - DELL	1903-AOP-R7	COMBUSTION TURBINE #2 (SN-02) NO. 2 FUEL OIL	SELECTIVE CATALYTIC REDUCTION	52.3	LB/H
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	S01-004	TURBINE, COMBINED CYCLE & DUCT BURNER	SCR	2	PPM @ 15% O2
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	S01-004	TURBINE, COMBINED CYCLE	SCR	2	PPM @ 15% O2
AZ-0047	WELLTON MOHAWK GENERATING STATION	1001653	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - SW501F TURBINES OPTION	LOW NOX BURNERS AND SELECTIVE CATALYTIC REDUCTION	2	PPM @ 15% O2
AZ-0047	WELLTON MOHAWK GENERATING STATION	1001653	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - GE7FA TURBINES OPTION	LOW NOX BURNERS AND SELECTIVE CATALYTIC REDUCTION	2	PPM AT 15% O2
CA-1051	THREE MOUNTAIN POWER, LLC	99-PO-01	GAS TURBINE: COMBINED CYCLE >= 50 MW	SCR SYSTEM, AND OXIDATION CATALYST	2.5	PPMVD @ 15% O2
CA-1052	WESTERN MIDWAY SUNSET POWER PROJECT	S-1135-313-0	GAS TURBINE: COMBINED CYCLE >= 50 MW	SCR SYSTEM, AND OXIDATION CATALYST	2	PPMVD @ 15% O2
CA-1142	PASTORIA ENERGY FACILITY	SJ 99-03	3 COMBUSTION TURBINES	XONON CATALYTIC COMBUSTORS OR DRY LOW NOX BURNERS WITH SCR	2.5	PPMVD
CA-1143	SUTTER POWER PLANT	SAC 98-01	2 COMBUSTION TURBINES	DRY LOW NOX BURNERS & SCR	2.5	PPMVD
CA-1144	BLYTHE ENERGY PROJECT II	SE 02-01	2 COMBUSTION TURBINES	SELECTIVE CATALYTIC REDUCTION	2	PPMVD
CA-1174	EL CAJON ENERGY LLC	987824	Gas turbine simple cycle	Water injection and SCR	2.5	PPMV

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
CA-1175	ESCONDIDO ENERGY CENTER LLC	985693	Gas turbine simple cycle	SCR water injection	2.5	PPMV@15% OXYGEN
CA-1176	ORANGE GROVE PROJECT	985708	Gas turbine simple cycle	SCR water injection	2.5	PPM
CA-1177	OTAY MESA ENERGY CENTER LLC	978379	Gas turbine combined cycle	SCR	2	PPMVD@15% OXYGEN
CA-1178	APPLIED ENERGY LLC	987494	Gas turbine combined cycle	SCR	2	PPM
CO-0056	ROCKY MOUNTAIN ENERGY CENTER, LLC	05WE0524	NATURAL-GAS FIRED, COMBINED-CYCLE TURBINE	LOW NOX BURNERS AND SCR	3	PPM @ 15% O2
CO-0058	CHEYENNE STATION	03WE0910303-	FREP TURBINE	TURBINE EQUIPPED WITH SOLONOX II COMBUSTION TECHNOLOGY (DRY LOW NOX)	15	PPMVD
CO-0058	CHEYENNE STATION	03WE0910303-	CPP TURBINES	GOOD COMBUSTION PRACTICES (SEE NOTES)	48.8	PPM @ 15% O2
CO-0059	CHEYENNE STATION	04WE1390	PHASE II TURBINE	SOLONOX II (DRY LOW NOX).	15	PPM @ 15% O2
CO-0064	RAWHIDE ENERGY STATION	07LR0017	UNIT F COMBUSTION TURBINE	DRY LOW NOX COMBUSTION SYSTEM	9	PPMVD
CT-0151	KLEEN ENERGY SYSTEMS, LLC	104-0131 AND 104-0133	SIEMENS SGT6-5000F COMBUSTION TURBINE #1 AND #2 (NATURAL GAS FIRED) WITH 445 MMBTU/HR NATURAL GAS DUCT BURNER	LOW NOX BURNER AND SELECTIVE CATALYTIC REDUCTION	15.5	LB/H
CT-0151	KLEEN ENERGY SYSTEMS, LLC	104-0131 AND 104-0133	SIEMENS SGT6-5000F COMBUSTION TURBINE #1 AND #2 (OIL FIRED) WITH 445 MMBTU/HR NATURAL GAS DUCT BURNER	WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION	48.4	LB/H
FL-0261	ARVAH B. HOPKINS GENERATING STATION	PSD-FL-343	TURBINE, SIMPLE CYCLE, NATURAL GAS, (2)	WATER INJECTION SYSTEM, SCR	5	PPMVD @15% O2
FL-0261	ARVAH B. HOPKINS GENERATING STATION	PSD-FL-343	TURBINE, SIMPLE CYCLE (2) FUEL OIL	WATER INJECTION SYSTEM, SCR	5	PPMVD @15% O2
FL-0263	FPL TURKEY POINT POWER PLANT	PSD-FL-338	170 MW COMBUSTION TURBINE, 4 UNITS	NOX EMISSIONS WILL BE REDUCED WITH DRY LOW-NOX (DLN) COMBUSTION TECHNOLOGY FOR GAS FIRING AND WATER INJECTION FOR OIL FIRING. IN COMBINATION WITH THESE NOX CONTROLS, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM FURTHER REDUC	2	PPMVD@ 15 % O2
FL-0265	HINES POWER BLOCK 4	PSD-FL-342 AND 1050234-010-AC	COMBINED CYCLE TURBINE	SCR	2.5	PPM
FL-0266	PAYNE CREEK GENERATING STATION/SEMINOLE ELECTRIC	PSD-FL-344 AND 0490340-003-AC	SIMPLE CYCLE COMBUSTION TURBINES	WATER INJECTION AND LOW OPERATING HOURS	20	PPM
FL-0279	TEC/POLK POWER ENERGY STATION	PSD-FL-363	SIMPLE CYCLE GAS TURBINE	DRY LOW NOX	9	PPMVD @ 15% O2
FL-0280	TREASURE COAST ENERGY CENTER	PSD-FL-353	COMBINED CYCLE COMBUSTION TURBINE	SELECTIVE CATALYTIC REDUCTION (SCR)	2	PPMVD
FL-0285	PROGRESS BARTOW POWER PLANT	PSD-FL-381 AND 1030011-010-AC	SIMPLE CYCLE COMBUSTION TURBINE (ONE UNIT)	WATER INJECTION DRY LOW NOX	15	PPMVD

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
FL-0285	PROGRESS BARTOW POWER PLANT	PSD-FL-381 AND 1030011-010-AC	COMBINED CYCLE COMBUSTION TURBINE SYSTEM (4-ON-1)	WATER INJECTION	15	PPMVD UNCORRECTED
FL-0286	FPL WEST COUNTY ENERGY CENTER	PSD-FL-354 AND 0990646-001-AC	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	DRY LOW NOX AND SCR WATER INJECTION	2	PPMVD @15%O2
FL-0287	OLEANDER POWER PROJECT	PSD-FL-377 AND 0090180-003-AC	SIMPLE CYCLE COMBUSTION TURBINE	DLN COMBUSTORS WATER INJECTION	9	PPM @15% O2
FL-0300	JACKSONVILLE ELECTRIC AUTHORITY/JEA	0310047-015-AC AND PSD-FL-386	SIMPLE CYCLE TURBINE 172 MW	NATURAL GAS AS PRIMARY FUEL WITH 0.05% SULFUR DISTILLATE AS BACKUP. USES WATER INJECTION WHEN FIRING OIL.	15	PPM @ 15% 02 (GAS)
FL-0304	CANE ISLAND POWER PARK	PSD-FL-400 (0970043-014-AC)	300 MW COMBINED CYCLE COMBUSTION TURBINE	SCR	2	PPMVD
FL-0305	OUC CURTIS H. STANTON ENERGY CENTER	PSD-FL-373A AND 0950137-020-AC	300 MW COMBINED CYCLE COMBUSTION TURBINE	LOW NOX BURNERS AND SCR WATER INJECTION	8	PPMVD @15% O2
FL-0310	SHADY HILLS GENERATING STATION	PSD-FL-402	TWO SIMPLE CYCLE COMBUSTION TURBINE - MODEL 7FA	FIRING NATURAL GAS AND USING DLN 2.6 COMBUSTORS TO MINIMIZE NOX EMISSSIONS.	9	PPMVD @ 15% O2
FL-0313	AUBURNDALE CITRUS FACILITY	1050023-020-AC (PSD-FL-365)	COGEN SYSTEM TURBINE NO. 1 W/EXISTING DUCT BURNER #1	DRY LOW NOX BURNERS	25	PPMVD
FL-0313	AUBURNDALE CITRUS FACILITY	1050023-020-AC (PSD-FL-365)	COGEN SYSTEM TURBINE #2 W/EXISTING DUCT BURNER #2	DRY LOW NOX BURNERS	25	PPMVD
FL-0314	LEESBURG CITRUS FACILITY	0690002-012-AC (PSD-FL-366)	COGEN SYSTEM TURBINE & EXISTING STEAM GENERATOR	DRY LOW NOX BURNER	25	PPMVD
FL-0319	GREENLAND ENERGY CENTER	PSD-FL-401	190 MW Combustion Turbine	DLN Combustion System when firing natural gas and water injection system when firing fuel oil.	9	PPMVD @15% O2 (GAS)
GA-0138	LIVE OAKS POWER PLANT	4911-127-0075-P-02-0	COMBINED CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	DRY LOW NOx BURNERS, SELECTIVE CATALYTIC REDUCTION	2.5	PPM@15%02
GA-0139	DAHLBERG COMBUSDTION TURBINE ELECTRIC GENERATING FACILITY (P	4911-157-0034-V-04-1	SIMPLE CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	DRY LOW NOX BURNERS (FIRING NATURAL GAS). WATER INJECTION (FIRING FUEL OIL).	9	PPM@15%02
GA-0139	DAHLBERG COMBUSDTION TURBINE ELECTRIC GENERATING FACILITY (P	4911-157-0034-V-04-1	SIMPLE CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	DRY LOW NOx BURNERS (FIRING NATURAL GAS), WATER INJECTION (FIRING FUEL OIL).	297	T/YR
ID-0018	LANGLEY GULCH POWER PLANT	P-2009.0092	COMBUSTION TURBINE, COMBINED CYCLE W/ DUCT BURNER	SELECTIVE CATALYTIC REDUCTION (SCR), DRY LOW NOX (DLN), GOOD COMBUSTION PRACTICES (GCP)	2	PPMVD
KS-0028	NEARMAN CREEK POWER STATION	C-5780	COMBUSTION TURBINE #4 FACILITY	DRY LOW-NOX COMBUSTION TECHNOLOGY WILL BE USED TO CONTROL NITROGEN OXIDE EMISSIONS WHEN FIRING THE PRIMARY FUEL OF NATURAL GAS. WATER INJECTION WILL BE USED TO CONTROL NOX EMISSIONS WHEN FIRING NO. 2 FUEL OIL AS A BACKUP.	9	PPM (15% OXYGEN)
LA-0136	PLAQUEMINE COGENERATION FACILITY	PSD-LA-659(M2)	(4) GAS TURBINES/DUCT BURNERS	DRY LOW NOX BURNERS, SELECTIVE CATALYTIC REDUCTION	240	LB/H
LA-0192	CRESCENT CITY POWER	PSD-LA-704	GAS TURBINES - 187 MW (2)	LOW NOX BURNERS AND SELECTIVE CATLYTIC REDUCTION (SCR) ADD-ON CONTROLS	21.8	LB/H
LA-0194	SABINE PASS LNG TERMINAL	PSD-LA-703	30 MW GAS TURBINE GENERATORS (4)	DRY LOW NOX BURNER TECHNOLOGY	25	PPMD@15%02

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
LA-0194	SABINE PASS LNG TERMINAL	PSD-LA-703	30 MW GAS TURBINE GNERATORS (4) LOW LOAD OPERATIONS	DRY LOW NOX BURNER	50	PPMVD @ 15% O2
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	PSD-LA-714	GAS TURBINE GENERATOR NOS. 1-4	DRY LOW EMISSIONS (DLE) COMBUSTION TECHNOLOGY WITH LEAN PREMIX OF AIR AND FUEL	29	LB/H
LA-0224	ARSENAL HILL POWER PLANT	PSD-LA-726	SCN-3 COLD STARTUP CTG-1 SCN-7 COLD STARTUP CTG 2	COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTURE¿S RECOMMENDED PROCEDURES.	400	LB/H
LA-0224	ARSENAL HILL POWER PLANT	PSD-LA-726	SCN-5 SHUTDOWN CTG-1 / SCN-9 SHUTDOWN CTG-2	COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTURE¿S RECOMMENDED PROCEDURES.	400	LB/H
LA-0224	ARSENAL HILL POWER PLANT	PSD-LA-726	TWO COMBINED CYCLE GAS TURBINES	LOW NOX TURBINES, DUCT BURNERS COMBINED WITH SCR	30.15	LB/H
LA-0224	ARSENAL HILL POWER PLANT	PSD-LA-726	SCN-4 HOT STARTUP CTG-1 SCN-8 HOT STARTUP CTG-2	COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTURE¿S RECOMMENDED PROCEDURES.	400	LB/H
LA-0232	STERLINGTON COMPRESSOR STATION	PSD-LA-729	COMPRESSOR TURBINE NO. 1	DRY LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	0.057	LB/MMBTU
LA-0232	STERLINGTON COMPRESSOR STATION	PSD-LA-729	COMPRESSOR TURBINE NO. 2	DRY LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	0.057	LB/MMBTU
LA-0257	SABINE PASS LNG TERMINAL	PSD-LA-703(M3)	Simple Cycle Refrigeration Compressor Turbines (16)	water injection	22.94	LB/H
LA-0257	SABINE PASS LNG TERMINAL	PSD-LA-703(M3)	Simple Cycle Generation Turbines (2)	water injection	28.68	LB/H
LA-0257	SABINE PASS LNG TERMINAL	PSD-LA-703(M3)	Combined Cycle Refrigeration Compressor Turbines (8)	water injection	22.94	LB/H
LA-0258	CALCASIEU PLANT	PSD-LA-746	TURBINE EXHAUST STACK NO. 1 & NO. 2	DRY LOW NOX COMBUSTORS	240	LB/H
MA-0035	THOMAS H. WATSON GENERATING STATION	049-119-MA10	SIMPLE-CYCLE GAS TURBINE		0	
MD-0031	CHALK POINT	CPCN CASE NO. 8912	GE 7EA COMBUSTION TURBINE - NG, SC ONLY	LOW NOX COMBUSTORS AND WATER INJECTION	9	PPMVD
MD-0031	CHALK POINT	CPCN CASE NO. 8912	GE 7EA COMBUSTION TURBINE - FO, SC ONLY	ADVANCED DRY LOW NOX COMBUSTORS AND WATER INJECTION	42	PPMVD @ 15% O2
MD-0035	DOMINION	009-5-0049	COMBUSTION TURBINE	DRY LOW-NOX COMBUSTORS AND SCR	2.5	PPMVD
MD-0036	DOMINION	CPCN 9055	COMBUSTION TURBINE	LNB AND SCR	5	PPMVD
MD-0036	DOMINION	CPCN 9055	COMBUSTION TURBINE	EXCLUSIVE USE OF LNG QUALITY, LOW SULFUR NATURAL GAS; LNB AND SCR	5	PPMVD
MD-0040	CPV ST CHARLES	CPCN CASE NO. 9129	COMBUSTION TURBINES (2)	DRY LOW NOX BURNER AND SCR	2	PPMVD @ 15% O2

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
MI-0327	INDECK-NILES, LLC	364-00A	4 GAS TURBINES WITH HEAT RECOVERY STEAM GENERATORS	DRY LOW NOX BURNERS AND SELECTIVE CATALYTIC REDUCTION.	3.5	PPMDV @ 15% O2
MI-0366	BERRIEN ENERGY, LLC	323-01A	3 COMBUSTION TURBINES AND DUCT BURNERS	DRY LOW NOX BURNERS AND SELECTIVE CATALYTIC REDUCTION.	2.5	PPMDV @ 15% O2
MN-0052	GREAT RIVER ENERGY LAKEFIELD JUNCTION STATION	09100058-003	TURBINE, SIMPLE CYCLE, NATURAL GAS	DRY LOW NOX, GOOD COMBUSTION PRACTICE	9	PPM @ 15% O2
MN-0052	GREAT RIVER ENERGY LAKEFIELD JUNCTION STATION	09100058-003	TURBINE, SIMPLE CYCLE, FUEL OIL	WATER INJECTION GOOD COMBUSTION PRACTICES	42	PPM @ 15% O2
MN-0053	FAIRBAULT ENERGY PARK	13100071-001	TURBINE, SIMPLE CYCLE, NATURAL GAS (1)	DRY LOW-NOX COMBUSTORS OPERATING IN LEAN PREMIX MODE.	25	PPMVD @ 15% 02
MN-0053	FAIRBAULT ENERGY PARK	13100071-001	TURBINE, SIMPLE CYCLE, DISTILLATE OIL (1)	WATER INJECTION	42	PPMVD @ 15% 02
MN-0053	FAIRBAULT ENERGY PARK	13100071-001	TURBINE, COMBINED CYCLE, NATURAL GAS (1)	SCR AND DLN.	3	PPMVD @ 15% 02
MN-0053	FAIRBAULT ENERGY PARK	13100071-001	TURBINE, COMBINED CYCLE, DISTILLATE OIL (1)	SCR AND WATER INJECTION.	6	PPMVD @ 15% 02
MN-0054	MANKATO ENERGY CENTER	01300098-001	COMBUSTION TURBINE, LARGE 2 EACH	WATER INJECTION AND SCR	5.5	PPMVD @15% 02
MN-0054	MANKATO ENERGY CENTER	01300098-001	COMBUSTION TURBINE, LARGE, 2 EACH	LEAN PRE-MIX COMBUSTION & SCR	3	PPMVD 15% 02
MN-0071	FAIRBAULT ENERGY PARK	13100071-003	COMBINED CYCLE COMBUSTION TURBINE W/DUCT BURNER	DRY LOW NOX COMBUSTION FOR NG; WATER INJECTION FOR NO.2 OIL; SCR W/NHZ INJECTION IN HRSG FOR BOTH NG & NO. 2 OIL.	3	PPMVD
MN-0075	GREAT RIVER ENERGY - ELK RIVER STATION	14100003-004	COMBUSTION TURBINE GENERATOR	DRY LOW-NOX COMBUSTION WHEN COMBUSTING NATURAL GAS	9	PPM
MN-0075	GREAT RIVER ENERGY - ELK RIVER STATION	14100003-004	COMBUSTION TURBINE GENERATOR	WATER INJECTION WHEN COMBUSTING FUEL OIL	42	PPM
MO-0067	SOUTH HARPER PEAKING FACILITY	122004-017	TURBINES, SIMPLE CYCLE, NATURAL GAS, (3)	DRY-LOW NOX BURNERS	15	PPM
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	1380-00015	EMISSION POINT AA-001		12	PPM @ 15% 02
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	1380-00015	EMISSION POINT AA-002		12	PPM @ 15
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	1380-00015	EMISSION POINT AA-003		12	PPM @ 15% 02
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	1380-00015	EMISSION POINT AA-004		12	PPM @ 15% 02
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	1380-00015	GENERAL ELECTRIC COMBUSTION TURBINES		42	PPM @ 15% 02

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	1380-00015	GENERAL ELECTRIC COMBUSTION TURBINES		42	PPM @ 15% 02
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	1380-00015	GENERAL ELECTRIC COMBUSTION TURBINES		42	PPM @ 15% 02
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	1380-00015	GENERAL ELECTRIC COMBUSTION TURBINES		42	PPM @ 15% 02
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, LLC	0444-00018	EMISSION POINT AA-001 GEN. ELEC. COMBUST. TURBINE	SCR	3.5	PPMV @ 15% 02
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, LLC	0444-00018	EMISSION POINT AA-002 GEN ELEC. COMB. TURBINE	SCR	3.5	PPMV @ 15% 02
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, LLC	0444-00018	EMISSION POINT AA-003 GEN. ELEC COMB TURBINES	SCR	3.5	PPMV @ 15 02
MS-0074	MOSELLE PLANT	1360-00035A	COMBUSTION TURBINE, GAS-FIRED, SIMPLE-CYCLE	DRY, LOW-NOX BURNER WITH INLET GAS COOLING.	9	PPM VD @ 15% O2
NC-0101	FORSYTH ENERGY PLANT	00986R1	TURBINE, COMBINED CYCLE, NATURAL GAS, (3)	DRY LOW-NOX COMBUSTORS AND SELECTIVE CATALYTIC REDUCTION (SCR)	2.5	PPM @ 15% O2
NC-0101	FORSYTH ENERGY PLANT	00986R1	TURBINE, COMBINED CYCLE, FUEL OIL, (3)	DRY LOW NOX COMBUSTORS AND USE OF WATER INJECTION.	8	PPM @ 15% O2
NE-0021	CASS COUNTY POWER PLANT	70919C01	2-173 MW COMBUSTION TURBINES	DLN	136	LB/H
NE-0022	C. W. BURDICK GENERATING STATION	54712C01	GAS-FIRED COMBUSTION TURBINE	DLN COMBUSTION	30	LB/H
NH-0014	UNIVERSITY OF NEW HAMPSHIRE	TP-B-0531	LANDFILL GAS/ NAT GAS COMBUSTION TURBINE	DRY LOW NOX (ULTRA LEAN PREMIX) COMBUSTION TECHNOLOGY GOOD COMBUSTION PRACTICES	5	PPM @ 15% O2
NJ-0066	AES RED OAK LLC	BOP 050001	COMBINED CYCLE NATURAL GAS FIRED COMBUSTION TURBINES(3)	SELECTIVE CATALYTIC REDUCTION(SCR) FOR EACH TURBINE.	25.3	LB/H
NJ-0074	WEST DEPTFORD ENERGY	56078-BOP080001	TURBINE, COMBINED CYCLE	SELECTIVE CATALYTIC REDUCTION AND WATER INJECTION	0.01	LB/MMBTU
NJ-0075	BAYONNE ENERGY CENTER	12863- BOP080001	COMBUSTION TURBINES, SIMPLE CYCLE , ROLLS ROYCE, 8	SELECTIVE CATALYTIC REDUCTION SYSTEM (SCR) AND WET LOW-EMISSION (WLE) COMBUSTORS SUBJECT TO LAER	2.5	PPMVD@15%O2
NJ-0076	PSEG FOSSIL LLC KEARNY GENERATING STATION	12200-BOP100002	SIMPLE CYCLE TURBINE	SCR and Use of Clean Burning Fuel: Natural gas	2.5	PPMVD@15%O2
NV-0033	EL DORADO ENERGY, LLC	A-00652	COMBUSTION TURBINE, COMBINED CYCLE & COGEN(2)	LOW NOX BURNER + SCR	3.5	PPM @ 15% O2
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	AP4911-1504	TURBINE, COMBINED CYCLE COMBUSTION #2 WITH HRSG AND DUCT BURNER.	SELECTIVE CATALYTIC REDUCTION WITH AMMONIA INJECTION	2	PPM @ 15% O2
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	AP4911-1504	TURBINE, COMBINED CYCLE COMBUSTION #1 WITH HRSG AND DUCT BURNER.	SELECTIVE CATALYST REDUCTION W/ AMMONIA INJECTION	2	PPM @ 15% O2

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
NV-0036	TS POWER PLANT	AP4911-1349	35 MW COMBUSTION TURBINES	SCR & WATER INJECTION	6	PPMVD
NV-0037	COPPER MOUNTAIN POWER	15347	LARGE COMBUSTION TURBINES, COMBINED CYCLE & COGENERATION	DRY LOW-NOX COMBUSTOR, STEAM INJECTION, AND SELECTIVE CATALYTIC REDUCTION	2	PPMVD
NV-0038	IVANPAH ENERGY CENTER, L.P.	1616	LARGE COMBUSTION TURBINES, COMBINED CYCLE & COGENERATION	DRY LOW NOX COMBUSTION CONTROL IN COMBINATION WITH SELECTIVE CATALYTIC REDUCTION	2	PPMVD
NV-0046	GOODSPRINGS COMPRESSOR STATION	468	LARGE COMBUSTION TURBINE - SIMPLE CYCLE	THE SOLONOX BURNER IN EACH TURBINE UTILIZES THE DRY LOW-NOX TECHNOLOGY TO CONTROL NOX EMISSIONS.	25	PPMVD
NV-0048	GOODSPRINGS COMPRESSOR STATION	468	SIMPLE-CYCLE SMALL COMBUSTION TURBINES (<25 MW)	SOLONOX - A DRY LOW NOX TECHNOLOGY THAT REDUCES THE CONVERSION OF ATMOSPHERIC NITROGEN TO NOX BY OPERATING AT RELATIVELY LOW FUEL-TO-AIR RATIOS TO LOWER THE COMBUSTION TEMPERATURE IN THE TURBINE.	25	PPMVD
NV-0050	MGM MIRAGE	825	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	LEAN PRE-MIX TECHNOLOGY AND LIMITING THE FUEL TO NATURAL GAS ONLY	0.178	LB/MMBTU
NY-0095	CAITHNES BELLPORT ENERGY CENTER	PSD-NY-0001	COMBUSTION TURBINE	SCR	2	PPMVD@15%02
NY-0095	CAITHNES BELLPORT ENERGY CENTER	PSD-NY-0001	COMBUSTION TURBINE	SCR	6	PPMVD@15%02
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	07-00503	TURBINES (4) (MODEL GE 7FA), DUCT BURNERS ON	DRY LOW NOX (DLN) BURNERS AND SELECTIVE CATALYTIC REDUCTION (SCR)	27.8	LB/H
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	07-00503	TURBINES (4) (MODEL GE 7FA), DUCT BURNERS OFF	DRY LOW NOX (DLN) BURNERS AND SELECTIVE CATALYTIC REDUCTION(SCR)	21.1	LB/H
OH-0253	DAYTON POWER AND LIGHT COMPANY	08-04380	COMBUSTION TURBINE (1), SIMPLE CYCLE	DRY LOW NOX burners	62	LB/H
OH-0253	DAYTON POWER AND LIGHT COMPANY	08-04380	COMBUSTION TURBINES (2), SIMPLE CYCLE		113	LB/H
OH-0253	DAYTON POWER AND LIGHT COMPANY	08-04380	COMBUSTION TURBINES (2), SIMPLE CYCLE	WATER INJECTION	195	LB/H
OH-0253	DAYTON POWER AND LIGHT COMPANY	08-04380	COMBUSTION TURBINE (1), SIMPLE CYCLE	WATER INJECTION	195	LB/H
OH-0291	OHIO EDISON CO.-WEST LORAIN PLANT	02-13376	SIMPLE CYCLE COMBUSTION TURBINES (5) W/ NATURAL GAS	DRY LOW NOX BURNERS	143	LB/H
OH-0291	OHIO EDISON CO.-WEST LORAIN PLANT	02-13376	SIMPLE CYCLE COMBUSTION TURBINES (5) W/ DISTILLATE OIL	WATER INJECTION INTO COMBUSTION ZONE	215	LB/H
OH-0304	ROLLING HILLS GENERATING PLANT	06-07747	NATURAL GAS FIRED TURBINES (5)	DRY LOW NOX BURNERS	117	LB/H
OH-0333	DAYTON POWER & LIGHT ENERGY LLC	P0104867	Turbines (4), simple cycle, natural gas	dry low NOx burners	161	LB/H
OH-0333	DAYTON POWER & LIGHT ENERGY LLC	P0104867	Turbines (4), simple cycle, fuel oil #2	Water injection	269	LB/H

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
OK-0115	LAWTON ENERGY COGEN FACILITY	2001-205-C M-1 PSD	COMBUSTION TURBINE AND DUCT BURNER	SCR W/ DRY LOW NOX BURNERS AND DRY LOW NOX COMBUSTION	3.5	PPMVD
OK-0117	PSO SOUTHWESTERN POWER PLT	2003-403-C PSD	GAS-FIRED TURBINES	DRY LOW NOX	9	PPM
OK-0120	PSO RIVERSIDE JENKS POWER STA	2003-360-C M-1 PSD	COMBUSTION TURBINES	DRY-LOW NOX BURNERS	9	PPMVD
OK-0127	WESTERN FARMERS ELECTRIC ANADARKO	2005-037-C(M-2) PSD	COMBUSTION TURBINE PEAKING UNIT(S)	WATER INJECTION	25	PPM
OR-0039	COB ENERGY FACILITY, LLC	18-0029	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, (4)	DLN COMBUSTORS, AND SCR	2.5	PPMVD @ 15% O2
OR-0041	WANAPA ENERGY CENTER	R10PSD-OR-05-01	COMBUSTION TURBINE & HEAT RECOVERY STEAM GENERATOR	DRY LOW-NOX BURNERS AND SCR.	2	PPMDV @ 15% O2
OR-0043	UMATILLA GENERATING COMPANY, L.P.	30-0007	TURBINE, COMBINED CYCLE & DUCT BURNER, NAT GAS (2)	DLN COMBUSTORS AND SCR	2	PPMVD @ 15% O2
PR-0008	PREPA	TV-4911-30-1196-0013	TURBINE, COMBINED CYCLE (2)	STEAM INJECTION	34.2	PPM @ 15% O2
RI-0023	RHODE ISLAND CENTRAL GENCO, LLC	RI-PSD-8	LANDFILL GAS-FIRED COMBUSTION TURBINE	SELECTIVE CATALYTIC REDUCTION	25	PPMV
TX-0453	BAYPORT ENERGY CENTER	P1031	COMBUSTION TURBINE WITH 225 MMBTU/H DUCT BURNERS (2)	THE GAS TURBINES WILL BE EQUIPPED WITH DRY LOW NOX COMBUSTORS, AND THE DUCT BURNERS WILL CONTAIN LOW NOX BURNERS. NOX EMISSIONS WILL BE LIMITED AT THE STACK TO 3.5 PPMVD ON A THREE-HOUR BASIS AND 1.9 PPMVD ON AN ANNUAL BASIS	9	LB/H
TX-0454	EL PASO NATURAL GAS CORNUDAS COMPRESSOR STATION	P1030	TURBINES (2)	LOW NOX BURNERS	7.6	LB/H
TX-0469	TEXAS PETROCHEMICALS HOUSTON FACILITY	P999	TURBINE AND DUCT BURNER (3)	GOOD COMBUSTION AND SWEET NATURAL GAS	49.44	LB/H
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	PSD-TX-828M1	L-AREA GAS TURBINE		27.46	LB/H
TX-0497	INEOS CHOCOLATE BAYOU FACILITY	PSD-TX 983 AND 46192	COGENERATION TRAIN 2 AND 3 (TURBINE AND DUCT BURNER EMISSIONS)	BP AMOCO PROPOSES TO USE SCR TO CONTROL NOX EMISSIONS FROM BOTH TURBINES AND DUCT BURNERS AFTER CONSIDERING ALTERNATIVE NOX CONTROL METHODS. THE TURBINES AND DUCT BURNERS WILL ALSO USE LOW NOX COMBUSTORS. BP AMOCO PROPOSES	11.43	LB/H
TX-0498	SIGNAL HILLS WICHITA FALLS POWER LP	PSD-TX 685 AND 16750	TURBINES (3)		52	LB/H
TX-0501	TEXSTAR GAS PROCESS FACILITY	PSD-TX 55M3 AND 6051	ALLISON 501KB GAS TURBINE GENERATOR		10.5	LB/H
TX-0502	NACOGDOCHES POWER STERNE GENERATING FACILITY	PSD-TX 1015 AND 49293	WESTINGHOUSE/SIEMENS MODEL SW501F GAS TURBINE W/ 416.5 MMBTU DUCT BURNERS	STEAG POWER LLC IS PROPOSING THE USE OF DRY LOW NOX (DLN) COMBUSTORS FOR THE TURBINES AND LOW NOX BURNERS IN THE DUCT BURNERS ALONG WITH SELECTIVE CATALYST REDUCTION (SCR) SYSTEM FOR THE CONTROL OF NOX EMISSIONS FROM THE COMB	45.4	LB/H
TX-0504	NAVASOTA POWER GENERATION FACILITY	PSD-TX 1059/1060 AND 76990	TURBINES WITH 165 MMBTU/HR DUCT BURNERS	LOW NOX BURNERS	21.4	LB/H
TX-0504	NAVASOTA POWER GENERATION FACILITY	PSD-TX 1059/1060 AND 76990	TURBINES WITHOUT 165 MMBTU/HR DUCT BURNERS	LOW NOX BURNERS AND SCR	18.5	LB/H

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
TX-0504	NAVASOTA POWER GENERATION FACILITY	PSD-TX 1059/1060 AND 76990	STARTUP, SHUTDOWN, MAINTENANCE		600	LB/H
TX-0506	NRG TEXAS ELECTRIC POWER GENERATION	PSD-TX 1051 AND 21587	TURBINE FIRING NATURAL GAS W/ BURNERS	LOW NOX BURNERS AND SCR	106.5	LB/H
TX-0506	NRG TEXAS ELECTRIC POWER GENERATION	PSD-TX 1051 AND 21587	TURBINE FIRING NATURAL GAS W/O BURNERS	LOW NOX BURNERS AND SCR	62	LB/H
TX-0506	NRG TEXAS ELECTRIC POWER GENERATION	PSD-TX 1051 AND 21587	TURBINE FIRING FUEL OIL W/ BURNERS	SCR AND LOW NOX BURNERS	364.5	LB/H
TX-0506	NRG TEXAS ELECTRIC POWER GENERATION	PSD-TX 1051 AND 21587	TURBINE FIRING FUEL OIL W/O BURNERS	LOW NOX BURNERS AND SCR	320	LB/H
TX-0506	NRG TEXAS ELECTRIC POWER GENERATION	PSD-TX 1051 AND 21587	ANNUAL LIMITS		439.4	T/YR
TX-0509	PONDEROSA PINE ENERGY PARTNERS COGENERATION FACILITY	PSD-TX-839	TURBINE AND 375 MMBTU/HR HEAT RECOVERY STEAM SYSTEM		115.7	LB/H
TX-0525	TEXAS GENCO UNITS 1 AND2	PSD-TX 807 AND 21587	80 MW GAS TURBINE		62	LB/H
TX-0525	TEXAS GENCO UNITS 1 AND2	PSD-TX 807 AND 21587	80 MW GAS TURBINE		106.5	LB/H
TX-0525	TEXAS GENCO UNITS 1 AND2	PSD-TX 807 AND 21587	80 MW GAS TURBINE		364.5	LB/H
TX-0525	TEXAS GENCO UNITS 1 AND2	PSD-TX 807 AND 21587	80 MW GAS TURBINE		320	LB/H
TX-0551	PANDA SHERMAN POWER STATION	PSDTX1198	Natural Gas-fired Turbines	Dry low NOx combustors and Selective Catalytic Reduction	9	PPMVD
TX-0552	WOLF HOLLOW POWER PLANT NO. 2	PSDTX1110	Natural gas-fired turbines	Dry low NOx combustors plus selective catalytic reduction	2	PPMVD
TX-0590	KING POWER STATION	PSDTX1125	Turbine	DLN burners and SCR	2	PPMVD AT 15% O2
TX-0600	THOMAS C. FERGUSON POWER PLANT	PSDTX1244	Natural gas-fired turbines	Dry low NOx burners and Selective Catalytic Reduction	2	PPMVD
UT-0066	CURRANT CREEK	DAQE-2524002-04	NATURAL GAS FIRED TURBINES AND HEAT RECOVERY STEAM GENERATORS	CONVENTIONAL SELECTIVE CATALYTIC REDUCTION SYSTEM WITH AMMONIA INJECTION	2.25	PPMVD
VA-0287	JAMES CITY ENERGY PARK	61442	TURBINE, COMBINED CYCLE, NATURAL GAS,DUCT BURNER	DRY LOW NOX BURNERS, SCR WITH AMMONIA INJECTION AND CEM DEVICES	2.5	PPM
VA-0287	JAMES CITY ENERGY PARK	61442	TURBINE, COMBINED CYCLE, NATURAL GAS	DRY LOW NOX BURNERS SCR WITH AMMONIA INJECTION AND CEM DEVICES.	2.5	PPM
VA-0287	JAMES CITY ENERGY PARK	61442	TURBINE, COMBINED CYCLE, FUEL OIL	DRY LOW NOX BURNERS SCR WITH AMMONIA INJECTION AND CEM DEVICES.	6	PPM

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
VA-0289	DUKE ENERGY WYTHE, LLC	11382	TURBINE, COMBINED CYCLE, NATURAL GAS	SCR AND LOW NOX BURNERS. GOOD COMBUSTION PRACTICES.	2.5	PPMVD
VA-0289	DUKE ENERGY WYTHE, LLC	11382	TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	SCR AND LOW NOX BURNERS; GOOD COMBUSTION PRACTICES	2.5	PPMVD
VA-0291	CPV WARREN LLC	81391	TURBINE, COMBINED CYCLE (2)	TWO STAGE LEAN PERMIX DRY LOW NOX COMBUSTION SCR AND GOOD COMBUSTION PRACTICES.	2	PPM
VI-0012	VIWAPA - ST. THOMAS	NOT PROVIDED	TURBINE, SIMPLE CYCLE	STEAM/WATER INJECTION; LIMIT OF N2 TO 1000 PPM	135	LB/H
WA-0316	NORTHWEST PIPELINE CORP.-MT VERNON COMPRESSOR	PSD-01-09 AMENDMENT 5	TURBINE, SIMPLE CYCLE	DRY LOW NOX COMBUSTORS	25	PPMDV
WA-0316	NORTHWEST PIPELINE CORP.-MT VERNON COMPRESSOR	PSD-01-09 AMENDMENT 5	TURBINE, SIMPLE CYCLE	DRY LOW NOX COMBUSTION	25	PPMVD @ 15% O2
WA-0328	BP CHERRY POINT COGENERATION PROJECT	EFSEC/2002-01	GE 7FA COMBUSTION TURBINE & HEAT RECOVERY STEAM GENERATOR	LEAN PRE-MIX DRY LOW-NOX BURNERS ON CT. LOW-NOX DUCT BURNERS. SCR.	2.5	PPMDV
WI-0227	PORT WASHINGTON GENERATING STATION	04-RV-175	COMBINED CYCLE COMBUSTION TURBINES (4 W/ DUCT BURNER, HRSG)	NATURAL GAS, DRY LOW NOX BURNERS, SELECTIVE CATALYTIC REDUCTION (SCR)	3	PPM @15% O2
WI-0240	WE ENERGIES CONCORD	05-SDD-320	COMBUSTION TURBINE, 100 MW, NATURAL GAS	WATER INJECTION	25	PPMDV @ 15% O2
WI-0240	WE ENERGIES CONCORD	05-SDD-320	COMBUSTION TURBINE, 100 MW, #2 FUEL OIL	WATER INJECTION	65	PPMDV @ 15% O2
WY-0066	MEDICINE BOW IGL PLANT	CT-5873	COMBUSTION TURBINE 1	SCR	4	PPM @ 15% O2
WY-0066	MEDICINE BOW IGL PLANT	CT-5873	COMBUSTION TURBINE 2	SCR	4	PPM @ 15% O2
WY-0066	MEDICINE BOW IGL PLANT	CT-5873	COMBUSTION TURBINE 3	SCR	4	PPM @ 15% O2
WY-0067	ECHO SPRINGS GAS PLANT	MD-7837	TURBINES S35-S36	SOLONOX	15	PPMV
WY-0067	ECHO SPRINGS GAS PLANT	MD-7837	TURBINE S34	SOLONOX	25	PPMV
WY-0067	ECHO SPRINGS GAS PLANT	MD-7837	TURBINE S37	GOOD COMBUSTION PRACTICES	15	PPMV

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
*SD-0005	DEER CREEK STATION	28.0505-PSD	Combustion turbine/heat recovery steam generator	Catalytic oxidation	10.5	POUNDS PER HOUR
AK-0062	BADAMI DEVELOPMENT FACILITY	AQ0417CPT05, REVISION 1	SOLAR MARS 90 TURBINE	GOOD COMBUSTION PRACTICES	385	LB/H
AK-0066	ENDICOTT PRODUCTION FACILITY, LIBERTY DEVELOPMENT PROJECT	AQ0181CPT06, REVISION 2	EU ID 10A, TURBINE	CATALYTIC OXIDATION	5	PPMV @ 15% O2
AL-0208	EXXON MOBILE BAY -- NORTHWEST GULF FIELD	503-0013-X00	TURBINE, SIMPLE CYCLE		50	PPM @ 15% O2
AL-0209	EXXON MOBILE -- MOBILE BAY - BON SECURE BAY FIELD	503-0012-X005	TURBINE, SIMPLE CYCLE		50	PPM @ 15% O2
AL-0251	HILLABEE ENERGY CENTER	310-0022-X001	COMBUSTINE TURBINE (WITH DUCT BURNING)	GOOD COMBUSTION PRACTICES	194	LB/H
AL-0251	HILLABEE ENERGY CENTER	310-0022-X001	COMBUSTION TURBINE (WITHOUT DUCT BURNING)	GOOD COMBUSTION PRACTICES	59.6	LB/H
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	S01-004	TURBINE, COMBINED CYCLE & DUCT BURNER	CATALYTIC OXIDIZER	3	PPM @ 15% O2
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	S01-004	TURBINE, COMBINED CYCLE	CATALYTIC OXIDIZER	2	PPM @ 15% O2
AZ-0047	WELLTON MOHAWK GENERATING STATION	1001653	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - SW501F TURBINES OPTION	OXIDATION CATALYST	3	PPM @ 15% O2
AZ-0047	WELLTON MOHAWK GENERATING STATION	1001653	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - GE7FA TURBINES OPTION	OXIDATION CATALYST	3	PPM @ 15% O2
CA-1051	THREE MOUNTAIN POWER, LLC	99-PO-01	GAS TURBINE: COMBINED CYCLE >= 50 MW	SCR SYSTEM, AND OXIDATION CATALYST	4	PPMVD @ 15% O2
CA-1052	WESTERN MIDWAY SUNSET POWER PROJECT	S-1135-313-0	GAS TURBINE: COMBINED CYCLE >= 50 MW	SCR SYSTEM, AND OXIDATION CATALYST	4	PPMVD @ 15% O2
CA-1142	PASTORIA ENERGY FACILITY	SJ 99-03	3 COMBUSTION TURBINES	XONON CATALYTIC COMBUSTORS OR DRY LOW NOX BURNERS & SCR	6	PPMVD
CA-1143	SUTTER POWER PLANT	SAC 98-01	2 COMBUSTION TURBINES	OXIDATION CATALYST SYSEM	4	PPMVD
CA-1144	BLYTHE ENERGY PROJECT II	SE 02-01	2 COMBUSTION TURBINES		4	PPMVD
CO-0056	ROCKY MOUNTAIN ENERGY CENTER, LLC	05WE0524	NATURAL-GAS FIRED, COMBINED-CYCLE TURBINE	USE GOOD COMBUSTION CONTROL PRACTICES AND CATALISTIC OXIDATION.	3	PPM @ 15% O2
CO-0058	CHEYENNE STATION	03WE0910303-	FREP TURBINE	GOOD COMBUSTION PRACTICES (SEE NOTES)	25	PPMVD
CO-0058	CHEYENNE STATION	03WE0910303-	CPP TURBINES	SOLONOX COMBUSTION DESIGN (DRY LOW NOX) (DETEMINED TECHNICALLY INFEASIBLE - SEE NOTES)	24.5	PPM @ 15% O2
CO-0059	CHEYENNE STATION	04WE1390	PHASE II TURBINE	GOOD COMBUSTION PRACTICES	25	PPM @ 15% O2

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
CT-0151	KLEEN ENERGY SYSTEMS, LLC	104-0131 AND 104-0133	SIEMENS SGT6-5000F COMBUSTION TURBINE #1 AND #2 (NATURAL GAS FIRED) WITH 445 MMBTU/HR NATURAL GAS DUCT BURNER	CO CATLYST	4.3	LB/H
CT-0151	KLEEN ENERGY SYSTEMS, LLC	104-0131 AND 104-0133	SIEMENS SGT6-5000F COMBUSTION TURBINE #1 AND #2 (OIL FIRED) WITH 445 MMBTU/HR NATURAL GAS DUCT BURNER	CO CATALYST	7.3	LB/H
FL-0261	ARVAH B. HOPKINS GENERATING STATION	PSD-FL-343	TURBINE, SIMPLE CYCLE, NATURAL GAS, (2)	OXIDATION CATALYST	6	PPMDV @ 15% O2
FL-0261	ARVAH B. HOPKINS GENERATING STATION	PSD-FL-343	TURBINE, SIMPLE CYCLE (2) FUEL OIL	OXIDATION CATALYST	6	PPMVD @ 15 % O2
FL-0263	FPL TURKEY POINT POWER PLANT	PSD-FL-338	170 MW COMBUSTION TURBINE, 4 UNITS	CO WILL BE MINIMIZED BY THE EFFICIENT COMBUSTION OF NATURAL GAS AND DISTILLATE OIL AT HIGH TEMPERATURES	8	PPMVD @ 15 % O2
FL-0265	HINES POWER BLOCK 4	PSD-FL-342 AND 1050234-010-AC	COMBINED CYCLE TURBINE	GOOD COMBUSTION	8	PPM
FL-0272	STOCK ISLAND POWER PLANT (KEYS ENERGY)	0870003-007-AC AND PSD-FL-348	SIMPLE CYCLE COMBUSTION TURBINE	GOOD COMBUSTION	30	PPMVD@15%O2
FL-0280	TREASURE COAST ENERGY CENTER	PSD-FL-353	COMBINED CYCLE COMBUSTION TURBINE	GOOD COMBUSTION	6	PPM
FL-0285	PROGRESS BARTOW POWER PLANT	PSD-FL-381 AND 1030011-010-AC	SIMPLE CYCLE COMBUSTION TURBINE (ONE UNIT)	GOOD COMBUSTION	8	PPMVD
FL-0285	PROGRESS BARTOW POWER PLANT	PSD-FL-381 AND 1030011-010-AC	COMBINED CYCLE COMBUSTION TURBINE SYSTEM (4-ON-1)	GOOD COMBUSTION	8	PPMVD
FL-0286	FPL WEST COUNTY ENERGY CENTER	PSD-FL-354 AND 0990646-001-AC	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS		8	PPMVD @15%O2
FL-0304	CANE ISLAND POWER PARK	PSD-FL-400 (0970043-014-AC)	300 MW COMBINED CYCLE COMBUSTION TURBINE	GOOD COMBUSTION PRACTICES	6	PPMVD
FL-0305	OUC CURTIS H. STANTON ENERGY CENTER	PSD-FL-373A AND 0950137-020-AC	300 MW COMBINED CYCLE COMBUSTION TURBINE	GOOD COMBUSTION	8	PPMVD @15%
FL-0310	SHADY HILLS GENERATING STATION	PSD-FL-402	TWO SIMPLE CYCLE COMBUSTION TURBINE - MODEL 7FA		6.5	PPMVD @ 15% O2 NG
FL-0319	GREENLAND ENERGY CENTER	PSD-FL-401	190 MW Combustion Turbine	Good Combustion	4.1	PPMVD @ 15% O2 (GAS)
GA-0127	PLANT MCDONOUGH COMBINED CYCLE	4911-067-0003-V-02-2	COMBINED CYCLE COMBUSTION TURBINE	OXIDATION CATALYST	1.8	PPM @ 15% O2
GA-0127	PLANT MCDONOUGH COMBINED CYCLE	4911-067-0003-V-02-2	COMBINED CYCLE COMBUSTION TURBINE	OXIDATION CATALYST	9	PPM@15% O2
GA-0138	LIVE OAKS POWER PLANT	4911-127-0075-P-02-0	COMBINED CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	GOOD COMBUSTION PRACTICES AND CATALYTIC OXIDATION	2	PPM@15%02
GA-0139	DAHLBERG COMBUSDTION TURBINE ELECTRIC GENERATING FACILITY (P	4911-157-0034-V-04-1	SIMPLE CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	GOOD COMBUSTION PRACTICES	9	PPM@15%02
HI-0021	MAALAEA GENERATING STATION	0067-01-C	COMBUSTION TURBINE, COMBINED CYCLE (2)	GOOD COMBUSTION DESIGN AND OPERATION.	44	PPMVD @ 15% O2

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
ID-0018	LANGLEY GULCH POWER PLANT	P-2009.0092	COMBUSTION TURBINE, COMBINED CYCLE W/ DUCT BURNER	CATALYTIC OXIDATION (CATOX), DRY LOW NOX (DLN), GOOD COMBUSTION PRACTICES (GCP)	2	PPMVD
KS-0028	NEARMAN CREEK POWER STATION	C-5780	COMBUSTION TURBINE #4 FACILITY	GOOD COMBUSTION PRACTIVES / DESIGN	25	PPM (15% OXYGEN)
LA-0136	PLAQUEMINE COGENERATION FACILITY	PSD-LA-659(M2)	(4) GAS TURBINES/DUCT BURNERS	GOOD COMBUSTION PRACTICES	212.5	LB/H
LA-0192	CRESCENT CITY POWER	PSD-LA-704	GAS TURBINES - 187 MW (2)	CO OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	17.7	LB/H
LA-0194	SABINE PASS LNG TERMINAL	PSD-LA-703	30 MW GAS TURBINE GENERATORS (4)	GOOD COMBUSTION PRACTICES	50	PPMVD@15%02
LA-0194	SABINE PASS LNG TERMINAL	PSD-LA-703	30 MW GAS TURBINE GNERATORS (4) LOW LOAD OPERATIONS	GOOD COMBUSTION PRACTICES	80	PPMVD @ 15% O2
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	PSD-LA-714	GAS TURBINE GENERATOR NOS. 1-4	DRY LOW EMISSIONS (DLE) COMBUSTION TECHNOLOGY WITH LEAN PREMIX OF AIR AND FUEL	17.8	LB/H
LA-0224	ARSENAL HILL POWER PLANT	PSD-LA-726	SCN-3 COLD STARTUP CTG-1 SCN-7 COLD STARTUP CTG-2	COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTURE¿S RECOMMENDED PROCEDURES.	1508.15	LB/H
LA-0224	ARSENAL HILL POWER PLANT	PSD-LA-726	SCN-5 SHUTDOWN CTG-1 / SCN-9 SHUTDOWN CTG-2	COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTURE¿S RECOMMENDED PROCEDURES.	964.57	LB/H
LA-0224	ARSENAL HILL POWER PLANT	PSD-LA-726	TWO COMBINED CYCLE GAS TURBINES	PROPER OPERATING PRACTICES	143.31	LB/H
LA-0224	ARSENAL HILL POWER PLANT	PSD-LA-726	SCN-4 HOT STARTUP CTG-1 SCN-8 HOT STARTUP CTG-2	COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTURE¿S RECOMMENDED PROCEDURES.	1575.8	LB/H
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	PSD-LA-752	COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B)	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	3	PPMVD @ 15% O2
LA-0257	SABINE PASS LNG TERMINAL	PSD-LA-703(M3)	Simple Cycle Refrigeration Compressor Turbines (16)	Good combustion practices and fueled by natural gas	43.6	LB/H
LA-0257	SABINE PASS LNG TERMINAL	PSD-LA-703(M3)	Simple Cycle Generation Turbines (2)	Good combustion practices and fueled by natural gas	17.46	LB/H
LA-0257	SABINE PASS LNG TERMINAL	PSD-LA-703(M3)	Combined Cycle Refrigeration Compressor Turbines (8)	Good combustion practices and fueled by natural gas	43.6	LB/H
LA-0258	CALCASIEU PLANT	PSD-LA-746	TURBINE EXHAUST STACK NO. 1 & NO. 2	DRY LOW NOX COMBUSTORS	781	LB/H
MD-0031	CHALK POINT	CPCN CASE NO. 8912	GE 7EA COMBUSTION TURBINE - NG, SC ONLY	GOOD COMBUSTION CONTROL	25	PPMVD
MD-0031	CHALK POINT	CPCN CASE NO. 8912	GE 7EA COMBUSTION TURBINE - FO, SC ONLY	GOOD COMBUSTION CONTROLS	20	PPMVD @ 15% O2
MD-0032	DICKERSON	CPCN CASE NO. 8888	UNIT 4 -GE FRAME 7F COM. TURBINES W/ HRSG - NG SC	OXIDATION CATALYST	84.2	LB/H
MD-0032	DICKERSON	CPCN CASE NO. 8888	UNIT 5 -GE FRAME 7F COM. TURBINES W/ HRSG - NG SC	OXIDATION CATALYST	32.2	LB/H

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
MD-0032	DICKERSON	CPCN CASE NO. 8888	UNIT 5 -GE FRAME 7F COMB. TURBINES W/ HRSG- FO SC	OXIDATION CATALYST	72.4	LB/H
MD-0032	DICKERSON	CPCN CASE NO. 8888	UNIT 4 -GE FRAME 7F COMB. TURBINES W/ HRSG- FO SC	OXIDATION CATALYST	85.3	LB/H
MD-0032	DICKERSON	CPCN CASE NO. 8888	UNIT 4 -GE FRAME 7F COMB. TURBINES W/ HRSG - NG CC	OXIDATION CATALYST	8.4	LB/H
MD-0032	DICKERSON	CPCN CASE NO. 8888	UNIT 5 -GE FRAME 7F COMB. TURBINES W/ HRSG - NG CC	OXIDATION CATALYST	7.6	LB/H
MD-0032	DICKERSON	CPCN CASE NO. 8888	UNIT 4 -GE FRAME 7F COMB. TURBINES W/ HRSG- FO CC	OXIDATION CATALYST	8.5	LB/H
MD-0032	DICKERSON	CPCN CASE NO. 8888	UNIT 5 -GE FRAME 7F COMB. TURBINES W/ HRSG- FO CC	OXIDATION CATALYST	7.2	LB/H
MD-0040	CPV ST CHARLES	CPCN CASE NO. 9129	COMBUSTION TURBINES (2)	OXIDATION CATALYST	2	PPMVD @ 15% O2
MI-0327	INDECK-NILES, LLC	364-00A	4 GAS TURBINES WITH HEAT RECOVERY STEAM GENERATORS	CATALYTIC OXIDATION SYSTEM	4	PPMVD@15% O2
MI-0366	BERRIEN ENERGY, LLC	323-01A	3 COMBUSTION TURBINES AND DUCT BURNERS	CATALYTIC OXIDATION.	2	PPMDV @ 15% O2
MN-0052	GREAT RIVER ENERGY LAKEFIELD JUNCTION STATION	09100058-003	TURBINE, SIMPLE CYCLE, NATURAL GAS	GOOD COMBUSTION PRACTICES - OPTIMIZED OPERATION OF GAS TURBINE	25	PPM @ 15% O2
MN-0052	GREAT RIVER ENERGY LAKEFIELD JUNCTION STATION	09100058-003	TURBINE, SIMPLE CYCLE, FUEL OIL	GOOD COMBUSTION PRACTICES - OPTIMIZED OPERATION	20	PPM @ 15% O2
MN-0053	FAIRBAULT ENERGY PARK	13100071-001	TURBINE, SIMPLE CYCLE, NATURAL GAS (1)	GOOD COMBUSTION PRACTICES.	10	PPMVD @ 15% 02
MN-0053	FAIRBAULT ENERGY PARK	13100071-001	TURBINE, SIMPLE CYCLE, DISTILLATE OIL (1)	GOOD COMBUSTION PRACTICES.	10	PPMVD @ 15% O2
MN-0053	FAIRBAULT ENERGY PARK	13100071-001	TURBINE, COMBINED CYCLE, NATURAL GAS (1)	GOOD COMBUSTION PRACTICES.	10	PPMVD @ 15% O2
MN-0053	FAIRBAULT ENERGY PARK	13100071-001	TURBINE, COMBINED CYCLE, DISTILLATE OIL (1)	GOOD COMBUSTION PRACTICES.	10	PPMVD @ 15% O2
MN-0054	MANKATO ENERGY CENTER	01300098-001	COMBUSTION TURBINE, LARGE 2 EACH	OXIDATION CATALYST AND GOOD COMBUSTION	4.8	PPMVD @15% 02
MN-0054	MANKATO ENERGY CENTER	01300098-001	COMBUSTION TURBINE, LARGE, 2 EACH	OXIDATION CATALYST AND GOOD COMBUSTION	4	PPMVD 15% 02
MN-0060	HIGH BRIDGE GENERATING PLANT	12300012-004	2 COMBINED-CYCLE COMBUSTION TURBINES	GOOD COMBUSTION PRACTICES	10	PPM @ 15% O2
MN-0066	NORTHERN STATES POWER CO. DBA XCEL ENERGY - RIVERSIDE PLANT	05300015-004	TURBINE, COMBINED CYCLE (2)	GOOD COMBUSTION PRACTICES	10	PPMVD @ 15% O2
MN-0071	FAIRBAULT ENERGY PARK	13100071-003	COMBINED CYCLE COMBUSTION TURBINE W/DUCT BURNER	GOOD COMBUSTION	9	PPMVD

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
MN-0075	GREAT RIVER ENERGY - ELK RIVER STATION	14100003-004	COMBUSTION TURBINE GENERATOR	GOOD COMBUSTION PRACTICES	4	PPM
MN-0075	GREAT RIVER ENERGY - ELK RIVER STATION	14100003-004	COMBUSTION TURBINE GENERATOR	GOOD COMBUSTION CONTROL	150	PPM
MN-0075	GREAT RIVER ENERGY - ELK RIVER STATION	14100003-004	COMBUSTION TURBINE GENERATOR	GOOD COMBUSTION CONTROL	250	PPM
MO-0067	SOUTH HARPER PEAKING FACILITY	122004-017	TURBINES, SIMPLE CYCLE, NATURAL GAS, (3)	GOOD COMBUSTION PRACTICES	25	PPMVD
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	1380-00015	EMISSION POINT AA-001		25	PPM @ 15% 02
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	1380-00015	EMISSION POINT AA-002		25	PPM @ 15 02
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	1380-00015	EMISSION POINT AA-003		25	PPM @ 15% 02
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	1380-00015	EMISSION POINT AA-004		25	PPM @ 15% 02
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	1380-00015	GENERAL ELECTRIC COMBUSTION TURBINES		20	PPM @ 15% 02
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	1380-00015	GENERAL ELECTRIC COMBUSTION TURBINES		20	PPM @ 15% 02
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	1380-00015	GENERAL ELECTRIC COMBUSTION TURBINES		20	PPM @ 15% 02
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	1380-00015	GENERAL ELECTRIC COMBUSTION TURBINES		20	PPM @ 15% 02
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, LLC	0444-00018	EMISSION POINT AA-001 GEN. ELEC. COMBUST. TURBINE	SCR	18.36	PPMV @ 1`5% 02
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, LLC	0444-00018	EMISSION POINT AA-002 GEN ELEC. COMB. TURBINE		18.36	PPMV @ 15% 02
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, LLC	0444-00018	EMISSION POINT AA-003 GEN. ELEC COMB TURBINES	SCR	18.36	PPMV @ 15 02
MS-0074	MOSELLE PLANT	1360-00035A	COMBUSTION TURBINE, GAS-FIRED, SIMPLE-CYCLE		20	PPM VD @ 15% O2
NC-0101	FORSYTH ENERGY PLANT	00986R1	TURBINE, COMBINED CYCLE, NATURAL GAS, (3)	GOOD COMBUSTION PRACTICES AND EFFICIENT PROCESS DESIGN.	11.6	PPM @ 15% O2
NC-0101	FORSYTH ENERGY PLANT	00986R1	TURBINE & DUCT BURNER, COMBINED CYCLE, NAT GAS, 3	GOOD COMBUSTION PRACTICES AND EFFICIENT PROCESS DESIGN	25.9	PPM @ 15% O2
NC-0101	FORSYTH ENERGY PLANT	00986R1	TURBINE, COMBINED CYCLE, FUEL OIL, (3)	EFFICIENT COMBUSTION PROCESS DESIGN.	15.7	PPM @ 15% O2
NC-0101	FORSYTH ENERGY PLANT	00986R1	TURBINE & DUCT BURNER, COMBINED CYCLE, FUEL OIL, 3	EFFICIENT COMBUSTION PROCESS DESIGN	25.1	PPM @ 15% O2

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
NE-0021	CASS COUNTY POWER PLANT	70919C01	2-173 MW COMBUSTION TURBINES	GOOD COMBUSTION PRACTICES	63	LB/H
NE-0022	C. W. BURDICK GENERATING STATION	54712C01	GAS-FIRED COMBUSTION TURBINE	GOOD COMBUSTION PRACTICES	34.7	LB/H
NH-0014	UNIVERSITY OF NEW HAMPSHIRE	TP-B-0531	LANDFILL GAS/ NAT GAS COMBUSTION TURBINE	GOOD COMBUSTION PRACTICES	10	PPM @ 15% O2
NJ-0066	AES RED OAK LLC	BOP 050001	COMBINED CYCLE NATURAL GAS FIRED COMBUSTION TURBINES(3)	OXIDATION CATALYST FOR EACH TURBINE.	20.69	LB/H
NJ-0074	WEST DEPTFORD ENERGY	56078-BOP080001	TURBINE, COMBINED CYCLE	CO OXIDATION CATALYST	0.01	LB/MMBTU
NJ-0075	BAYONNE ENERGY CENTER	12863- BOP080001	COMBUSTION TURBINES, SIMPLE CYCLE , ROLLS ROYCE, 8	CO OXIDATION CATALYST AND CLEAN BURNING FUELS	5	PPMVD@15%O2
NJ-0076	PSEG FOSSIL LLC KEARNY GENERATING STATION	12200-BOP100002	SIMPLE CYCLE TURBINE	Oxidation Catalyst, Good combustion practices	5	PPMVD@15% O2
NV-0033	EL DORADO ENERGY, LLC	A-00652	COMBUSTION TURBINE, COMBINED CYCLE & COGEN(2)	OXIDATION CATALYST	2.6	PPM @ 15% O2
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	AP4911-1504	TURBINE, COMBINED CYCLE COMBUSTION #2 WITH HRSG AND DUCT BURNER.	OXIDATION CATALYST SYSTEM	3.5	PPM @ 15% O2
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	AP4911-1504	TURBINE, COMBINED CYCLE COMBUSTION #1 WITH HRSG AND DUCT BURNER.	OXIDATION CATALYST	3.5	PPM @ 15% O2
NV-0036	TS POWER PLANT	AP4911-1349	35 MW COMBUSTION TURBINES	OXIDATION CATALYST	6	PPMVD
NV-0037	COPPER MOUNTAIN POWER	15347	LARGE COMBUSTION TURBINES, COMBINED CYCLE & COGENERATION	GOOD COMBUSTOR DESIGN AND AN OXIDATION CATALYST	3	PPMVD
NV-0038	IVANPAH ENERGY CENTER, L.P.	1616	LARGE COMBUSTION TURBINES, COMBINED CYCLE & COGENERATION	GOOD COMBUSTION CONTROL AND CATALYTIC OXIDATION	4	PPMVD
NV-0046	GOODSPRINGS COMPRESSOR STATION	468	LARGE COMBUSTION TURBINE - SIMPLE CYCLE	GOOD COMBUSTION PRACTICE	16	PPMVD
NV-0048	GOODSPRINGS COMPRESSOR STATION	468	SIMPLE-CYCLE SMALL COMBUSTION TURBINES (<25 MW)	GOOD COMBUSTION PRACTICES - THE TURBINE IS OPERATED WITHIN THE PARAMETERS ALLOWING THE PROCESS TO OPERATE AS EFFICIENTLY AS POSSIBLE.	16	PPMVD
NV-0050	MGM MIRAGE	825	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	LEAN PRE-MIX TECHNOLOGY AND OXIDATION CATALYST	0.0056	LB/MMBTU
NY-0095	CAITHNES BELLPORT ENERGY CENTER	PSD-NY-0001	COMBUSTION TURBINE	OXIDATION CATALYST	2	PPMVD@15%02
NY-0095	CAITHNES BELLPORT ENERGY CENTER	PSD-NY-0001	COMBUSTION TURBINE	OXIDATION CATALYST	2	PPMVD@15%02
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	07-00503	TURBINES (4) (MODEL GE 7FA), DUCT BURNERS ON		50.3	LB/H
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	07-00503	TURBINES (4) (MODEL GE 7FA), DUCT BURNERS OFF		25.7	LB/H

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
OH-0253	DAYTON POWER AND LIGHT COMPANY	08-04380	COMBUSTION TURBINE (1), SIMPLE CYCLE		301	LB/H
OH-0253	DAYTON POWER AND LIGHT COMPANY	08-04380	COMBUSTION TURBINES (2), SIMPLE CYCLE		1700	LB/H
OH-0253	DAYTON POWER AND LIGHT COMPANY	08-04380	COMBUSTION TURBINES (2), SIMPLE CYCLE		350	LB/H
OH-0253	DAYTON POWER AND LIGHT COMPANY	08-04380	COMBUSTION TURBINE (1), SIMPLE CYCLE		800	LB/H
OH-0291	OHIO EDISON CO.-WEST LORAIN PLANT	02-13376	SIMPLE CYCLE COMBUSTION TURBINES (5) W/ NATURAL GAS		83	LB/H
OH-0291	OHIO EDISON CO.-WEST LORAIN PLANT	02-13376	SIMPLE CYCLE COMBUSTION TURBINES (5) W/ DISTILLATE OIL		83	LB/H
OH-0304	ROLLING HILLS GENERATING PLANT	06-07747	NATURAL GAS FIRED TURBINES (5)	GOOD ENGINEERING PRACTICES	119	LB/H
OH-0333	DAYTON POWER & LIGHT ENERGY LLC	P0104867	Turbines (4), simple cycle, natural gas	efficient combution technology	301	LB/H
OH-0333	DAYTON POWER & LIGHT ENERGY LLC	P0104867	Turbines (4), simple cycle, fuel oil #2	efficient combustion technology	800	LB/H
OK-0104	HORSEHOE LAKE GENERATING STATION	97-137-C (M-3) PSD	TURBINE, SIMPLE CYCLE, (2)	GOOD COMBUSTION PRACTICES	62.5	PPMVD @15% O2
OK-0115	LAWTON ENERGY COGEN FACILITY	2001-205-C M-1 PSD	COMBUSTION TURBINE AND DUCT BURNER	GOOD COMBUSTION PRACTICES	16.38	PPMVD
OK-0117	PSO SOUTHWESTERN POWER PLT	2003-403-C PSD	GAS-FIRED TURBINES	COMBUSTION CONTROL	25	PPMVD
OK-0120	PSO RIVERSIDE JENKS POWER STA	2003-360-C M-1 PSD	COMBUSTION TURBINES	GOOD COMBUSTION PRACTICES & DESIGN	59	LB/H
OK-0127	WESTERN FARMERS ELECTRIC ANADARKO	2005-037-C(M-2) PSD	COMBUSTION TURBINE PEAKING UNIT(S)	NO CONTROLS FEASIBLE.	63	PPM
OR-0039	COB ENERGY FACILITY, LLC	18-0029	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, (4)	CATALYTIC OXIDATION	2	PPMVD @ 15% O2
OR-0041	WANAPA ENERGY CENTER	R10PSD-OR-05-01	COMBUSTION TURBINE & HEAT RECOVERY STEAM GENERATOR	OXIDATION CATALYST.	2	PPMDV @ 15% O2
OR-0043	UMATILLA GENERATING COMPANY, L.P.	30-0007	TURBINE, COMBINED CYCLE & DUCT BURNER, NAT GAS (2)	CATALYTIC OXIDATION	2	PPMVD @ 15% O2
PR-0008	PREPA	TV-4911-30-1196-0013	TURBINE, COMBINED CYCLE (2)		60	PPM @ 15% O2
RI-0023	RHODE ISLAND CENTRAL GENCO, LLC	RI-PSD-8	LANDFILL GAS-FIRED COMBUSTION TURBINE		100	PPMV
TX-0453	BAYPORT ENERGY CENTER	P1031	COMBUSTION TURBINE WITH 225 MMBTU/H DUCT BURNERS (2)	BACT WILL CONSIST OF PROPER COMBUSTION TECHNIQUES.	35.9	LB/H

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
TX-0454	EL PASO NATURAL GAS CORNUDAS COMPRESSOR STATION	P1030	TURBINES (2)		9.22	LB/H
TX-0469	TEXAS PETROCHEMICALS HOUSTON FACILITY	P999	TURBINE AND DUCT BURNER (3)	GOOD COMBUSTION AND SWEET NATURAL GAS	151.2	LB/H
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	PSD-TX-828M1	L-AREA GAS TURBINE		38.53	LB/H
TX-0497	INEOS CHOCOLATE BAYOU FACILITY	PSD-TX 983 AND 46192	COGENERATION TRAIN 2 AND 3 (TURBINE AND DUCT BURNER EMISSIONS)	BP AMOCO PROPOSES PROPER COMBUSTION CONTROL AS BACT FOR CO AND VOC EMISSIONS FROM THE TURBINES AND DUCT BURNERS. CO EMISSIONS FROM EACH TURBINE WILL NOT EXCEED 15 PPMVD AT 85% TO 100% OF BASE LOAD. CO EMISSIONS FROM EACH TU	66.81	LB/H
TX-0498	SIGNAL HILLS WICHITA FALLS POWER LP	PSD-TX 685 AND 16750	TURBINES (3)		32	LB/H
TX-0501	TEXSTAR GAS PROCESS FACILITY	PSD-TX 55M3 AND 6051	ALLISON 501KB GAS TURBINE GENERATOR		21.5	LB/H
TX-0502	NACOGDOCHES POWER STERNE GENERATING FACILITY	PSD-TX 1015 AND 49293	WESTINGHOUSE/SIEMENS MODEL SW501F GAS TURBINE W/ 416.5 MMBTU DUCT BURNERS	STEAG POWER LLC REPRESENTS GOOD COMBUSTION PRACTICES FOR THE CONTROL OF CO EMISSIONS FROM THE COMBUSTION TURBINES AND HRSG DUCT BURNERS. COMBINED CO WILL BE 20.2 PPMVD CORRECTED TO 15% O2.	109.4	LB/H
TX-0504	NAVASOTA POWER GENERATION FACILITY	PSD-TX 1059/1060 AND 76990	TURBINES WITH 165 MMBTU/HR DUCT BURNERS		68.6	LB/H
TX-0504	NAVASOTA POWER GENERATION FACILITY	PSD-TX 1059/1060 AND 76990	TURBINES WITHOUT 165 MMBTU/HR DUCT BURNERS		55.4	LB/H
TX-0504	NAVASOTA POWER GENERATION FACILITY	PSD-TX 1059/1060 AND 76990	STARTUP, SHUTDOWN, MAINTENANCE		1000	LB/H
TX-0506	NRG TEXAS ELECTRIC POWER GENERATION	PSD-TX 1051 AND 21587	TURBINE FIRING NATURAL GAS W/ BURNERS		496	LB/H
TX-0506	NRG TEXAS ELECTRIC POWER GENERATION	PSD-TX 1051 AND 21587	TURBINE FIRING NATURAL GAS W/O BURNERS		296	LB/H
TX-0506	NRG TEXAS ELECTRIC POWER GENERATION	PSD-TX 1051 AND 21587	TURBINE FIRING FUEL OIL W/ BURNERS		563	LB/H
TX-0506	NRG TEXAS ELECTRIC POWER GENERATION	PSD-TX 1051 AND 21587	TURBINE FIRING FUEL OIL W/O BURNERS		401	LB/H
TX-0506	NRG TEXAS ELECTRIC POWER GENERATION	PSD-TX 1051 AND 21587	ANNUAL LIMITS		830	LB/H
TX-0509	PONDEROSA PINE ENERGY PARTNERS COGENERATION FACILITY	PSD-TX-839	TURBINE AND 375 MMBTU/HR HEAT RECOVERY STEAM SYSTEM		348.5	LB/H
TX-0525	TEXAS GENCO UNITS 1 AND2	PSD-TX 807 AND 21587	80 MW GAS TURBINE		52	LB/H
TX-0525	TEXAS GENCO UNITS 1 AND2	PSD-TX 807 AND 21587	80 MW GAS TURBINE		93.5	LB/H
TX-0525	TEXAS GENCO UNITS 1 AND2	PSD-TX 807 AND 21587	80 MW GAS TURBINE		112.5	LB/H
TX-0525	TEXAS GENCO UNITS 1 AND2	PSD-TX 807 AND 21587	80 MW GAS TURBINE		71	LB/H

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
TX-0551	PANDA SHERMAN POWER STATION	PSDTX1198	Natural Gas-fired Turbines	Good combustion practices	4	PPMVD
TX-0552	WOLF HOLLOW POWER PLANT NO. 2	PSDTX1110	Natural gas-fired turbines	Good combustion practices	10	PPMVD
TX-0590	KING POWER STATION	PSDTX1125	Turbine	good combustion practices with an oxidation catalyst	2	PPMVD AT 15% O2
TX-0600	THOMAS C. FERGUSON POWER PLANT	PSDTX1244	Natural gas-fired turbines	Good combustion practices and oxidation catalyst	4	PPMVD
UT-0066	CURRANT CREEK	DAQE-2524002-04	NATURAL GAS FIRED TURBINES AND HEAT RECOVERY STEAM GENERATORS	OXIDATINO CATALYST FOR COMBINED CYCLE MODE OF OPERATION	3	PPMVD
VA-0287	JAMES CITY ENERGY PARK	61442	TURBINE, COMBINED CYCLE, NATURAL GAS,DUCT BURNER	GOOD COMBUSTION PRACTICES	12	PPM
VA-0287	JAMES CITY ENERGY PARK	61442	TURBINE, COMBINED CYCLE, NATURAL GAS	GOOD COMBUSTION PRACTICES	9	PPM
VA-0287	JAMES CITY ENERGY PARK	61442	TURBINE, COMBINED CYCLE, FUEL OIL	GOOD COMBUSTION PRACTICES	6	PPM
VA-0289	DUKE ENERGY WYTHE, LLC	11382	TURBINE, COMBINED CYCLE, NATURAL GAS	GOOD COMBUSTION PRACTICES.	9	PPMVD
VA-0289	DUKE ENERGY WYTHE, LLC	11382	TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	GOOD COMBUSTION PRACTICES	14.6	PPMVD
VA-0291	CPV WARREN LLC	81391	TURBINE, COMBINED CYCLE AND DUCT BURNER (2)	OXIDATION CATALYST, AND GOOD COMBUSTION PRACTICES.	1.8	PPMVD
VA-0291	CPV WARREN LLC	81391	TURBINE, COMBINED CYCLE (2)	OXIDATION CATALYST. GOOD COMBUSTION PRACTICES.	1.3	PPMVD
WA-0328	BP CHERRY POINT COGENERATION PROJECT	EFSEC/2002-01	GE 7FA COMBUSTION TURBINE & HEAT RECOVERY STEAM GENERATOR	LEAN PRE-MIX CT BURNER & OXIDATION CATALYST	2	PPMDV
WA-0334	SUMAS COMPRESSOR STATION	PSD-01-08 AMENDMENT 3	TURBINE, SIMPLE CYCLE	TWO OLDER 42 PPM NOX TURBINE ENGINES WERE REPLACED WITH 2 NEWER 25 PPM SOLONOX ENGINES. A THIRD TURBINE/COMPRESSOR WAS ALSO ADDED.	50	PPMDV
WI-0227	PORT WASHINGTON GENERATING STATION	04-RV-175	COMBINED CYCLE COMBUSTION TURBINES (4 W/ DUCT BURNER, HRSG)	NATURAL GAS, GOOD COMBUSTION PRACTICES, OXIDATION CATALYST	3	PPM@15% O2
WI-0240	WE ENERGIES CONCORD	05-SDD-320	COMBUSTION TURBINE, 100 MW, NATURAL GAS		20	LB/H
WY-0066	MEDICINE BOW IGL PLANT	CT-5873	COMBUSTION TURBINE 1	OXIDATION CATALYST	6	PPM @ 15% O2
WY-0066	MEDICINE BOW IGL PLANT	CT-5873	COMBUSTION TURBINE 2	OXIDATION CATALYST	6	PPM @ 15% O2
WY-0066	MEDICINE BOW IGL PLANT	CT-5873	COMBUSTION TURBINE 3	OXIDATION CATALYST	6	PPM @ 15% O2
WY-0067	ECHO SPRINGS GAS PLANT	MD-7837	TURBINES S35-S36	GOOD COMBUSTION PRACTICES	25	PPMV

RBLCID	FACILITY_NAME	PERMIT_NUM	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
WY-0067	ECHO SPRINGS GAS PLANT	MD-7837	TURBINE S34	GOOD COMBUSTION PRACTICES	50	PPMV
WY-0067	ECHO SPRINGS GAS PLANT	MD-7837	TURBINE S37	GOOD COMBUSTION PRACTICES	25	PPMV

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
KS-0028	NEARMAN CREEK POWER STATION	COMBUSTION TURBINE #4 FACILITY	GOOD COMBUSTION PRACTICES / DESIGN	10	LB/H
MD-0031	CHALK POINT	GE 7EA COMBUSTION TURBINE - NG, SC ONLY	USE OF LOW SULFUR FUELS	5	LB/H
CO-0064	RAWHIDE ENERGY STATION	UNIT F COMBUSTION TURBINE	USE OF PIPELINE QUALITY NATURAL GAS.	18	LB/H
FL-0261	ARVAH B. HOPKINS GENERATING STATION	TURBINE, SIMPLE CYCLE, NATURAL GAS, (2)	CLEAN FUELS	2.45	LB/H
FL-0279	TEC/POLK POWER ENERGY STATION	SIMPLE CYCLE GAS TURBINE	FIRING OF NATURAL GAS GOOD COMBUSTION PRACTICES	10	% OPACITY
FL-0287	OLEANDER POWER PROJECT	SIMPLE CYCLE COMBUSTION TURBINE	CLEAN FUELS	1.5	GR S/100 SCF
FL-0300	JACKSONVILLE ELECTRIC AUTHORITY/JEA	SIMPLE CYCLE TURBINE 172 MW	NATURAL GAS AS PRIMARY FUEL WITH 0.05% SULFUR DISTILLATE FUEL OIL AS BACKUP. USE WATER INJECTION WHEN FIRING OIL	0	
FL-0305	OUC CURTIS H. STANTON ENERGY CENTER	300 MW COMBINED CYCLE COMBUSTION TURBINE	NATURAL GAS AN ULTRA LOW SULFUR FUEL OIL	2	GR S/100 DSCF OF GAS
FL-0310	SHADY HILLS GENERATING STATION	TWO SIMPLE CYCLE COMBUSTION TURBINE - MODEL 7FA		10	% OPACITY
FL-0319	GREENLAND ENERGY CENTER	190 MW Combustion Turbine	Use of low ash, low sulfur fuels,	10	OPACITY
GA-0139	DAHLBERG COMBUSDTION TURBINE ELECTRIC GENERATING FACILITY (P	SIMPLE CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	GOOD COMBUSTION PRACTICES PIPELINE QUALITY NATURAL GAS, ULTRA LOW SULFUR DISTILLATE FUEL	9.1	LB/H
LA-0191	MICHOUD ELECTRIC GENERATING PLANT	COMBUSTION GAS TURBINES 4 & 5 (SIMPLE CYCLE)	USE OF CLEAN BURNING FUELS (NATURAL GAS)	7.85	LB/H
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	GAS TURBINE GENERATOR NOS. 1-4	DRY LOW EMISSIONS (DLE) COMBUSTION TECHNOLOGY WITH LEAN PREMIX OF AIR AND FUEL	2.11	LB/H
LA-0257	SABINE PASS LNG TERMINAL	Simple Cycle Refrigeration Compressor Turbines (16)	Good combustion practices and fueled by natural gas	2.08	LB/H
LA-0257	SABINE PASS LNG TERMINAL	Simple Cycle Generation Turbines (2)	Good combustion practices and fueled by natural gas	2.08	LB/H
LA-0258	CALCASIEU PLANT	TURBINE EXHAUST STACK NO. 1 & NO. 2	USE OF PIPELINE NATURAL GAS	17	LB/H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
LA-0258	CALCASIEU PLANT	TURBINE EXHAUST STACK NO. 1 & NO. 2	USE OF PIPELINE NATURAL GAS	17	LB/H
MD-0032	DICKERSON	UNIT 4 -GE FRAME 7F COM. TURBINES W/ HRSG - NG SC		21	LB/H
MD-0032	DICKERSON	UNIT 5 -GE FRAME 7F COM. TURBINES W/ HRSG - NG SC		9	LB/H
MD-0040	CPV ST CHARLES	COMBUSTION TURBINES (2)		0.012	LB/MMBTU @ 15% O2
MD-0040	CPV ST CHARLES	COMBUSTION TURBINES (2)		0.012	LB/MMBTU @ 15% O2
MD-0040	CPV ST CHARLES	COMBUSTION TURBINES (2)		0.012	LB/MMBTU @ 15% O2
MI-0327	INDECK-NILES, LLC	4 GAS TURBINES WITH HEAT RECOVERY STEAM GENERATORS	USE OF NATURAL GAS.	8.5	LB/H
MN-0053	FAIRBAULT ENERGY PARK	TURBINE, SIMPLE CYCLE, NATURAL GAS (1)	CLEAN FUEL AND GOOD COMBUSTION PRACTICES.	0.01	LB/MMBTU
MN-0075	GREAT RIVER ENERGY - ELK RIVER STATION	COMBUSTION TURBINE GENERATOR	FUEL LIMITED TO NATURAL GAS AND ULTRA-LOW SULFUR FUEL OIL	0	
MN-0075	GREAT RIVER ENERGY - ELK RIVER STATION	COMBUSTION TURBINE GENERATOR	FUEL LIMITED TO NATURAL GAS AND ULTRA-LOW SULFUR FUEL OIL	0	
MN-0075	GREAT RIVER ENERGY - ELK RIVER STATION	COMBUSTION TURBINE GENERATOR	FUEL LIMITED TO NATURAL GAS AND ULTRA-LOW SULFUR FUEL OIL	0	
MO-0067	SOUTH HARPER PEAKING FACILITY	TURBINES, SIMPLE CYCLE, NATURAL GAS, (3)	GOOD COMBUSTION PRACTICES	15.25	LB/H
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	EMISSION POINT AA-001		7.35	LB/H
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	EMISSION POINT AA-002		7.35	LB/H
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	EMISSION POINT AA-003		7.35	LB/H
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	EMISSION POINT AA-004		7.35	LB/H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
MS-0074	MOSELLE PLANT	COMBUSTION TURBINE, GAS-FIRED, SIMPLE-CYCLE		10	LB/H
NE-0021	CASS COUNTY POWER PLANT	2-173 MW COMBUSTION TURBINES		0.12	LB/MMBTU
NE-0022	C. W. BURDICK GENERATING STATION	GAS-FIRED COMBUSTION TURBINE	LOW ASH CONTENT NG	10	LB/H
NJ-0075	BAYONNE ENERGY CENTER	COMBUSTION TURBINES, SIMPLE CYCLE , ROLLS ROYCE, 8	BURNING CLEAN FUELS, NATURAL GAS AND ULTRA LOW SULFUR DISTILLATE OIL WITH SULFUR CONTENT OF 15 PPM.	5	LB/H
NJ-0075	BAYONNE ENERGY CENTER	COMBUSTION TURBINES, SIMPLE CYCLE , ROLLS ROYCE, 8	BURNING CLEAN FUELS, NATURAL GAS AND ULTRA LOW SULFUR DISTILLATE OIL WITH SULFUR CONTENT OF 15 PPM.	5	LB/H
NJ-0076	PSEG FOSSIL LLC KEARNY GENERATING STATION	SIMPLE CYCLE TURBINE	Good combustion practice, Use of Clean Burning Fuel: Natural gas	6	LB/H
NJ-0076	PSEG FOSSIL LLC KEARNY GENERATING STATION	SIMPLE CYCLE TURBINE	Good combustion practice, Use of Clean Burning Fuel: Natural gas	6	LB/H
NJ-0076	PSEG FOSSIL LLC KEARNY GENERATING STATION	SIMPLE CYCLE TURBINE	Good combustion practice, Use of Clean Burning Fuel: Natural gas	6	LB/H
NV-0046	GOODSPRINGS COMPRESSOR STATION	LARGE COMBUSTION TURBINE - SIMPLE CYCLE	NATURAL GAS IS THE ONLY FUEL FOR THE PROCESS.	0.0066	LB/MMBTU
NY-0093	TRIGEN-NASSAU ENERGY CORPORATION	TURBINE, COMBINED CYCLE		4.66	LB/H
NY-0093	TRIGEN-NASSAU ENERGY CORPORATION	TURBINE, COMBINED CYCLE, DUCT BURNER		8.42	LB/H
OH-0253	DAYTON POWER AND LIGHT COMPANY	COMBUSTION TURBINE (1), SIMPLE CYCLE		8	LB/H
OH-0253	DAYTON POWER AND LIGHT COMPANY	COMBUSTION TURBINES (2), SIMPLE CYCLE		8	LB/H
OH-0291	OHIO EDISON CO.-WEST LORAIN PLANT	SIMPLE CYCLE COMBUSTION TURBINES (5) W/ NATURAL GAS		5	LB/H
OH-0304	ROLLING HILLS GENERATING PLANT	NATURAL GAS FIRED TURBINES (5)		17.3	LB/H
OH-0304	ROLLING HILLS GENERATING PLANT	NATURAL GAS FIRED TURBINES (5)		17.3	LB/H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
OH-0333	DAYTON POWER & LIGHT ENERGY LLC	Turbines (4), simple cycle, natural gas		0.013	LB/MMBTU
OH-0333	DAYTON POWER & LIGHT ENERGY LLC	Turbines (4), simple cycle, natural gas		0.013	LB/MMBTU
OK-0120	PSO RIVERSIDE JENKS POWER STA	COMBUSTION TURBINES	GOOD COMBUSTION PRACTICES IN COMBINATION WITH THE USE OF LOW-ASH FUEL	10	LB/H
OK-0127	WESTERN FARMERS ELECTRIC ANADARKO	COMBUSTION TURBINE PEAKING UNIT(S)	NO CONTROLS FEASIBLE.	4	LB/H
OR-0043	UMATILLA GENERATING COMPANY, L.P.	TURBINE, COMBINED CYCLE & DUCT BURNER, NAT GAS (2)	GOOD COMBUSTION AND FIRING NATURAL GAS	0.1	GR/DSCF
OR-0043	UMATILLA GENERATING COMPANY, L.P.	TURBINE, COMBINED CYCLE & DUCT BURNER, NAT GAS (2)	GOOD COMBUSTION AND FIRING NATURAL GAS	0.0042	LB/MMBTU
TX-0469	TEXAS PETROCHEMICALS HOUSTON FACILITY	TURBINE AND DUCT BURNER (3)	GOOD COMBUSTION AND SWEET NATURAL GAS	14.78	LB/H
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	L-AREA GAS TURBINE		2.09	LB/H
TX-0504	NAVASOTA POWER GENERATION FACILITY	TURBINES WITH 165 MMBTU/HR DUCT BURNERS	USE OF NATURAL GAS	12.4	LB/H
TX-0504	NAVASOTA POWER GENERATION FACILITY	TURBINES WITHOUT 165 MMBTU/HR DUCT BURNERS		10.4	LB/H
TX-0504	NAVASOTA POWER GENERATION FACILITY	STARTUP, SHUTDOWN, MAINTENANCE		10.5	LB/H
TX-0506	NRG TEXAS ELECTRIC POWER GENERATION	TURBINE FIRING NATURAL GAS W/ BURNERS		11.5	LB/H
TX-0506	NRG TEXAS ELECTRIC POWER GENERATION	TURBINE FIRING NATURAL GAS W/O BURNERS		7	LB/H
TX-0509	PONDEROSA PINE ENERGY PARTNERS COGENERATION FACILITY	TURBINE AND 375 MMBTU/HR HEAT RECOVERY STEAM SYSTEM		57.8	LB/H
TX-0509	PONDEROSA PINE ENERGY PARTNERS COGENERATION FACILITY	TURBINE AND 375 MMBTU/HR HEAT RECOVERY STEAM SYSTEM		57	LB/H
TX-0525	TEXAS GENCO UNITS 1 AND2	80 MW GAS TURBINE		7	LB/H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
TX-0525	TEXAS GENCO UNITS 1 AND2	80 MW GAS TURBINE		11.5	LB/H
WI-0240	WE ENERGIES CONCORD	COMBUSTION TURBINE, 100 MW, NATURAL GAS		39	LB/H
TX-0506	NRG TEXAS ELECTRIC POWER GENERATION	TURBINE FIRING FUEL OIL W/ BURNERS		19.5	LB/H
WY-0066	MEDICINE BOW IGL PLANT	COMBUSTION TURBINE 1	GOOD COMBUSTION PRACTICES	10	LB/H
WY-0066	MEDICINE BOW IGL PLANT	COMBUSTION TURBINE 2	GOOD COMBUSTION PRACTICES	10	LB/H
WY-0066	MEDICINE BOW IGL PLANT	COMBUSTION TURBINE 3	GOOD COMBUSTION PRACTICES	10	LB/H
FL-0261	ARVAH B. HOPKINS GENERATING STATION	TURBINE, SIMPLE CYCLE (2) FUEL OIL	CLEAN FUEL	14.94	LB/H
MA-0035	THOMAS H. WATSON GENERATING STATION	SIMPLE-CYCLE GAS TURBINE		0.02	LB/MMBTU
MD-0031	CHALK POINT	GE 7EA COMBUSTION TURBINE - FO, SC ONLY	USE OF LOW SULFUR FUELS	10	LB/H
MD-0032	DICKERSON	UNIT 5 -GE FRAME 7F COMB. TURBINES W/ HRSG- FO SC		17	LB/H
MD-0032	DICKERSON	UNIT 4 -GE FRAME 7F COMB. TURBINES W/ HRSG- FO SC		22	LB/H
MN-0053	FAIRBAULT ENERGY PARK	TURBINE, SIMPLE CYCLE, DISTILLATE OIL (1)	CLEAN FUEL AND GOOD COMBUSTION PRACTICES.	0.03	LB/MMBTU
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	GENERAL ELECTRIC COMBUSTION TURBINES		15.8	LB/H
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	GENERAL ELECTRIC COMBUSTION TURBINES		15.8	LB/H
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	GENERAL ELECTRIC COMBUSTION TURBINES		15.8	LB/H
MS-0072	TVA - KEMPER COMBUSTION TURBINE PLANT	GENERAL ELECTRIC COMBUSTION TURBINES		15.8	LB/H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
NV-0036	TS POWER PLANT	35 MW COMBUSTION TURBINES	LOW ASH FUEL	13.7	LB/H
NY-0093	TRIGEN-NASSAU ENERGY CORPORATION	TURBINE, COMBINED CYCLE, FUEL OIL	LOW SULFUR FUEL (0.05% S)	13.75	LB/H
OH-0253	DAYTON POWER AND LIGHT COMPANY	COMBUSTION TURBINES (2), SIMPLE CYCLE		15	LB/H
OH-0253	DAYTON POWER AND LIGHT COMPANY	COMBUSTION TURBINE (1), SIMPLE CYCLE		15	LB/H
OH-0291	OHIO EDISON CO.-WEST LORAIN PLANT	SIMPLE CYCLE COMBUSTION TURBINES (5) W/ DISTILLATE OIL		10	LB/H
OH-0333	DAYTON POWER & LIGHT ENERGY LLC	Turbines (4), simple cycle, fuel oil #2		0.026	LB/MMBTU
OH-0333	DAYTON POWER & LIGHT ENERGY LLC	Turbines (4), simple cycle, fuel oil #2		0.026	LB/MMBTU
TX-0506	NRG TEXAS ELECTRIC POWER GENERATION	TURBINE FIRING FUEL OIL W/O BURNERS		15	LB/H
TX-0525	TEXAS GENCO UNITS 1 AND2	80 MW GAS TURBINE		19.5	LB/H
FL-0280	TREASURE COAST ENERGY CENTER	COMBINED CYCLE COMBUSTION TURBINE	FUEL SPECIFICATIONS	2	GRAINS S/100 SCF
NJ-0066	AES RED OAK LLC	COMBINED CYCLE NATURAL GAS FIRED COMBUSTION TURBINES(3)	THE USE OF ONLY NATURAL GAS, A CLEAN BURNING FUEL IS CONSIDERED BACT.	29.43	LB/H
NJ-0074	WEST DEPTFORD ENERGY	TURBINE, COMBINED CYCLE	CLEAN FUELS - NATURAL GAS AND ULTRA LOW SULFUR (15PPM SULFUR) DISTILLATE OIL	18.66	LB/H
NJ-0074	WEST DEPTFORD ENERGY	TURBINE, COMBINED CYCLE	USE OF CLEAN FUELS, NATURAL GAS AND ULTRA LOW SULFUR DISTILLATE OIL	18.66	LB/H
AK-0071	INTERNATIONAL STATION POWER PLANT	GE LM6000PF-25 Turbines (4)	Good Combustion Practices	0.0066	LB/MMBTU
AK-0071	INTERNATIONAL STATION POWER PLANT	GE LM6000PF-25 Turbines (4)	Good Combustion Practices	0.0066	LB/MMBTU
AK-0071	INTERNATIONAL STATION POWER PLANT	GE LM6000PF-25 Turbines (4)	Good Combustion Practices	0.0066	LB/MMBTU

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	TURBINE, COMBINED CYCLE & DUCT BURNER		25	LB/H
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	TURBINE, COMBINED CYCLE		18	LB/H
AZ-0047	WELLTON MOHAWK GENERATING STATION	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - SW501F TURBINES OPTION		33.1	LB/H
AZ-0047	WELLTON MOHAWK GENERATING STATION	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - GE7FA TURBINES OPTION		29.8	LB/H
CA-1143	SUTTER POWER PLANT	2 COMBUSTION TURBINES		11.5	LB/H
CA-1144	BLYTHE ENERGY PROJECT II	2 COMBUSTION TURBINES	NATURAL GAS W/ SULFUR CONTENT LESS THAN OR EQUAL TO 0.5 GRAINS PER 100 SCF	6	LB/H
CO-0056	ROCKY MOUNTAIN ENERGY CENTER, LLC	NATURAL-GAS FIRED, COMBINED-CYCLE TURBINE	NATURAL GAS QUALITY FUEL ONLY AND GOOD COMBUSTION CONTROL PRACTICES.	0.0074	LB/MMBTU
CT-0151	KLEEN ENERGY SYSTEMS, LLC	SIEMENS SGT6-5000F COMBUSTION TURBINE #1 AND #2 (NATURAL GAS FIRED) WITH 445 MMBTU/HR NATURAL GAS DUCT BURNER		11	LB/H
FL-0265	HINES POWER BLOCK 4	COMBINED CYCLE TURBINE	CLEAN FUELS	10	% OPACITY
FL-0286	FPL WEST COUNTY ENERGY CENTER	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS		2	GS/100 SCF GAS
FL-0304	CANE ISLAND POWER PARK	300 MW COMBINED CYCLE COMBUSTION TURBINE	FUEL SPECIFICATIONS : 2 GR S/100 SCF OF GAS	2	GR S/100 SCF GAS
ID-0018	LANGLEY GULCH POWER PLANT	COMBUSTION TURBINE, COMBINED CYCLE W/ DUCT BURNER	GOOD COMBUSTION PRACTICES (GCP)	0	
LA-0136	PLAQUEMINE COGENERATION FACILITY	(4) GAS TURBINES/DUCT BURNERS	USE OF CLEAN BURNING FUELS	33.5	LB/H
LA-0191	MICHOUD ELECTRIC GENERATING PLANT	COMBUSTION GAS TURBINES 4 & 5 (COMBINED CYCLE)	USE OF CLEAN BURNING FUELS (NATURAL GAS)	7.85	LB/H*
LA-0192	CRESCENT CITY POWER	GAS TURBINES - 187 MW (2)	USE OF CLEAN BURNING FUEL AND GOOD COMBUSTION PRACTICES	29.4	LB/H
LA-0194	SABINE PASS LNG TERMINAL	30 MW GAS TURBINE GENERATORS (4)	GOOD COMBUSTION PRACTICES AND THE USE OF NATURAL GAS AS FUEL	2.11	LB/H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B)	WHILE FIRING NATURAL GAS: USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES WHILE FIRING FUEL OIL: USE OF ULTRA LOW SULFUR FUEL OIL AND GOOD	26.23	LB/H
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B)	WHILE FIRING NATURAL GAS: USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES WHILE FIRING FUEL OIL: USE OF ULTRA LOW SULFUR FUEL OIL AND GOOD	26.23	LB/H
LA-0257	SABINE PASS LNG TERMINAL	Combined Cycle Refrigeration Compressor Turbines (8)	Good combustion practices and fueled by natural gas	2.08	LB/H
MD-0032	DICKERSON	UNIT 4 -GE FRAME 7F COMB. TURBINES W/ HRSG - NG CC		26	LB/H
MD-0032	DICKERSON	UNIT 5 -GE FRAME 7F COMB. TURBINES W/ HRSG - NG CC		15	LB/H
MI-0366	BERRIEN ENERGY, LLC	3 COMBUSTION TURBINES AND DUCT BURNERS	STATE OF THE ART COMBUSTION TECHNIQUES AND USE OF NATURAL GAS ARE BACT FOR PM10.	19	LB/H
MN-0053	FAIRBAULT ENERGY PARK	TURBINE, COMBINED CYCLE, NATURAL GAS (1)	CLEAN FUEL AND GOOD COMBUSTION PRACTICES.	0.01	LB/MMBTU
MN-0054	MANKATO ENERGY CENTER	COMBUSTION TURBINE, LARGE 2 EACH	CLEAN FUELS AND GOOD COMBUSTION	0.057	LB/MMBTU
MN-0054	MANKATO ENERGY CENTER	COMBUSTION TURBINE, LARGE, 2 EACH	CLEAN FUELS AND GOOD COMBUSTION PRACTICES	0.009	LB/MMBTU
MN-0054	MANKATO ENERGY CENTER	COMBUSTION TURBINE, LARGE 2 EACH	CLEAN FUELS AND GOOD COMBUSTION	0.057	LB/MMBTU
MN-0054	MANKATO ENERGY CENTER	COMBUSTION TURBINE, LARGE, 2 EACH	CLEAN FUELS AND GOOD COMBUSTION PRACTICES	0.009	LB/MMBTU
MN-0071	FAIRBAULT ENERGY PARK	COMBINED CYCLE COMBUSTION TURBINE W/DUCT BURNER		0.01	LB/MMBTU
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, LLC	EMISSION POINT AA-001 GEN. ELEC. COMBUST. TURBINE		20.59	LB/H
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, LLC	EMISSION POINT AA-002 GEN ELEC. COMB. TURBINE		20.59	LB/H
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, LLC	EMISSION POINT AA-003 GEN. ELEC COMB TURBINES		20.59	LB/H
NC-0101	FORSYTH ENERGY PLANT	TURBINE, COMBINED CYCLE, NATURAL GAS, (3)	USE OF ONLY CLEAN-BURNING LOW-SULFUR FUELS AND GOOD COMBUSTION PRACTICES.	0.019	LB/MMBTU

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
NC-0101	FORSYTH ENERGY PLANT	TURBINE & DUCT BURNER, COMBINED CYCLE, NAT GAS, 3	CLEAN BURNING LOW-SULFUR FUELS AND GOOD COMBUSTION PRACTICES	0.021	LB/MMBTU
NV-0033	EL DORADO ENERGY, LLC	COMBUSTION TURBINE, COMBINED CYCLE & COGEN(2)		9	LB/H
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	TURBINE, COMBINED CYCLE COMBUSTION #2 WITH HRSG AND DUCT BURNER.	BEST COMBUSTION PRACTICES.	0.011	LB/MMBTU
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	TURBINE, COMBINED CYCLE COMBUSTION #1 WITH HRSG AND DUCT BURNER.	BEST COMBUSTION PRACTICES.	0.011	LB/MMBTU
NV-0037	COPPER MOUNTAIN POWER	LARGE COMBUSTION TURBINES, COMBINED CYCLE & COGENERATION	USE OF LOW-SULFUR NATURAL GAS	21.3	LB/H
NV-0038	IVANPAH ENERGY CENTER, L.P.	LARGE COMBUSTION TURBINES, COMBINED CYCLE & COGENERATION	GOOD COMBUSTION CONTROL AND USE OF PIPELINE-QUALITY NATURAL GAS	11.25	LB/H
NY-0095	CAITHNES BELLPORT ENERGY CENTER	COMBUSTION TURBINE	LOW SULFUR FUEL	0.0055	LB/MMBTU
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	TURBINES (4) (MODEL GE 7FA), DUCT BURNERS ON		23.3	LB/H
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	TURBINES (4) (MODEL GE 7FA), DUCT BURNERS OFF		15	LB/H
OK-0115	LAWTON ENERGY COGEN FACILITY	COMBUSTION TURBINE AND DUCT BURNER	GOOD COMBUSTION PRACTICES	0.0067	LB/MMBTU
OK-0117	PSO SOUTHWESTERN POWER PLT	GAS-FIRED TURBINES	USE OF LOW ASH FUEL (NATURAL GAS) AND EFFICIENT COMBUSTION	0.0093	LB/MMBTU
OR-0039	COB ENERGY FACILITY, LLC	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, (4)	GOOD COMBUSTION AND FIRING NATURAL GAS	14	LB/H
OR-0041	WANAPA ENERGY CENTER	COMBUSTION TURBINE & HEAT RECOVERY STEAM GENERATOR		0	
TX-0497	INEOS CHOCOLATE BAYOU FACILITY	COGENERATION TRAIN 2 AND 3 (TURBINE AND DUCT BURNER EMISSIONS)	BACT FOR PARTICULATE MATTER FROM THE GAS FIRED TURBINES AND DUCT BURNERS.	10.03	LB/H
TX-0502	NACOGDOCHES POWER STERNE GENERATING FACILITY	WESTINGHOUSE/SIEMENS MODEL SW501F GAS TURBINE W/ 416.5 MMBTU DUCT BURNERS	FIRING OF PIPELINE NATURAL GAS IN THE COMBUSTION TURBINES AND DUCT FIRED HRSGS AS BACT FOR PM10.	26.9	LB/H
TX-0590	KING POWER STATION	Turbine	use of low ash fuel (natural gas or low sulfur diesel as a backup)	11.1	LB/H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
TX-0590	KING POWER STATION	Turbine	use of low ash fuel (natural gas or low sulfur diesel as a backup)	11.1	LB/H
TX-0590	KING POWER STATION	Turbine	use low ash fuel (natural gas or low sulfur diesel as a backup) and good combustion practices	11.1	LB/H
TX-0600	THOMAS C. FERGUSON POWER PLANT	Natural gas-fired turbines	pipeline quality natural gas	33.43	LB/H
UT-0066	CURRANT CREEK	NATURAL GAS FIRED TURBINES AND HEAT RECOVERY STEAM GENERATORS		0.066	LB/MMBTU
VA-0287	JAMES CITY ENERGY PARK	TURBINE, COMBINED CYCLE, NATURAL GAS,DUCT BURNER	GOOD COMBUSTION/DESIGN AND CLEAN FUEL	24.7	LB/H
VA-0287	JAMES CITY ENERGY PARK	TURBINE, COMBINED CYCLE, NATURAL GAS	GOOD COMBUSTION/DESIGN AND CLEAN FUEL	18	LB/H
VA-0287	JAMES CITY ENERGY PARK	TURBINE, COMBINED CYCLE, NATURAL GAS,DUCT BURNER	GOOD COMBUSTION/DESIGN AND CLEAN FUEL	24.7	LB/H
VA-0287	JAMES CITY ENERGY PARK	TURBINE, COMBINED CYCLE, NATURAL GAS	GOOD COMBUSTION PRACTICES/DESIGN AND CLEAN FUEL	18	LB/H
VA-0289	DUKE ENERGY WYTHE, LLC	TURBINE, COMBINED CYCLE, NATURAL GAS	GOOD COMBUSTION PRACTICES.	17.5	LB/H
VA-0289	DUKE ENERGY WYTHE, LLC	TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	GOOD COMBUSTION PRACTICES	23.7	LB/H
VA-0291	CPV WARREN LLC	TURBINE, COMBINED CYCLE (2)	CLEAN BURNING FUEL NATURAL GAS ONLY. GOOD COMBUSTION PRACTICES. FUEL HAS MAXIMUM .002% BY WEIGHT SULFUR CONTENT	0.013	LB/MMBTU
WA-0328	BP CHERRY POINT COGENERATION PROJECT	GE 7FA COMBUSTION TURBINE & HEAT RECOVERY STEAM GENERATOR	LIMIT FUEL TYPE TO NATURAL GAS	0	
TX-0453	BAYPORT ENERGY CENTER	COMBUSTION TURBINE WITH 225 MMBTU/H DUCT BURNERS (2)	BACT WILL CONSIST OF PROPER COMBUSTION TECHNIQUES.	14.7	LB/H
AR-0105	AECI - DELL	COMBUSTION TURBINE #1 (SN-01) NO. 2 FUEL OIL SERVICE	GOOD COMBUSTION	48.9	LB/H
AR-0105	AECI - DELL	COMBUSTION TURBINE #2 (SN-02) NO. 2 FUEL OIL	GOOD COMBUSTION PRACTICES AND FUEL MONITORING	48.9	LB/H
CT-0151	KLEEN ENERGY SYSTEMS, LLC	SIEMENS SGT6-5000F COMBUSTION TURBINE #1 AND #2 (OIL FIRED) WITH 445 MMBTU/HR NATURAL GAS DUCT BURNER		57	LB/H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
MD-0032	DICKERSON	UNIT 4 -GE FRAME 7F COMB. TURBINES W/ HRSG- FO CC		41	LB/H
MD-0032	DICKERSON	UNIT 5 -GE FRAME 7F COMB. TURBINES W/ HRSG- FO CC		39	LB/H
MN-0053	FAIRBAULT ENERGY PARK	TURBINE, COMBINED CYCLE, DISTILLATE OIL (1)	CLEAN FUEL AND GOOD COMBUSTION PRACTICES.	0.03	LB/MMBTU
NC-0101	FORSYTH ENERGY PLANT	TURBINE, COMBINED CYCLE, FUEL OIL, (3)	USE OF ONLY CLEAN-BURNING, LOW- SULFUR FUELS AND GOOD COMBUSTION PRACTICES.	0.0358	LB/MMBTU
NC-0101	FORSYTH ENERGY PLANT	TURBINE & DUCT BURNER, COMBINED CYCLE, FUEL OIL, 3	CLEAN-BURNING, LOW SULFUR FUELS (< 0.015% S), GOOD COMBUSTION PRACTICES.	0.0248	LB/MMBTU
NY-0095	CAITHNES BELLPORT ENERGY CENTER	COMBUSTION TURBINE	LOW SULFUR FUEL (0.04%).	0.051	LB/MMBTU
TX-0525	TEXAS GENCO UNITS 1 AND2	80 MW GAS TURBINE		15	LB/H
VA-0287	JAMES CITY ENERGY PARK	TURBINE, COMBINED CYCLE, FUEL OIL	GOOD COMBUSTION/DESIGN AND CLEAN FUEL	43.9	LB/H
VA-0287	JAMES CITY ENERGY PARK	TURBINE, COMBINED CYCLE, FUEL OIL	GOOD COMBUSTION/DESIGN	43.9	LB/H
TX-0506	NRG TEXAS ELECTRIC POWER GENERATION	ANNUAL LIMITS		50.9	T/YR
AK-0062	BADAMI DEVELOPMENT FACILITY	SOLAR MARS 90 TURBINE	GOOD OPERATION PRACTICES	10	% OPACITY
AL-0251	HILLABEE ENERGY CENTER	COMBUSTION TURBINE	GOOD COMBUSTION PRACTICES	27.5	LB/H
FL-0266	PAYNE CREEK GENERATING STATION/SEMINOLE ELECTRIC	SIMPLE CYCLE COMBUSTION TURBINES	CLEAN FUELS	10	% OPACITY
MD-0035	DOMINION	COMBUSTION TURBINE		0.0066	LB/MMBTU
MD-0036	DOMINION	COMBUSTION TURBINE	USE OF LNG QUALITY, LOW SULFUR NATURAL GAS	0.0066	LB/MMBTU
NV-0048	GOODSPRINGS COMPRESSOR STATION	SIMPLE-CYCLE SMALL COMBUSTION TURBINES (<25 MW)	PROPER OPERATION OF THE TURBINE	0.0066	LB/MMBTU

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
NV-0050	MGM MIRAGE	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	GOOD COMBUSTION PRACTICES AND LIMITING THE FUEL TO NATURAL GAS ONLY	0.202	LB/MMBTU
TX-0454	EL PASO NATURAL GAS CORNUDAS COMPRESSOR STATION	TURBINES (2)		0.55	LB/H
NH-0014	UNIVERSITY OF NEW HAMPSHIRE	LANDFILL GAS/ NAT GAS COMBUSTION TURBINE	GOOD COMBUSTION PRACTICES AND FILTERING OF LFG THROUGH CARBON FILTER	0.042	G/B-HP-H
MA-0037	CENTRAL HEATING PLANT: AMHERST CAMPUS	COMBUSTION TURBINE		0.03	LB/MMBTU
*SD-0005	DEER CREEK STATION	Combustion turbine/heat recovery steam generator	Good Combustion	23.2	POUNDS PER HOUR
NY-0101	CORNELL COMBINED HEAT & POWER PROJECT	COMBUSTION TURBINES 2	SULFUR IN GAS ASSUMED MAX. 1.2 GR/100 SCF; WORK PRACTICE TO MINIMIZE NH3 SLIP.	3.9	LB/H
NY-0101	CORNELL COMBINED HEAT & POWER PROJECT	COMBUSTION TURBINES 3	ULTRA LOW SULFUR DIESEL AT 15 PPM; WORK PRACTICE TO MINIMIZE NH3 SLIP.	6.3	LB/H
NY-0101	CORNELL COMBINED HEAT & POWER PROJECT	COMBUSTION TURBINES 1	SULFUR IN GAS ASSIGNED MAX 1.2 GR/100 SCF; WORK PRACTICE TO MINIMIZE NHZ SLIP.	6.5	LB/H
NY-0101	CORNELL COMBINED HEAT & POWER PROJECT	COMBUSTION TURBINES 2	SULFUR IN GAS ASSUMED MAX 1.2 GR/100 SCF;WORK PRACTICE TO MINIMIZE NH3 SLIP.	4.1	LB/H
NY-0101	CORNELL COMBINED HEAT & POWER PROJECT	COMBUSTION TURBINES 3	ULTRA LOW SULFUR DIESEL AT 15 PPM; WORK PRACTICE TO MINIMIZE NH3 SLIP.	6.3	LB/H
NY-0101	CORNELL COMBINED HEAT & POWER PROJECT	COMBUSTION TURBINES 1	SULFUR IN GAS ASSIGNED MAX 1.2 GR/100 SCF; WORK PRACTICE TO MINIMIZE NHZ SLIP	6.7	LB/H
NY-0101	CORNELL COMBINED HEAT & POWER PROJECT	COMBUSTION TURBINES 2	SULFUR IN GAS ASSUMED MAX 1.2 GR/100 SCF; WORK PRACTICE TO MINIMIZE NH3 SLIP.	3.9	LB/H
NY-0101	CORNELL COMBINED HEAT & POWER PROJECT	COMBUSTION TURBINES 3	ULTRA LOW SULFUR DIESEL AT 15 PPM, WORK PRACTICE TO MINIMIZE NH3 SLIP.	6.3	LB/H
NY-0101	CORNELL COMBINED HEAT & POWER PROJECT	COMBUSTION TURBINES 1	SULFUR IN GAS ASSIGNED MAX 1.2 GR/100 SCF; WORK PRACTICE TO MINIMIZE NHZ SLIP	6.7	LB/H
TX-0498	SIGNAL HILLS WICHITA FALLS POWER LP	TURBINES (3)		1.04	LB/H
WI-0227	PORT WASHINGTON GENERATING STATION	COMBINED CYCLE COMBUSTION TURBINES (4 W/ DUCT BURNER, HRSG)	NATURAL GAS; GOOD COMBUSTION PRACTICES	33	LB/H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
RI-0023	RHODE ISLAND CENTRAL GENCO, LLC	LANDFILL GAS-FIRED COMBUSTION TURBINE		0.024	LB/MMBTU
NY-0101	CORNELL COMBINED HEAT & POWER PROJECT	COMBUSTION TURBINES 4	ULTRA LOW SULFUR DIESEL AT 15 PPM, WORK PRACTICE TO MINIMIZE NH3 SLIP.	8.3	LB/H
NY-0101	CORNELL COMBINED HEAT & POWER PROJECT	COMBUSTION TURBINES 4	ULTRA LOW SULFUR DIESEL AT 15 PPM, WORK PRACTICE TO MINIMIZE NH3 SLIP.	8.3	LB/H
NY-0101	CORNELL COMBINED HEAT & POWER PROJECT	COMBUSTION TURBINES 4	ULTRA LOW SULFUR DIESEL AT 15 PPM, WORK PRACTICE TO MINIMIZE NH3 SLIP.	8.3	LB/H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
*FL-0329	SHELL OFFSHORE INC.	Emergency Generator - Bully	Use of EPA Tier 2 engines w/Low NOx engine design and good combustion practices	0.15	T/YR
*SC-0113	PYRAMAX CERAMICS, LLC	EMERGENCY GENERATORS 1 THRU 8	ENGINES MUST BE CERTIFIED TO COMPLY WITH NSPS, SUBPART IIII.	4	GR/KW-H
*SC-0113	PYRAMAX CERAMICS, LLC	FIRE PUMP	PURCHASE OF CERTIFIED ENGINE BASED ON NSPS, SUBPART IIII.	4	GR/KW-H
*SC-0113	PYRAMAX CERAMICS, LLC	EMERGENCY ENGINE 1 THRU 8	PURCHASE OF CERTIFIED ENGINE.	7.5	GR/KW-H
*SC-0114	GP ALLENDALE LP	FIRE WATER DIESEL PUMP	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	5.9	LB/H
*SC-0114	GP ALLENDALE LP	DIESEL EMERGENCY GENERATOR		11.41	LB/H
*SC-0115	GP CLARENDON LP	DIESEL EMERGENCY GENERATOR	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	11.41	LB/H
*SC-0115	GP CLARENDON LP	FIRE WATER DIESEL PUMP	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	5.9	LB/H
*SD-0005	DEER CREEK STATION	Emergency Generator		0	
*SD-0005	DEER CREEK STATION	Fire Water Pump		0	
AL-0251	HILLABEE ENERGY CENTER	EMERGENCY GENERATOR	GOOD COMBUSTION PRACTICES	0	
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	IC ENGINE, EMERGENCY GENERATOR (2)	LIMITATION OF OPERATING HOURS TO LESS THAN 1200 COMBINED HOURS/YR FOR SN-PBCDF-09 AND SN-PBCDF-10 AND LESS THAN 500 HOURS/YR FOR SN-PBCDF-12.	33.9	LB/H
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	IC ENGINE, EMERGENCY GENERATOR SN-PBCDF-12	OPERATING HOURS LIMIT: < 1200 COMBINED H/YR FOR SN-PBCDF-09 & SN-PBCDF-10, < 500 H/YR FOR SN-PBCDF-12.	4.7	LB/H
AR-0094	JOHN W. TURK JR. POWER PLANT	EMERGENCY GENERATOR AND FIRE PUMP ENGINE	GOOD COMBUSTION	6.4	G/KW-H
AZ-0046	ARIZONA CLEAN FUELS YUMA	DISTILLATE HYDROTREATER CHARGE HEATER	LOW NOX BURNERS	0.033	LB/MMBTU
AZ-0046	ARIZONA CLEAN FUELS YUMA	DISTILLATE HYDROTREATER SPLITTER REBOILER	LOW NOX BURNERS	0.032	LB/MMBTU
AZ-0046	ARIZONA CLEAN FUELS YUMA	EMERGENCY GENERATOR		6.4	G/KW-H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
AZ-0046	ARIZONA CLEAN FUELS YUMA	FIRE WATER PUMPS NOS 1 AND 2		4	G/KW-H
AZ-0051	DRAKE	EMERGENCY GENERATOR		4	G/KW-H
FL-0286	FPL WEST COUNTY ENERGY CENTER	TWO GAS-FUELED 10 MMBTU/H PROCESS HEATERS		0.095	LB/MMBTU
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	TWO NOMINAL 10 MMBTU/H NATURAL GAS-FIRED PROCESS HEATERS	GOOD COMBUSTION	0.095	LB/MMBTU
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	TWO NOMINAL 2,250 KW (~ 21 MMBTU/H) EMERGENCY GENERATORS		6.9	G/B-HP-H
FL-0310	SHADY HILLS GENERATING STATION	2.5 MW EMERGENCY GENERATOR	PURCHASE MODEL IS AT LEAST AS STRINGENT AS THE BACT VALUES, UNDER EPA CERTIFICATION.	6.9	G/HP-H
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	Emergency Diesel Fire Pump, One 600 HP		3	G/HP-H
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	Emergency Generators, Two 2682 HP EA		6.4	G/KW-H
FL-0323	GAINESVILLE RENEWABLE ENERGY CENTER	Emergency Generator - 564 kW	Notification, Recordkeeping and Reporting Requirements	6.4	G/KW-H
FL-0323	GAINESVILLE RENEWABLE ENERGY CENTER	Emergency Diesel Fire Pump - 275 HP	The permittee shall adhere to the compliance testing and certification requirements listed in 40 CFR 60.4211 and maintain records demonstrating fuel usage and quality.	3	G/HP-H
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	Two emergency diesel firewater pump engines	demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII	3	G/HP-H
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	250 Kw Emergency Generator	Use of inherently clean ultra low sulfur distillate (ULSD) fuel oil and GCP	4	G/KW-H
IA-0058	GREATER DES MOINES ENERGY CENTER	FIRE PUMP	RETARDED IGNITION TIMING (3-4) DEGREES	2.55	LB/H
IA-0058	GREATER DES MOINES ENERGY CENTER	EMERGENCY GENERATOR	RETARDED INGITION TIMING (3-4 DEGREES)	22.69	LB/H
IA-0060	HAWKEYE GENERATING, LLC	EMERGENCY GENERATOR	GCP, TIMING RETARD	10.61	LB/H
IA-0060	HAWKEYE GENERATING, LLC	FIRE PUMP	GCP, TIMING RETARD	3.8	LB/H
IA-0067	WALTER SCOTT JR. ENERGY CENTER	DIESEL FIRE PUMP	GOOD COMBUSTION PRACTICES	4.41	LB/MMBTU

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
IA-0067	WALTER SCOTT JR. ENERGY CENTER	EMERGENCY GENERATOR	GOOD COMBUSTION PRACTICES	1.71	LB/MMBTU
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	INDIRECT-FIRED DDGS DRYER	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION	0.04	LB/MMBTU
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	EMERGENCY GENERATOR	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 2 NONROAD). THIS COULD REQUIRE ANY NUMBER OF CONTROL TECHNOLOGIES AND OPERATIONAL REQ. TO MEET THE BACT STANDARD.	4.5	G/B-HP-H
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	FIRE PUMP	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 3 NONROAD). THIS COULD REQUIRE ANY NUMBER OF CONTROL TECHNOLOGIES AND OPERATIONAL REQ. TO MEET THE BACT STANDARD.	2.8	G/B-HP-H
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	EMERGENCY GENERATOR		6.2	G/KW-H
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	FIRE PUMP ENGINE		3.9	G/KW-H
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	2 MW EMERGENCY GENERATOR, SRC25	GOOD COMBUSTION PRACTICES. EPA CERTIFIED PER NSPS IIII	0	
ID-0018	LANGLEY GULCH POWER PLANT	EMERGENCY GENERATOR ENGINE	TIER 2 ENGINE-BASED, GOOD COMBUSTION PRACTICES (GCP)	6.4	G/KW-H
ID-0018	LANGLEY GULCH POWER PLANT	FIRE PUMP ENGINE	TIER 3 ENGINE-BASED GOOD COMBUSTION PRACTICES (GCP)	4	G/KW-H
LA-0211	GARYVILLE REFINERY	EMERGENCY GENERATORS (DOCK & TANK FARM) (21-08 & 22-08)	USE OF DIESEL WITH A SULFUR CONTENT OF 15 PPMV OR LESS	0.031	LB/HP-H
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	DIESEL EMERGENCY GENERATOR NOS. 1 & 2	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN INCORPORATING FUEL INJECTION TIMING RETARDATION (ITR)	37.95	LB/H
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	FIREWATER PUMP DIESEL ENGINE	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN INCORPORATING FUEL INJECTION TIMING RETARDATION (ITR)	10.07	LB/H
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	FIREWATER PUMP DIESEL ENGINE	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN INCORPORATING FUEL INJECTION TIMING RETARDATION (ITR)	6.74	LB/H
MD-0036	DOMINION	EMERGENCY GENERATOR (NATURAL GAS)	GOOD COMB PRACTICES; PROPER O&M PLAN; LIMIT ON OPERATIONS<=200H DURING ANY CONSECUTIVE 12-MONTH PERIOD; EXCLUSIVE USE OF LOW SULFUR NG	2	G/B-HP-H
MD-0036	DOMINION	EMERGENCY GENERATOR (DIESEL)	GOOD COMB PRACTICES; PROPER O&M PLAN; LIMIT ON OPERATIONS<=200H DURING ANY CONSECUTIVE 12-MONTH PERIOD	3.66	G/B-HP-H
MD-0040	CPV ST CHARLES	INTERNAL COMBUSTION ENGINE - EMERGENCY FIRE WATER PUMP		3	G/HP-H
MD-0040	CPV ST CHARLES	INTERNAL COMBUSTION ENGINE - EMERGENCY GENERATOR		4.8	G/HP-H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
MI-0390	WHITE PIGEON COMPRESSOR STATION - PLANT #3	EMERGENCY GENERATOR		0.5	G/B-HP-H
MN-0071	FAIRBAULT ENERGY PARK	EMERGENCY GENERATOR		0.024	LB/HP-H
MS-0056	SOUTHERN NATURAL GAS CO. - ENTERPRISE COMPRESSOR	IC ENGINE, COMPRESSOR ENGINE, NATURAL GAS(2)	USE OF LOW EMISSION (OR CLEAN BURN) TECHNOLOGY	7.3	LB/H
MT-0022	BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	IC ENGINE, EMERGENCY GENERATOR	LIMITED HOURS OF OPERATION TO 200 H/YR	97.7	% REDUCTION
NC-0101	FORSYTH ENERGY PLANT	IC ENGINE, EMERGENCY FIREWATER PUMP		36.48	LB/H
NC-0101	FORSYTH ENERGY PLANT	IC ENGINE, EMERGENCY GENERATOR		36.48	LB/H
NC-0105	UNIVERSITY OF NORTH CAROLINA - CHAPEL HILL	EMERGENCY GENERATORS	BACT DOES NOT APPLY TO NONPROFIT EDUCATIONAL INSTITUTIONS	0	
NC-0112	NUCOR STEEL	DIESEL FIRED EMERGENCY GENERATORS AND DIESEL FIRED EMERGENCY WATER PUMPS	OPERATION LIMITED TO 100 HOURS OF OPERATION FOR EACH EMERGENCY GENERATOR AND WATER PUMP PER 12 MONTH PERIOD	0	
NH-0015	CONCORD STEAM CORPORATION	EMRGENCY GENERATOR 1	LESS THAN 500 HOURS OF OPERATION PER CONSECUTIVE 12 MONTH PERIOD	1.98	LB/MMBTU
NH-0015	CONCORD STEAM CORPORATION	EMERGENCY GENERATOR 2	OPERATES LESS THAN 500 HOURS PER CONSECUTIVE 12 MONTH PERIOD.	1.98	LB/MMBTU
NJ-0043	LIBERTY GENERATING STATION	DIESEL FIRE PUMP	NONE	15.5	LB/H
NJ-0043	LIBERTY GENERATING STATION	EMERGENCY GENERATOR	NONE	26.2	LB/H
NV-0050	MGM MIRAGE	DIESEL EMERGENCY GENERATORS - UNITS CC009 THRU CC015 AT CITY CENTER	TURBOCHARGER AAND AFTER-COOLER	0.01	LB/HP-H
NV-0050	MGM MIRAGE	EMERGENCY GENERATORS - UNITS LX024 AND LX025 AT LUXOR	TURBOCHARGING, AFTER-COOLING, AND LEAN-BURN TECHNOLOGY	0.0131	LB/HP-H
OH-0262	ANR	EMERGENCY GENERATOR	NATURAL GAS ONLY FUEL, GOOD COMBUSTION	16.3	LB/H
OH-0317	OHIO RIVER CLEAN FUELS, LLC	EMERGENCY GENERATOR	GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN, IGNITION TIMING RETARD, TURBOCHARGER, AND LOW-TEMPERATURE AFTERCOOLER	26.47	LB/H
OH-0317	OHIO RIVER CLEAN FUELS, LLC	FIRE PUMP ENGINES (2)	GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN, IGNITION TIMING RETARD, TURBOCHARGER, AND LOW-TEMPERATURE AFTERCOOLER	4.89	LB/H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
OK-0056	HORSESHOE ENERGY PROJECT	DIESEL ENGINE, FIRE WATER PUMP	ENGINE DESIGN	4.41	LB/MMBTU
OK-0056	HORSESHOE ENERGY PROJECT	DIESEL ENGINE, EMERGENCY GENERATOR	GOOD COMBUSTION DESIGN	3.2	LB/MMBTU
OK-0072	REDBUD POWER PLT	DIESEL ENGINE, FIRE WATER PUMP		0.031	LB/B-HP-H
OK-0072	REDBUD POWER PLT	DIESEL ENGINE, EMERGENCY GENERATOR		0.024	LB/B-HP-H
OK-0091	CARDINAL FG CO./ CARDINAL GLASS PLANT	IC ENGINES, EMERGENCY GENERATORS (2)	ENGINE DESIGN AND LIMIT ON HOURS OF OPERATION (<500 H/YR)	2.035	LB/MMBTU
OK-0128	MID AMERICAN STEEL ROLLING MILL	Emergency Generator	500 hours per year operations	15.6	LB/H
PA-0264	WYETH PHARMACUETICALS	EMERGENCY GENERATORS (6)		128.74	LB/H
PA-0271	MERCK & CO. WESTPOINT	MOBILE EMERGENCY GENERATOR		6.8	G/B-HP-H
PA-0274	ALLEGHENY LUDLUM CORPORATION - BRACKENRIDGE FACILITY	EMERGENCY GENERATOR #1 (EG-01)		9.2	G/KW-H
PA-0274	ALLEGHENY LUDLUM CORPORATION - BRACKENRIDGE FACILITY	EMERGENCY GENERATOR #2 (EG-02)		6.4	G/KW-H
TX-0407	STERNE ELECTRIC GENERATING FACILITY	EMERGENCY GENERATOR		41.9	LB/H
TX-0407	STERNE ELECTRIC GENERATING FACILITY	FIRE WATER PUMP		9.3	LB/H
TX-0445	SMI TEXAS	120 HP WATER EMERGENCY STANDBY ENGINE		3.72	LB/H
TX-0445	SMI TEXAS	1600 HP CASTER EMERGENCY GENERATOR		38.4	LB/H
TX-0445	SMI TEXAS	300-HP EMERGENCY GENERATOR		9.3	LB/H
TX-0446	JASPER ORIENTED STRANDBOARD MILL	EMERGENCY GENERATOR		11.84	LB/H
TX-0447	CARHAGE ORIENTED STRANDBOARD MILL	EMERGENCY GENERATOR		11.84	LB/H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
TX-0457	CITY PUBLIC SERVICE LEON CREEK PLANT	EMERGENCY GENERATOR (5)		41.9	LB/H
TX-0458	JACK COUNTY POWER PLANT	EMERGENCY GENERATOR (6)		20.8	LB/H
TX-0458	JACK COUNTY POWER PLANT	FIRE WATER PUMP ENGINE		6.2	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	DIESEL EMERGENCY GENERATOR (N7900LJD)		9.13	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	DIESEL EMERGENCY GENERATOR		13.4	LB/H
TX-0481	AIR PRODUCTS BAYTOWN I I	EMERGENCY GENERATOR		10.4	LB/H
WA-0297	NORTHWEST PIPELINE CORPORATION MT. VERNON	IC ENGINE, EMERGENCY GENERATOR	CLEAN FUEL, HOURS LIMIT (500 H/YR)	82	G/H
WA-0328	BP CHERRY POINT COGENERATION PROJECT	EMERGENCY GENERATOR	THE ENGINE MUST BE NEW AND MUST SATISFY THE FEDERAL ENGINE STANDARDS OF 40 CFR 89 FOR YEAR OF PURCHASE.	0	
WV-0023	MAIDSVILLE	IC ENGINE, FIRE WATER PUMP	COMBUSTION CONTROLS WITH OPERATIONAL LIMITATIONS	10.5	LB/H
WV-0023	MAIDSVILLE	EMERGENCY GENERATOR	GOOD COMBUSTION PRACTICES	20.9	LB/H
WY-0064	DRY FORK STATION	DIESEL-FIRED EMERGENCY GENERATOR	EPA TIER II CERTIFED ENGINE WITH 500 HOURS OF OPERATION	4.8	G/HP-H
WY-0064	DRY FORK STATION	DIESEL-FIRED FIRE PUMP ENGINE	TIER II CERTIFIED ENGINE-500 HOURS OF ANNUAL OPERATION	4.8	G/HP-H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
*SC-0113	PYRAMAX CERAMICS, LLC	FIRE PUMP	ENGINES CERTIFIED TO MEET NSPS, SUBPART IIII. HOURS OF OPERATION LIMITED TO 100 HOURS PER YEAR FOR MAINTENANCE AND TESTING.	3.5	GR/KW-H
*SC-0113	PYRAMAX CERAMICS, LLC	EMERGENCY GENERATORS 1 THRU 8	ENGINES MUST BE CERTIFIED TO COMPLY WITH NSPS, SUBPART IIII.	3.5	GR/KW-H
*SC-0113	PYRAMAX CERAMICS, LLC	EMERGENCY ENGINE 1 THRU 8	PURCHASE OF CERTIFIED ENGINE. HOURS OF OPERATION LIMITED TO 100 HOURS FOR MAINTENANCE AND TESTING.	5.5	GR/KW-H
*SC-0114	GP ALLENDALE LP	FIRE WATER DIESEL PUMP	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	1.27	LB/H
*SC-0114	GP ALLENDALE LP	DIESEL EMERGENCY GENERATOR		3.03	LB/H
*SC-0115	GP CLARENDON LP	FIRE WATER DIESEL PUMP	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	1.27	LB/H
*SC-0115	GP CLARENDON LP	DIESEL EMERGENCY GENERATOR	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	3.03	LB/H
*SD-0005	DEER CREEK STATION	Emergency Generator		0	
*SD-0005	DEER CREEK STATION	Fire Water Pump		0	
AL-0251	HILLABEE ENERGY CENTER	EMERGENCY GENERATOR	GOOD COMBUSTION PRACTICES	0	
AR-0094	JOHN W. TURK JR. POWER PLANT	EMERGENCY GENERATOR AND FIRE PUMP ENGINE		3.5	G/KW-H
AZ-0046	ARIZONA CLEAN FUELS YUMA	FIRE WATER PUMPS NOS 1 AND 2		3.5	G/KW-H
AZ-0046	ARIZONA CLEAN FUELS YUMA	EMERGENCY GENERATOR		3.5	G/KW-H
AZ-0051	DRAKE	EMERGENCY GENERATOR		3.5	G/KW-H
FL-0286	FPL WEST COUNTY ENERGY CENTER	FOUR 2250 KW LIQUID FUEL EMERGENCY GENERATORS		8.5	G/B-HP-H
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	TWO NOMINAL 2,250 KW (~ 21 MMBTU/H) EMERGENCY GENERATORS		8	G/B-HP-H
FL-0310	SHADY HILLS GENERATING STATION	2.5 MW EMERGENCY GENERATOR	PURCHASED MODEL IS AT LEAST AS STRINGENT AS THE BACT VALUES UNDER EPA'S CERTIFICATION.	8.5	G/HP-H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
FL-0318	HIGHLANDS ETHANOL FACILITY	Emergency Fired Pump		0	
FL-0318	HIGHLANDS ETHANOL FACILITY	Emergency Generators		3.5	G/KW-H
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	Emergency Generators, Two 2682 HP EA		3.5	G/KW-H
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	Emergency Diesel Fire Pump, One 600 HP		2.6	G/HP-H
FL-0323	GAINESVILLE RENEWABLE ENERGY CENTER	Emergency Generator - 564 kW	Notification, Recordkeeping and Reporting Requirements	3.5	G/KW-H
FL-0323	GAINESVILLE RENEWABLE ENERGY CENTER	Emergency Diesel Fire Pump - 275 HP	testing and certification requirements listed in 40 CFR 60.4211 and maintain records demonstrating fuel usage and quality.	2.6	G/HP-H
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	Two emergency diesel firewater pump engines	demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII	2.6	G/HP-H
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	250 Kw Emergency Generator	Use of inherently clean ultra low sulfur distillate (ULSD) fuel oil and GCP	3.5	G/KW-H
IA-0058	GREATER DES MOINES ENERGY CENTER	EMERGENCY GENERATOR		2.86	LB/H
IA-0058	GREATER DES MOINES ENERGY CENTER	FIRE PUMP		2.21	LB/H
IA-0060	HAWKEYE GENERATING, LLC	EMERGENCY GENERATOR	GCP, TIMING RETARD	0.22	LB/H
IA-0060	HAWKEYE GENERATING, LLC	FIRE PUMP	GCP, TIMING RETARD	4.7	LB/H
IA-0067	WALTER SCOTT JR. ENERGY CENTER	EMERGENCY GENERATOR	GOOD COMBUSTION PRACTICES	0.85	LB/MMBTU
IA-0067	WALTER SCOTT JR. ENERGY CENTER	DIESEL FIRE PUMP	GOOD COMBUSTION PRACTICES	0.95	LB/MMBTU
IA-0084	ADM POLYMERS	FIRE PUMP ENGINE	GOOD COMBUSTION PRACTICES	2.6	G/B-HP-H
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	EMERGENCY GENERATOR	THIS COULD REQUIRE ANY NUMBER OF CONTROL TECHNOLOGIES AND OPERATIONAL REQ. TO MEET THE BACT STANDARD.	2.6	G/B-HP-H
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	FIRE PUMP	HIS COULD REQUIRE ANY NUMBER OF CONTROL TECHNOLOGIES AND OPERATIONAL REQ. TO MEET THE BACT STANDARD.	2.6	G/B-HP-H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	EMERGENCY GENERATOR		3.5	G/KW-H
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	FIRE PUMP ENGINE		3.5	G/KW-H
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	500 KW EMERGENCY GENERATOR, FIRE PUMP, SRC26	GOOD COMBUSTION PRACTICES. EPA CERTIFICATION PER NSPS IIII.	0	
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	2 MW EMERGENCY GENERATOR, SRC25	GOOD COMBUSTION PRACTICES. EPA CERTIFIED PER NSPS IIII	0	
ID-0018	LANGLEY GULCH POWER PLANT	EMERGENCY GENERATOR ENGINE	TIER 2 ENGINE-BASED, GOOD COMBUSTION PRACTICES (GCP)	3.5	G/KW-H
ID-0018	LANGLEY GULCH POWER PLANT	FIRE PUMP ENGINE	TIER 3 ENGINE-BASED, GOOD COMBUSTION PRACTICES (GCP)	0	
LA-0211	GARYVILLE REFINERY	EMERGENCY GENERATORS (DOCK & TANK FARM) (21-08 & 22-08)	USE OF DIESEL WITH A SULFUR CONTENT OF 15 PPMV OR LESS	0.0067	LB/HP-H
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	FIREWATER PUMP DIESEL ENGINE	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN INCORPORATING FUEL INJECTION TIMING RETARDATION (ITR)	0.3	LB/H
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	FIREWATER PUMP DIESEL ENGINE	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN INCORPORATING FUEL INJECTION TIMING RETARDATION (ITR)	1.6	LB/H
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	DIESEL EMERGENCY GENERATOR NOS. 1 & 2	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN INCORPORATING FUEL INJECTION TIMING RETARDATION (ITR)	12.24	LB/H
MD-0036	DOMINION	EMERGENCY GENERATOR (NATURAL GAS)	GOOD COMB PRACTICES; PROPER O&M PLAN; LIMIT ON OPERATIONS<=200H DURING ANY CONSECUTIVE 12-MONTH PERIOD; EXCLUSIVE USE OF LOW SULFUR NG	1.5	G/B-HP-H
MD-0036	DOMINION	EMERGENCY GENERATOR (DIESEL)	GOOD COMB PRACTICES; PROPER O&M PLAN; LIMIT ON OPERATIONS<=200H DURING ANY CONSECUTIVE 12-MONTH PERIOD	0.47	G/B-HP-H
MD-0040	CPV ST CHARLES	INTERNAL COMBUSTION ENGINE - EMERGENCY FIRE WATER PUMP		2.6	G/HP-H
MD-0040	CPV ST CHARLES	INTERNAL COMBUSTION ENGINE - EMERGENCY GENERATOR		2.6	G/HP-H
MI-0389	KARN WEADOCK GENERATING COMPLEX	FIRE PUMP	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL	2.6	G/HP-H
MI-0389	KARN WEADOCK GENERATING COMPLEX	EMERGENCY GENERATOR	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	3.5	G/KW-H
MI-0389	KARN WEADOCK GENERATING COMPLEX	FIRE BOOSTER PUMP	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	5	G/KW-H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
MI-0389	KARN WEADOCK GENERATING COMPLEX	FLUE GAS DESULFURIZATION QUENCH PUMP	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	3.5	G/KW-H
MN-0071	FAIRBAULT ENERGY PARK	EMERGENCY GENERATOR		0.0055	LB/HP-H
MT-0022	BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	IC ENGINE, EMERGENCY GENERATOR	LIMITED TO 200 HOURS OF OPERATION PER YEAR	97.7	% REDUCTION
NC-0101	FORSYTH ENERGY PLANT	IC ENGINE, EMERGENCY GENERATOR		9.69	LB/H
NC-0101	FORSYTH ENERGY PLANT	IC ENGINE, EMERGENCY FIREWATER PUMP		9.69	LB/H
NC-0112	NUCOR STEEL	DIESEL FIRED EMERGENCY GENERATORS AND DIESEL FIRED EMERGENCY WATER PUMPS	OPERATION LIMITED TO 100 HOURS OF OPERATION FOR EACH EMERGENCY GENERATOR AND WATER PUMP PER 12 MONTH PERIOD	0	
NJ-0043	LIBERTY GENERATING STATION	EMERGENCY GENERATOR	NONE	11.1	LB/H
NJ-0043	LIBERTY GENERATING STATION	DIESEL FIRE PUMP	NONE	3.3	LB/H
NV-0050	MGM MIRAGE	DIESEL EMERGENCY GENERATORS - UNITS CC009 THRU CC015 AT CITY CENTER	TURBOCHARGER AND GOOD COMBUSTION PRACTICES	0.0017	LB/HP-H
NV-0050	MGM MIRAGE	EMERGENCY GENERATORS - UNITS LX024 AND LX025 AT LUXOR	TURBOCHARGER AND GOOD COMBUSTION PRACTICES	0.0018	LB/HP-H
OH-0262	ANR	EMERGENCY GENERATOR	NATURAL GAS ONLY FUEL, GOOD COMBUSTION	14.9	LB/H
OH-0317	OHIO RIVER CLEAN FUELS, LLC	EMERGENCY GENERATOR	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN	15.18	LB/H
OH-0317	OHIO RIVER CLEAN FUELS, LLC	FIRE PUMP ENGINES (2)	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN	1.72	LB/H
OK-0056	HORSESHOE ENERGY PROJECT	DIESEL ENGINE, EMERGENCY GENERATOR	GOOD COMBUSTION DESIGN AND PRACTICES	0.85	LB/MMBTU
OK-0056	HORSESHOE ENERGY PROJECT	DIESEL ENGINE, FIRE WATER PUMP	GOOD COMBUSTION PRACTICES AND DESIGN	0.95	LB/MMBTU
OK-0072	REDBUD POWER PLT	DIESEL ENGINE, EMERGENCY GENERATOR	ENGINE DESIGN	0.055	LB/B-HP-H
OK-0072	REDBUD POWER PLT	DIESEL ENGINE, FIRE WATER PUMP	ENGINE DESIGN	0.0067	LB/B-HP-H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
OK-0091	CARDINAL FG CO./ CARDINAL GLASS PLANT	IC ENGINES, EMERGENCY GENERATORS (2)	ENGINE DESIGN AND LIMIT ON HOURS OF OPERATION (<500 H/YR)	0.202	LB/MMBTU
OK-0110	MUSKOGEE PORCELAIN FLOOR TILE PLT	EMERGENCY GENERATORS	GOOD COMBUSTION	0.0067	LB/HP-H
OK-0111	MUSKOGEE PORCELAIN FLOOR TILE PLT	EMERGENCY GENERATORS	GOOD COMBUSTION	0.0067	LB/HP-H
OK-0128	MID AMERICAN STEEL ROLLING MILL	Emergency Generator		6.6	LB/H
PA-0257	SUNNYSIDE ETHANOL,LLC	EMERGENCY GENERATORS		0.29	G/B-HP-H
PA-0271	MERCK & CO. WESTPOINT	MOBILE EMERGENCY GENERATOR		0.78	G/B-HP-H
PA-0274	ALLEGHENY LUDLUM CORPORATION - BRACKENRIDGE FACILITY	EMERGENCY GENERATOR #1 (EG-01)		11.4	G/KW-H
PA-0274	ALLEGHENY LUDLUM CORPORATION - BRACKENRIDGE FACILITY	EMERGENCY GENERATOR #2 (EG-02)		3.5	G/KW-H
TX-0407	STERNE ELECTRIC GENERATING FACILITY	EMERGENCY GENERATOR		9.02	LB/H
TX-0407	STERNE ELECTRIC GENERATING FACILITY	FIRE WATER PUMP		2	LB/H
TX-0445	SMI TEXAS	300-HP EMERGENCY GENERATOR		2	LB/H
TX-0445	SMI TEXAS	1600 HP CASTER EMERGENCY GENERATOR		8.8	LB/H
TX-0445	SMI TEXAS	120 HP WATER EMERGENCY STANDBY ENGINE		0.802	LB/H
TX-0446	JASPER ORIENTED STRANDBOARD MILL	EMERGENCY GENERATOR		5.42	LB/H
TX-0446	JASPER ORIENTED STRANDBOARD MILL	FIRE WATER PUMP		4.54	LB/H
TX-0447	CARHAGE ORIENTED STRANDBOARD MILL	EMERGENCY GENERATOR		5.42	LB/H
TX-0447	CARHAGE ORIENTED STRANDBOARD MILL	FIRE WATER PUMP		1.25	LB/H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
TX-0448	SID RICHARDSON CARBON BORGER PLANT	EMERGENCY GENERATOR		3.87	LB/H
TX-0457	CITY PUBLIC SERVICE LEON CREEK PLANT	EMERGENCY GENERATOR (5)		9	LB/H
TX-0458	JACK COUNTY POWER PLANT	FIRE WATER PUMP ENGINE		3.8	LB/H
TX-0458	JACK COUNTY POWER PLANT	EMERGENCY GENERATOR (6)		12.6	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	DIESEL EMERGENCY GENERATOR		0.44	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	DIESEL EMERGENCY GENERATOR (N7900LJD)		3.52	LB/H
WV-0023	MAIDSVILLE	EMERGENCY GENERATOR	GOOD COMBUSTION PRACTICES	8.85	LB/H
WV-0023	MAIDSVILLE	IC ENGINE, FIRE WATER PUMP	GOOD COMBUSTION PRACTICES	4.43	LB/H
WY-0064	DRY FORK STATION	DIESEL-FIRED EMERGENCY GENERATOR	TIER II CERTIFIED ENGINE-500 HOURS OF ANNUAL OPERATION	2.6	G/HP-H
WY-0064	DRY FORK STATION	DIESEL-FIRED FIRE PUMP ENGINE	TIER II CERTIFIED ENGINE-500 HOURS OF ANNUAL OPERATION	2.6	G/HP-H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
*SC-0114	GP ALLENDALE LP	FIRE WATER DIESEL PUMP	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.41	LB/H
*SC-0114	GP ALLENDALE LP	FIRE WATER DIESEL PUMP	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.41	LB/H
*SC-0114	GP ALLENDALE LP	DIESEL EMERGENCY GENERATOR		0.2	LB/H
*SC-0114	GP ALLENDALE LP	DIESEL EMERGENCY GENERATOR		0.25	LB/H
*SC-0115	GP CLARENDON LP	FIRE WATER DIESEL PUMP	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.41	LB/H
*SC-0115	GP CLARENDON LP	DIESEL EMERGENCY GENERATOR	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.2	LB/H
*SC-0115	GP CLARENDON LP	FIRE WATER DIESEL PUMP	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.41	LB/H
*SC-0115	GP CLARENDON LP	DIESEL EMERGENCY GENERATOR	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.25	LB/H
*SD-0005	DEER CREEK STATION	Emergency Generator		0	
*SD-0005	DEER CREEK STATION	Fire Water Pump		0	
AL-0251	HILLABEE ENERGY CENTER	EMERGENCY GENERATOR	LOW SULFUR DIESEL FUEL	0	
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	IC ENGINE, EMERGENCY GENERATOR (2)	LIMITATION OF OPERATING HOURS TO LESS THAN 1200 COMBINED HOURS/YR FOR SN-PBCDF-09 AND SN-PBCDF-10 AND LESS THAN 500 HOURS/YR FOR SN-PBCDF-12.	1.1	LB/H
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	IC ENGINE, EMERGENCY GENERATOR SN-PBCDF-12	OPERATING HOURS LIMIT: < 500 H/YR	0.4	LB/H
AR-0094	JOHN W. TURK JR. POWER PLANT	EMERGENCY GENERATOR AND FIRE PUMP ENGINE		0.2	G/KW-H
AZ-0046	ARIZONA CLEAN FUELS YUMA	FIRE WATER PUMPS NOS 1 AND 2		0.2	G/KW-H
AZ-0046	ARIZONA CLEAN FUELS YUMA	EMERGENCY GENERATOR		0.02	G/KW-H
AZ-0051	DRAKE	EMERGENCY GENERATOR		0.2	G/KW-H
FL-0286	FPL WEST COUNTY ENERGY CENTER	FOUR 2250 KW LIQUID FUEL EMERGENCY GENERATORS		0.4	G/B-HP-H
FL-0286	FPL WEST COUNTY ENERGY CENTER	ONE EMERGENCY DIESEL FIRED PUMP AND 500 GALLON STORAGE TANK		0.4	G/B-HP-H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	TWO NOMINAL 2,250 KW (~ 21 MMBTU/H) EMERGENCY GENERATORS		0.4	G/B-HP-H
FL-0310	SHADY HILLS GENERATING STATION	2.5 MW EMERGENCY GENERATOR	FIRING ULSO WITH A MAXIMUM SULFUR CONTENT OF 0.0015% BY WEIGHT AND A MAXIMUM HOURS OF OPERATION OF 500 HOUR/YR.	0.4	G/HP-H
FL-0310	SHADY HILLS GENERATING STATION	2.5 MW EMERGENCY GENERATOR	FIRING ULSO WITH A MAXIMUM SULFUR CONTENT OF 0.0015% BY WEIGHT AND A MAXIMUM HOURS OF OPERATION OF 500 HOUR/YR.	0.4	G/HP-H
FL-0318	HIGHLANDS ETHANOL FACILITY	Emergency Fired Pump		0.15	G/HP-H
FL-0318	HIGHLANDS ETHANOL FACILITY	Emergency Generators		0.2	G/KW-H
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	Emergency Generators, Two 2682 HP EA		0.2	G/KW-H
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	Emergency Diesel Fire Pump, One 600 HP		0.15	G/HP-H
FL-0323	GAINESVILLE RENEWABLE ENERGY CENTER	Emergency Generator - 564 kW	Notification, Recordkeeping and Reporting Requirements	0.2	G/KW-H
FL-0323	GAINESVILLE RENEWABLE ENERGY CENTER	Emergency Diesel Fire Pump - 275 HP	The permittee shall adhere to the compliance testing and certification requirements listed in 40 CFR 60.4211 and maintain records demonstrating fuel usage and quality.	0.15	G/HP-H
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	Two emergency diesel firewater pump engines	demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII	0.15	G/HP-H
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	250 Kw Emergency Generator	Use of inherently clean ultra low sulfur distillate (ULSD) fuel oil and GCP & demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII	0.2	G/KW-H
IA-0058	GREATER DES MOINES ENERGY CENTER	EMERGENCY GENERATOR		0.95	LB/H
IA-0058	GREATER DES MOINES ENERGY CENTER	FIRE PUMP		0.56	LB/H
IA-0060	HAWKEYE GENERATING, LLC	EMERGENCY GENERATOR	GCP, TIMING RETARD	0.34	LB/H
IA-0060	HAWKEYE GENERATING, LLC	EMERGENCY GENERATOR	GCP, TIMING RETARD	0.34	LB/H
IA-0060	HAWKEYE GENERATING, LLC	FIRE PUMP	GCP, TIMING RETARD	0.22	LB/H
IA-0060	HAWKEYE GENERATING, LLC	FIRE PUMP	GCP, TIMING RETARD	0.22	LB/H
IA-0067	WALTER SCOTT JR. ENERGY CENTER	EMERGENCY GENERATOR	GOOD COMBUSTION PRACTICES	0.14	LB/MMBTU
IA-0067	WALTER SCOTT JR. ENERGY CENTER	EMERGENCY GENERATOR	GOOD COMBUSTION PRACTICES	0.14	LB/MMBTU

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
IA-0067	WALTER SCOTT JR. ENERGY CENTER	DIESEL FIRE PUMP	GOOD COMBUSTION PRACTICES	0.31	LB/MMBTU
IA-0067	WALTER SCOTT JR. ENERGY CENTER	DIESEL FIRE PUMP	GOOD COMBUSTION PRACTICES	0.31	LB/MMBTU
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	EMERGENCY GENERATOR	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 2 NONROAD).	0.15	G/B-HP-H
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	EMERGENCY GENERATOR	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 2 NONROAD).	0.15	G/B-HP-H
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	FIRE PUMP	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 3 NONROAD).	0.15	G/B-HP-H
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	FIRE PUMP	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 3 NONROAD).	0.15	G/B-HP-H
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	EMERGENCY GENERATOR		0.2	G/KW-H
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	FIRE PUMP ENGINE		0.2	G/KW-H
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	EMERGENCY GENERATOR		0.2	G/KW-H
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	FIRE PUMP ENGINE		0.2	G/KW-H
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	500 KW EMERGENCY GENERATOR, FIRE PUMP, SRC26	ULSD FUEL, EPA CERTIFICATION PER NSPS IIII	0	
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	500 KW EMERGENCY GENERATOR, FIRE PUMP, SRC26	ULSD FUEL, EPA CERTIFICATION PER NSPS IIII	0	
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	2 MW EMERGENCY GENERATOR, SRC25	ULSD FUEL, GOOD COMBUSTION PRACTICES, EPA CERTIFIED PER NSPS IIII	0	
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	2 MW EMERGENCY GENERATOR, SRC25	ULSD FUEL, GOOD COMBUSTION PRACTICES, EPA CERTIFIED PER NSPS IIII	0	
ID-0018	LANGLEY GULCH POWER PLANT	EMERGENCY GENERATOR ENGINE	TIER 2 ENGINE-BASED, GOOD COMBUSTION PRACTICES (GCP)	0.2	G/KW-H
ID-0018	LANGLEY GULCH POWER PLANT	FIRE PUMP ENGINE	TIER 3 ENGINE-BASED, GOOD COMBUSTION PRACTICES (GCP)	0.2	G/KW-H
LA-0211	GARYVILLE REFINERY	EMERGENCY GENERATORS (DOCK & TANK FARM) (21-08 & 22-08)	USE OF DIESEL WITH A SULFUR CONTENT OF 15 PPMV OR LESS	0.0022	LB/HP-H
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	FIREWATER PUMP DIESEL ENGINE	GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN, AND USE OF LOW SULFUR AND LOW ASH DIESEL	0.64	LB/H
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	FIREWATER PUMP DIESEL ENGINE	GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN, AND USE OF LOW SULFUR AND LOW ASH DIESEL	0.28	LB/H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	DIESEL EMERGENCY GENERATOR NOS. 1 & 2	GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN, AND USE OF LOW SULFUR AND LOW ASH DIESEL	0.69	LB/H
LA-0256	COGENERATION PLANT	EMERGENCY GENERATOR	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES	0.01	LB/H
LA-0256	COGENERATION PLANT	EMERGENCY GENERATOR	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES	0.01	LB/H
MD-0036	DOMINION	EMERGENCY GENERATOR (NATURAL GAS)	GOOD COMB PRACTICES; PROPER O&M PLAN; LIMIT ON OPERATIONS<=200H DURING ANY CONSECUTIVE 12-MONTH PERIOD; EXCLUSIVE USE OF LOW SULFUR NG	0.0099	LB/MMBTU
MD-0036	DOMINION	EMERGENCY GENERATOR (DIESEL)	GOOD COMB PRACTICES; PROPER O&M PLAN; LIMIT ON OPERATIONS<=200H DURING ANY CONSECUTIVE 12-MONTH PERIOD; EXCLUSIVE USE LOW SULFUR DIESEL FUEL	0.14	G/B-HP-H
MD-0040	CPV ST CHARLES	INTERNAL COMBUSTION ENGINE - EMERGENCY FIRE WATER PUMP		0.15	G/HP-H
MD-0040	CPV ST CHARLES	INTERNAL COMBUSTION ENGINE - EMERGENCY GENERATOR		0.15	G/HP-H
MD-0040	CPV ST CHARLES	INTERNAL COMBUSTION ENGINE - EMERGENCY FIRE WATER PUMP		0.15	GR-HP-H
MD-0040	CPV ST CHARLES	INTERNAL COMBUSTION ENGINE - EMERGENCY GENERATOR		0.15	G/HP-H
MD-0040	CPV ST CHARLES	INTERNAL COMBUSTION ENGINE - EMERGENCY FIRE WATER PUMP		0.15	G/HP-H
MD-0040	CPV ST CHARLES	INTERNAL COMBUSTION ENGINE - EMERGENCY GENERATOR		0.15	G/HP-H
MI-0389	KARN WEADOCK GENERATING COMPLEX	FIRE PUMP	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.31	LB/MMBTU
MI-0389	KARN WEADOCK GENERATING COMPLEX	EMERGENCY GENERATOR	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.0573	LB/MMBTU
MI-0389	KARN WEADOCK GENERATING COMPLEX	FIRE PUMP	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.15	G/HP-H
MI-0389	KARN WEADOCK GENERATING COMPLEX	EMERGENCY GENERATOR	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.2	G/KW-H
MI-0389	KARN WEADOCK GENERATING COMPLEX	FIRE BOOSTER PUMP		0.31	LB/MMBTU
MI-0389	KARN WEADOCK GENERATING COMPLEX	FIRE BOOSTER PUMP	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.4	G/KW-H
MN-0071	FAIRBAULT ENERGY PARK	EMERGENCY GENERATOR		0.0007	LB/HP-H
MN-0071	FAIRBAULT ENERGY PARK	EMERGENCY GENERATOR		0.0004	LB/HP-H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
NC-0101	FORSYTH ENERGY PLANT	IC ENGINE, EMERGENCY GENERATOR		1.14	LB/H
NC-0101	FORSYTH ENERGY PLANT	IC ENGINE, EMERGENCY FIREWATER PUMP		1.14	LB/H
NC-0112	NUCOR STEEL	DIESEL FIRED EMERGENCY GENERATORS AND DIESEL FIRED EMERGENCY WATER PUMPS	OPERATION LIMITED TO 100 HOURS OF OPERATION FOR EACH EMERGENCY GENERATOR AND WATER PUMP PER 12 MONTH PERIOD	0	
NE-0031	OPPD - NEBRASKA CITY STATION	EMERGENCY GENERATOR		0.001	GR/DSCF
NJ-0043	LIBERTY GENERATING STATION	EMERGENCY GENERATOR	NONE	1.4	LB/H
NJ-0043	LIBERTY GENERATING STATION	DIESEL FIRE PUMP	NONE	1.1	LB/H
NV-0050	MGM MIRAGE	EMERGENCY GENERATORS - UNITS LX024 AND LX025 AT LUXOR	TURBOCHARGER AND GOOD COMBUSTION PRACTICES	0.0001	LB/HP-H
OH-0262	ANR	EMERGENCY GENERATOR	NATURAL GAS ONLY FUEL, GOOD COMBUSTION	0.2	LB/H
OH-0317	OHIO RIVER CLEAN FUELS, LLC	EMERGENCY GENERATOR	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN	0.87	LB/H
OH-0317	OHIO RIVER CLEAN FUELS, LLC	FIRE PUMP ENGINES (2)	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN	0.27	LB/H
OK-0056	HORSESHOE ENERGY PROJECT	DIESEL ENGINE, EMERGENCY GENERATOR	LOW ASH DIESEL FUEL	0.1	LB/MMBTU
OK-0056	HORSESHOE ENERGY PROJECT	DIESEL ENGINE, FIRE WATER PUMP	LOW ASH FUEL	0.31	LB/MMBTU
OK-0091	CARDINAL FG CO./ CARDINAL GLASS PLANT	IC ENGINES, EMERGENCY GENERATORS (2)	ENGINE DESIGN	0.0444	LB/MMBTU
OK-0110	MUSKOGEE PORCELAIN FLOOR TILE PLT	EMERGENCY GENERATORS	GOOD COMBUSTION	0.0022	LB/HP-H
OK-0111	MUSKOGEE PORCELAIN FLOOR TILE PLT	EMERGENCY GENERATORS	GOOD COMBUSTION	0.0022	LB/HP-H
OK-0128	MID AMERICAN STEEL ROLLING MILL	Emergency Generator		0.84	LB/H
PA-0271	MERCK & CO. WESTPOINT	MOBILE EMERGENCY GENERATOR		0.16	G/B-HP-H
PA-0271	MERCK & CO. WESTPOINT	MOBILE EMERGENCY GENERATOR		0.16	G/B-HP-H
PA-0274	ALLEGHENY LUDLUM CORPORATION - BRACKENRIDGE FACILITY	EMERGENCY GENERATOR #1 (EG-01)		0.54	G/KW-H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
PA-0274	ALLEGHENY LUDLUM CORPORATION - BRACKENRIDGE FACILITY	EMERGENCY GENERATOR #2 (EG-02)		0.2	G/KW-H
PA-0274	ALLEGHENY LUDLUM CORPORATION - BRACKENRIDGE FACILITY	EMERGENCY GENERATOR #1 (EG-01)		2.66	LB/H
PA-0274	ALLEGHENY LUDLUM CORPORATION - BRACKENRIDGE FACILITY	EMERGENCY GENERATOR #2 (EG-02)		0.44	LB/H
PA-0274	ALLEGHENY LUDLUM CORPORATION - BRACKENRIDGE FACILITY	EMERGENCY GENERATOR #1 (EG-01)		2.66	LB/H
TX-0407	STERNE ELECTRIC GENERATING FACILITY	EMERGENCY GENERATOR		2.97	LB/H
TX-0407	STERNE ELECTRIC GENERATING FACILITY	FIRE WATER PUMP		0.66	LB/H
TX-0445	SMI TEXAS	300-HP EMERGENCY GENERATOR		0.66	LB/H
TX-0445	SMI TEXAS	1600 HP CASTER EMERGENCY GENERATOR		1.12	LB/H
TX-0445	SMI TEXAS	120 HP WATER EMERGENCY STANDBY ENGINE		0.264	LB/H
TX-0446	JASPER ORIENTED STRANDBOARD MILL	EMERGENCY GENERATOR		4.5	LB/H
TX-0447	CARHAGE ORIENTED STRANDBOARD MILL	EMERGENCY GENERATOR		1.85	LB/H
TX-0457	CITY PUBLIC SERVICE LEON CREEK PLANT	EMERGENCY GENERATOR (5)		3	LB/H
TX-0458	JACK COUNTY POWER PLANT	FIRE WATER PUMP ENGINE		0.5	LB/H
TX-0458	JACK COUNTY POWER PLANT	EMERGENCY GENERATOR (6)		1.5	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	DIESEL EMERGENCY GENERATOR		0.5	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	DIESEL EMERGENCY GENERATOR (N7900LJD)		0.49	LB/H
TX-0481	AIR PRODUCTS BAYTOWN I I	EMERGENCY GENERATOR		0.74	LB/H
WV-0023	MAIDSVILLE	EMERGENCY GENERATOR	GOOD COMBUSTION PRACTICES	1.13	LB/H
WV-0023	MAIDSVILLE	IC ENGINE, FIRE WATER PUMP	GOOD COMBUSTION PRACTICES	0.56	LB/H

RBLCID	FACILITY_NAME	PROCESS_NAME	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
WV-0023	MAIDSVILLE	IC ENGINE, FIRE WATER PUMP	GOOD COMBUSTION PRACTICES	0.56	LB/H
WY-0064	DRY FORK STATION	DIESEL-FIRED EMERGENCY GENERATOR	TIER II CERTIFIED-500 HOURS OF ANNUAL OPERATION	0.15	G/HP-H
WY-0064	DRY FORK STATION	DIESEL-FIRED FIRE PUMP ENGINE	TIER II CERTITIED ENGINE-500 HOURS OF ANNUAL OPERATION.	0.15	G/HP-H