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BUREAU OF AIR REGULATION

September 22, 2008

Mr. Syed Arif, P.E.
Florida Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

ViaEmail: Syed.Arif@dep.state.fl.us
Via FedEx
Airbill No. 7919 5615 3626

Re: Tampa Electric Company – Big Bend Station
Simple-Cycle Combustion Turbine Unit 4
Project No. 0570039-040-AC

Subject: Response to Request for Additional Information – September 19, 2008

Dear Mr. Arif:

Tampa Electric Company (TEC) submitted an air construction permit application to the Department on August 21, 2008 requesting authorization to install and operate two simple cycle combustion turbines at our Big Bend Station. In response to this permit application, the Department requested additional information in correspondence to TEC dated September 19, 2008.

This letter is intended to provide a response to each specific issue raised by the Department and the Hillsborough County Environmental Protection Commission (EPC). For your convenience, TEC has restated each issue followed by our response.

A. Florida Department of Environmental Protection Comments

FDEP-1

Are you planning to convert these simple cycle combustion turbine (SCCT) systems into combined cycle CT systems? If so, when?

TEC Response to FDEP-1

TEC does not plan to convert the simple-cycle combustion turbines (SCCTs) to combined-cycle units. The planned utilization of the SCCTs is described in Section 2.1 of the August 2008 air construction permit application.

FDEP-2

On the application page F. 1. for a SCCT system, a total percent efficiency control value for the pollutant nitrogen oxides (NO_x) is stated as 88%. What is the basis for the value and provide an explanation and/or the reference material to support this value?

TEC Response to FDEP-2

The 88 percent NO_x control efficiency associated with the SCCT water injection system was calculated based on a nominal uncontrolled (i.e., without water injection) NO_x exhaust concentration of 200 parts per million by volume (ppmvd) and a controlled (i.e., with water injection) NO_x exhaust concentration of 25 ppmvd as follows:

*NO_x Control Efficiency = [(200 ppmvd – 25 ppmvd) / 200 ppmvd] * 100 = 87.5 %*

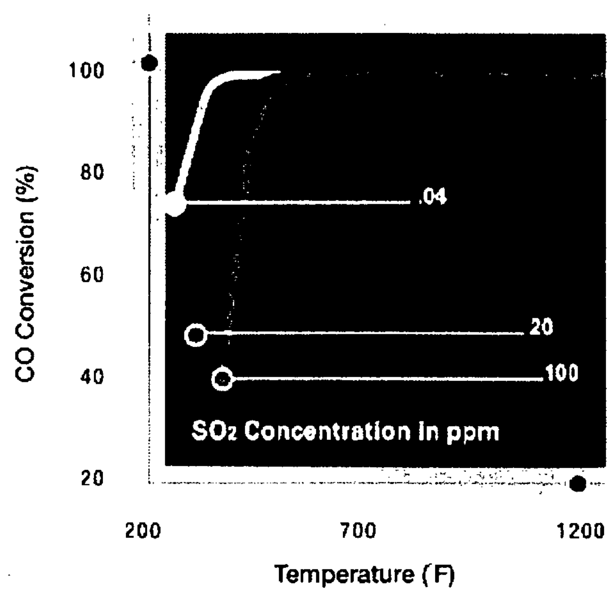
FDEP-3

On the application page F. I. for a SCCT system, a total percent efficiency control value for the pollutant carbon monoxide (CO) is stated as 90%. What is the basis for the value and provide an explanation and/or the reference material to support this value?

TEC Response to FDEP-3

The nominal 90 percent CO oxidation rate for the oxidation catalyst represents a typical CO conversion rate for this control technology. The actual CO oxidation rate of an oxidation catalyst system will depend on a number of variables including inlet CO concentration, residence time, and oxidation catalyst temperature.

Significant CO oxidation will occur at any catalyst temperature above roughly 500°F. As shown in Appendix B, Tables B-18 (for natural gas) and B-19 (for ULSD fuel oil) of the August 2008 air construction permit application, exhaust temperatures for the Pratt & Whitney Power Systems (PWPS) FT8-3® SWIFTPAC® SCCTs range from approximately 700 to 920 °F for both natural gas and ULSD fuel oil. The following graphic shows the relationship between catalyst temperature and CO conversion for a typical oxidation catalyst (data shown is for the BASF CAMET® catalyst; comparable performance would be expected for other catalyst vendors).



Removal efficiency will also vary with gas residence time that is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed. For combustion turbine applications, oxidation catalyst systems are typically designed to achieve a control efficiency of 80 to 90 percent for CO.

The nominal 90 percent control efficiency shown on the FDEP permit application form is consistent with EPA information developed as part of the agency's rulemaking on the combustion turbine Maximum Achievable Control Technology (MACT) National Emission Standard for Hazardous Air Pollutants (NESHAPS). A December 30, 1999 memo from Mr. Sims Roy of EPA's Emissions Standards Division Combustion Group provides a discussion of oxidation catalyst systems. The December 30, 1999 EPA memorandum indicates that "The performance of these oxidation catalyst systems on combustion turbines results in 90-plus percent control of CO and about 85 to 90 percent control of formaldehyde. Similar emission reductions are also achieved on other hazardous air pollutants (HAP) pollutants." Similar language regarding the CO conversion rate of oxidation catalyst control technology is contained in Section 3.1 (Stationary Gas Turbines) of AP-42, Compilation of Air Pollutant Emission Factors; reference Section 3.1.4.3.

FDEP-4

On the application page F. I. for a SCCT system, a total percent efficiency control value for the pollutant volatile organic compounds (VOC) is stated as 50%. What is the basis for the value and provide an explanation and/or the reference material to support this value?

TEC Response to FDEP-4

The nominal 50 percent VOC oxidation rate shown on the FDEP permit application form for the oxidation catalyst represents a typical VOC oxidation rate for this control technology. Similar to CO, the VOC oxidation rate of an oxidation catalyst system will depend on a number of variables including inlet VOC concentration, residence time, catalyst temperature, and specific organic compound among others. In general, unsaturated hydrocarbons such as ethylene are more reactive with oxidation catalysts than saturated species such as ethane. A typical VOC control efficiency using oxidation catalyst is 50 percent.

As noted above in the response to FDEP-1, the EPA reference cited indicates an expected conversion efficiency of formaldehyde and other HAPs in the range of 85 to 90 percent. Since formaldehyde and other organic HAPs are also VOCs, based on the EPA information the 50 percent VOC control efficiency assumed for the Big Bend Station Peaker Project is considered reasonable. This nominal VOC oxidation rate is also consistent with reviews conducted by regulatory agencies for similar projects. For example, in its review of the Sun Valley Energy Project (comprised of aeroderivative SCCTs similar to the PWPS SCCTs), the California Energy Commission concluded that "VOC emissions are expected to be further reduced as a result of the proposed CO oxidation catalyst. The amount of reduction is not estimated herein, but recent data indicate that VOC reductions on the order of 50-90 percent are routinely seen."

FDEP-5

For the proposed emergency diesel engine, where are you going to store the Ultra Low Sulfur Diesel (ULSD) fuel? Is there an existing ULSD fuel storage tank on-site? If so, please describe.

TEC Response to FDEP-5

There is an existing 4 million gallon (constructed prior to July 23, 1984) fuel oil storage tank located to the west of Big Bend Station SCCTs CT-2 and CT-3. This storage tank will be utilized to store ULSD fuel oil for the proposed PWPS FT8-3® SWIFTPAC® SCCTs. However, ULSD fuel oil storage for the emergency generator diesel engine will likely consist of either a small storage tank located near the engine or an integral tank located at the base of the engine.

FDEP-6

Explain how you plan to demonstrate compliance with the NOx emissions standard using the emissions monitoring provisions of title 40, Code of Federal Regulations, Part 75 (40 CFR 75). Provide a detailed plan regarding this issue.

TEC Response to FDEP-6

A detailed Part 75 monitoring plan is not available at this stage of the project. TEC will install NO_x *continuous emissions monitoring systems (CEMS) that comply with the requirements of 40 CFR Part 75. In accordance with 40 CFR §75.4(i)(2), monitoring system certification testing must be completed no later than 90 unit operating days or 180 calendar days (whichever occurs first) after the date the unit commences commercial operation. As required by 40 CFR §75.62, an initial monitoring plan will be submitted at least 21 days prior to the start of monitoring system certification testing. As noted on Page 1-2 of the August 2008 air construction permit application, commencement of commercial operation is planned for May 2009.*

FDEP-7

Please provide a detailed rule applicability determination for the provisions contained in 40 CFR 60, Subpart KKKK, for a SCCT.

TEC Response to FDEP-7

A highlighted version of 40 CFR 60, Subpart KKKK that shows the applicable sections of this New Source Performance Standard is attached – see Attachment 1 to this letter.

B. Hillsborough County Environmental Protection Commission Comments

EPC-1

This AC Permit Application is for construction/installation of a Pratt & Whitney Power System (PWPS) FT8-3 SWIFTPAC unit (CT Unit 4), which is comprised of two (2) SCCTs to one common generator, and also is for construction/installation of a 800 KW Caterpillar diesel engine, which provides electricity to CT Unit 4 in the event of power interruption from the grid. During this co-review, EPC staff acknowledges that the CT Unit 4 and the Caterpillar diesel engine are the identical units that will be installed at TEC Bayside site. However, the manufacturer specifications for these units were not included in the Bayside AC Permit Application dated 3/20/07 and 8/11/08 nor in this Big Bend AC Permit Application, except for information or data prepared and provided by the engineering consultant, ECT. Pursuant to Rules 62-4.070(1) and 62-210.200(244), F.A.C., and in order to verify the potential to emit, please provide design specifications on the SCCT. The specifications should include, but not limited to, design/operation parameters, the turbine heat input at peak load on either natural gas (NG) or ultra low sulfur diesel (ULSD) fuel usage.

TEC Response to EPC-1

PWPS technical data regarding the FT8-3® SWIFTPAC® SCCTs is provided in Attachment 2 to this letter.

EPC-2

Page 16 in the Application indicates that the maximum heat input rates are 342.7 MMBtu/hr for NG and 302.7 MMBtu/hr for ULSD. This AC project is subject to the NSPS, Subpart KKKK. Page 21 in the Application indicates that the NO_x emission standard for ULSD is 42 ppmvd @ 15% O_2, on which the emission estimates in Appendix B, Table B-7 and Table B-11, in the Application are based on. Table I of the NSPS, Subpart KKKK, shows the NO_x emission standard as 74 ppmvd @ 15% O_2 for a new turbine firing fuel other than NG with a range of heat input of 50 - 850 MMBtu/hr. Pursuant to Rule 62-4.070(1), F.A.C., please provide reasonable assurance based on plans, test results and/or manufacturer's information or guarantees that the emission unit can meet the lower 42 ppmvd @ 15% O_2 NO_x emission standard

TEC Response to EPC-2

PWPS has provided estimated emissions showing a NO_x exhaust concentration of 42 ppmvd @ 15% O_2 when firing ULSD fuel oil. This is the typical NO_x exhaust concentration provided by combustion turbine (CT) vendors for liquid fuel-fired CTs that are controlled by wet injection. Numerous liquid fuel-fired CTs that are controlled by wet injection have demonstrated the ability to achieve the 42 ppmvd @ 15% O_2 NO_x concentration; e.g., the Seminole Electric Cooperative Midulla Generating Station PWPS FT8-3® SWIFTPAC® SCCTs. PWPS technical data regarding the FT8-3® SWIFTPAC® SCCTs is provided in Attachment 2 to this letter.

EPC-3

NSPS, Subpart KKKK, regulates and establishes emission standards for NO_x and SO_2. The NO_x and SO_2 PTE emissions estimates in the Application are calculated based on the emissions standards of the Subpart. Pursuant to Rule 62-4.070(1), F.A.C., please explain how the other air pollutants (CO, PM/PM_{10}, VOC, Pb and H_2SO_4 mist) hourly emission rate (lb/hr) are determined for a purpose of PTE estimates. According to the Application, the hourly emission rates, i.e., CO: 9.1 lb/hr; PM/PM_{10}: 7.5 lb/hr; VOC: 5.1 lb/hr, etc, appear to be from the vendor (PWPS) data. Pursuant to Rule 62-4.070(1), F.A.C., please provide justification for the PTE estimates and provide reasonable assurance based on plans, test results and/or manufacturer's information or guarantees that the emission unit can meet these emission rates and PTE limitations. Furthermore, have the emission factors in the AP-42, Table 3.1, been taken into consideration in comparison with the vendor data?

TEC Response to EPC-3

The hourly and annual potential-to-emit (PTE) emission rates for the PWPS FT8-3® SWIFTPAC® SCCTs were calculated based on PWPS estimated emissions data and the maximum annual operating hours proposed for the Big Bend Station Peaker Project. Emission rate calculations were provided in Appendix B, Tables B-1 through B-20 of the August 2008 air construction permit application. PWPS technical data, including estimated emissions, for the FT8-3® SWIFTPAC® SCCTs is provided in Attachment 2 to this letter. A detailed explanation of each Appendix B emission rate calculation is provided in Attachment 3 to this letter. In reviewing the emission rate calculations provided in Appendix B, it was noticed that several tables inadvertently used a 5.0 percent heat input margin instead of the correct 7.0 percent margin. Revised Appendix B tables are provided in Attachment 5 to this letter.

EPC-4

The 800KW Caterpillar DSR4B Generator C27 TA Diesel Engine is subject to NSPS, Subpart IIII. The Section 4.1.2, Page 4-3, in the Application states that the diesel engine will have a displacement of less than 30 liters per cylinder. Pursuant to Rules 62-4.070(1) and 62-210.200(244), F.A.C., and in order to verify the potential to emit, please provide design specifications on the Caterpillar diesel engine. The specifications should include, but not limited to, design/operation parameters, the engine order/manufacture date, the actual displacement per cylinder, manufacturer certifications or engine testing data. In addition, pursuant to 40 CFR 60.4202, it states that *stationary CI internal combustion engine manufacturers must certify their 2007 mode/year and later emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines to the certification emission standards for new marine CI engines in **40 CFR 94.8**, as applicable, for all pollutants, for the same displacement and maximum engine power.* According to Appendix B, Table B-16, in the Application, the emission limits used for PTE estimates are calculated based on NO_x: 5.26 g/hp-hr; CO: 0.26 g/hp-hr; VOC: 0.03 g/hp-hr; $PM/PM_{10}/PM_{2.5}$: 0.024 g/hp-hr and SO_2: 0.004 g/hp-hr. Pursuant to Rule 62-4.070(1), F.A.C., please provide reasonable assurance based on plans, test results and/or manufactures information or guarantees that the emission unit can meet these PTE limitations.

TEC Response to EPC-3

Technical information, including emission rates for the Caterpillar C27 TA emergency diesel engine is provided in Attachment 4 to this letter. The emergency generator diesel engine for the Big Bend Station Peaker Project is expected to be a model year 2007 or later unit with a cylinder displacement less than 10 liters per cylinder and a maximum engine power greater than 50 horsepower (HP). Accordingly, the diesel engine would be subject to the requirements of New Source Performance Standard (NSPS) Subpart IIII 40 CFR §60.4202(a)(2) [for engine manufacturers), and §60.4205(b) [for owners and operators]. Both of these provisions require engine certification to the emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

Note that, beginning with engines manufactured in model year 2007, engine manufacturers are required to produce engines that are certified to comply with NSPS Subpart IIII. Regardless of the specific emission standards that may apply to a particular model year engine, TEC will only purchase an engine for the Big Bend Station Peaker Project that is certified to comply with NSPS Subpart IIII.

TEC understands that with the submission of this additional information and the revised air construction permit application, the Department will continue processing our request for an air construction permit for Big Bend Station simple cycle Unit 4. If you have any further questions regarding this matter, please contact me at (813) 228-1095.

Sincerely,

David M. Lukcic
Manager Environmental Projects
Environmental Health and Safety

Attachments

cc: Mr. Bruce Mitchell, FDEP
Ms. Diana Lee, EPCHC (enc)

bc: B.T. Burrows
A.T. Nguyen
J.M. Ward
R.L. Kelleher
Tom Davis, ECT
C.2.1

EHS/TWD/ATN003

ATTACHMENT 1

RESPONSE TO FDEP-7

APPLICABLE PROVISIONS OF 40 CFR 60, SUBPART KKKK
NEW SOURCE PERFORMANCE STANDARDS
FOR STATIONARY GAS TURBINES

Applicable requirements for natural gas
Applicable requirements for ULSD fuel oil
Applicable requirements for both natural gas and ULSD fuel oil

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

Source: 71 FR 38497, July 6, 2006, unless otherwise noted.

Introduction

§ 60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

Applicability

§ 60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

§ 60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in §60.4420(i), are exempt from the nitrogen oxides (NO_X) emission limits in §60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NO_X emission limits in §60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

Emission Limits

§ 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_X) and sulfur dioxide (SO_2).

§ 60.4320 What emission limits must I meet for nitrogen oxides (NOX)?

(a) You must meet the emission limits for NO_X specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X.

§ 60.4325 What emission limits must I meet for NOX if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

§ 60.4330 What emission limits must I meet for sulfur dioxide (SO2)?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1) or (a)(2) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

General Compliance Requirements

§ 60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

Monitoring

§ 60.4335 How do I demonstrate compliance for NOX if I use water or steam injection?

(a) If you are using water or steam injection to control NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2concentration exceeds 19.0 percent O_2(or the hourly average CO_2concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2or 1.0 percent CO_2(as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_x)_h * (HI)_h}{P} \quad \text{(Eq. 1)}$$

Where:

E = hourly NO_X emission rate, in lb/MWh,

$(NO_X)_h$= hourly NO_X emission rate, in lb/MMBtu,

$(HI)_h$= hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), *e.g.* ; calculated using Equation D–15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \quad \text{(Eq. 2)}$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

$(Pe)_t$= electrical or mechanical energy output of the combustion turbine in MW,

$(Pe)_c$= electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \qquad \text{(Eq. 3)}$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and
3.413 x 10_6= conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_x)_m}{BL * AL} \qquad \text{(Eq. 4)}$$

Where:

E = NO_X emission rate in lb/MWh,

$(NO_X)_m$= NO_X emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in §60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in §60.4380(b)(1).

§ 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NO_X CEMS is chosen:

(a) Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

§ 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm

§ 60.4355 How do I establish and document a proper parameter monitoring plan?

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§60.4335 and 60.4340 must be monitored during the performance test required under §60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO_X emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

§ 60.4340 How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?

(a) If you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. 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, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO_X formation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode.

(iii) For any turbine that uses SCR to reduce NO_X emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in §75.19(c)(1)(iv)(H).

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in §75.19 or the NO_X emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in §75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

§ 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

§ 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

§ 60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.* , flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

Reporting

§ 60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

§ 60.4380 How are excess emissions and monitor downtime defined for NOX?

For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.4320, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NO_X control will also be considered an excess emission.

(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in §§60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3

of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

§ 60.4385 How are excess emissions and monitoring downtime defined for SO_2?

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

§ 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?

(a) If you operate an emergency combustion turbine, you are exempt from the NO_X limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO_X limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

§ 60.4395 When must I submit my reports?

All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

Performance Tests

§ 60.4400 How do I conduct the initial and subsequent performance tests, regarding NOX?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NO_X concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \qquad \text{(Eq. 5)}$$

Where:

E = NO_X emission rate, in lb/MWh

1.194×10^{-7}= conversion constant, in lb/dscf-ppm

$(NO_X)_c$= average NO_X concentration for the run, in ppm

Q_{std}= stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(ii) Measure the NO_X and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NO_X emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NO_X emission rate in lb/MWh.

(2) Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO_2(or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or

(B) For turbines with a NO_X standard greater than 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO_2(or O_2) from the mean for all traverse points; or

(C) For turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2(or O_2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.4320 NO_X emission limit.

(4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in §60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

§ 60.4405 How do I perform the initial performance test if I have chosen to install a NOX-diluent CEMS?

If you elect to install and certify a NO_X-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.

(d) Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

§ 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls in accordance with §60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.4355.

§ 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent SO_2performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

(2) Measure the SO_2concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO_2emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \qquad \text{(Eq. 6)}$$

Where:

E = SO_2emission rate, in lb/MWh

1.664×10^{-7}= conversion constant, in lb/dscf-ppm

$(SO_2)_c$= average SO_2concentration for the run, in ppm

Q_{std}= stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(3) Measure the $SO_2$and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO_2emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO_2emission rate in lb/MWh.

(b) [Reserved]

Definitions

§ 60.4420 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions) of this part.

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

Excess emissions means a specified averaging period over which either (1) the NO_X emissions are higher than the applicable emission limit in §60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore platforms.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

Regenerative cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

Table 1—to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing natural gas, electric generating	≤ 50 MMBtu/h	42 ppm at 15 percent O_2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O_2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating	≤ 50 MMBtu/h	96 ppm at 15 percent O_2 or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MWh).

New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	≤ 30 MW output	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	> 30 MW output	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).

ATTACHMENT 2

RESPONSE TO EPC-1

TECHNICAL DATA FOR PRATT & WHITNEY POWER SYSTEM
FT8-3® SWIFTPAC® SIMPLE CYCLE COMBUSTION TURBINES

SWIFTPAC® **Power Plant**

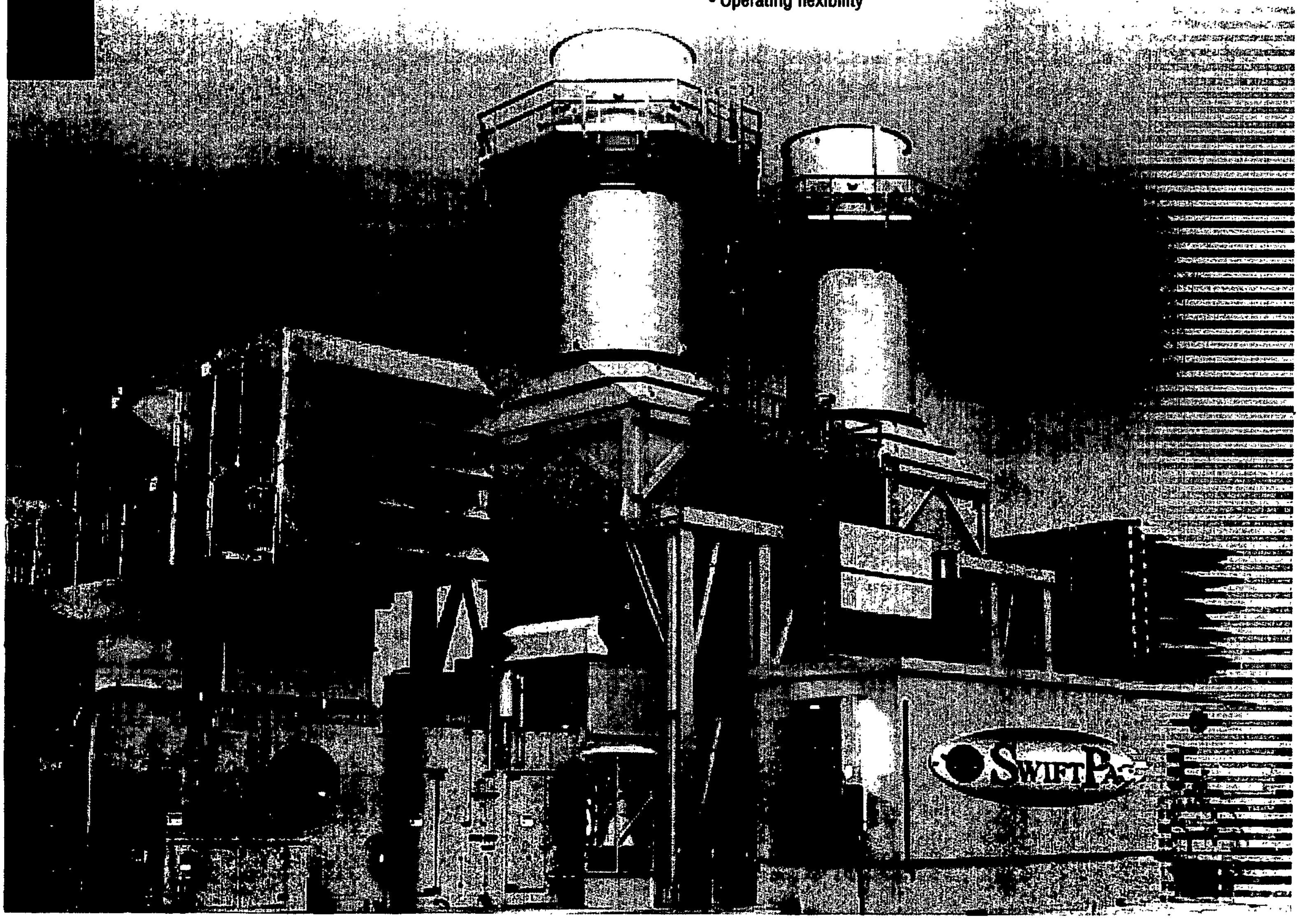
SWIFTPAC Power Plants Provide Quick, Reliable Power. Installation Takes Less Than 30 Days.

SWIFTPAC transportable power plants offer 30 or 60 MW of moveable power. Utilizing the proven Pratt & Whitney Power Systems FT8 technology, SWIFTPAC transportable power plants are designed to provide quick, reliable power. The package design includes an enclosed driver assembly incorporating the gas generator, power turbine, exhaust collector box, inlet plenum and lube system. This factory-assembled module allows the SWIFTPAC to be generating power less than 30 days after arriving on site.

Pratt & Whitney. **The Eagle is everywhere.™**

Benefits

- Best-in-class part load efficiency
- Reduced site setup time
- Lower site cost
- Less expensive shipping
- Reduced field flushing
- Minimal field wiring terminations
- Prefabricated piping needs no field welding
- Less site labor
- Standard and repeatable manufacturing process
- Standard and repeatable installation process
- Preassembled and tested
- Reduced field inventory
- **Ease of engine checkout and maintenance**
- **Operating flexibility**



FT8® SWIFTPAC® POWER PLANT

SWIFTPAC Power Plants Provide Quick, Reliable Power. Installation Takes Less Than 30 Days.

Enhancements

- Factory-assembled modules
- Integrated lube oil system
- Factory-tested quick disconnect cables
- Prefabricated field piping
- Factory-flushed lube oil systems
- Combined GT and exhaust enclosure
- Factory checkout
- Simple roadbed foundation
- Compact layout

Pratt & Whitney
A United Technologies Company

Pratt & Whitney Power Systems

1-866-POWER-ALL (1-866-769-3725)
Outside USA: 1-860-565-0140
Email: info@pw.utc.com

Visit Pratt & Whitney at www.pw.utc.com

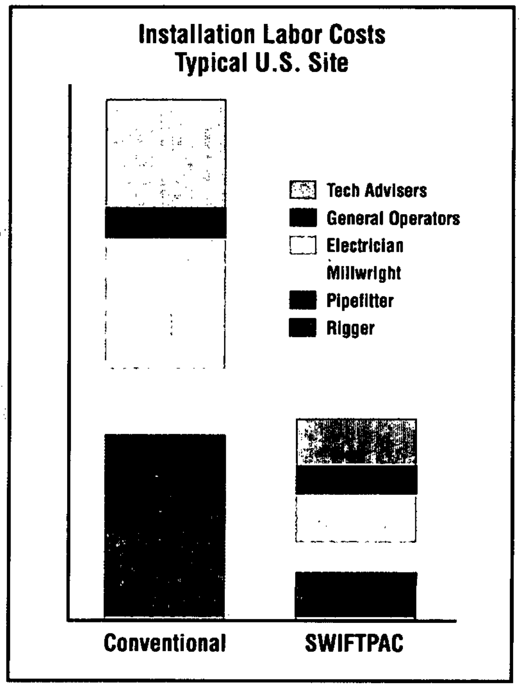
Product Facts

Simple Cycle Performance

Natural Gas

	SWIFTPAC 30	SWIFTPAC 60
Output (kW)	30446	61196
Heat Rate (BTU/kW-hr)	9312	9266
Efficiency (%)	37	37
Exhaust Flow (lb/sec)	201	402
Exhaust Temp (°F)	895	895
U.S. Transport Time	6 days	6 days
Foundation	2-3' concrete	3' concrete
Installation	3 weeks	3 weeks
NOx	25	25
Fuel	Dual	Dual
Frequency	50/60 HZ	50/60 HZ

Also available with DLN and/or inlet fogging.



rev 11.7.07

FT8-3 Swift Pac (with CO Converter)
Estimated Performance and Emissions, Part-Load Data
Tampa-Electric

Configuration: Standard NE US Gas Fuel, WI to 25 ppmvd NOx @ 15% O2,
Sea Level Alt., 55% Ambient RH, 72-290 Generator at 60 Hz, 13.8 kV, 0.85 pf Simple-Cycle

Performance Data										
Fuel Type		Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas
Percent of Swift Pac Unit Rating	%	100	75	50	100	75	50	100	75	50
Ambient Temperature	Deg F	20	20	20	59	59	59	90	90	90
Evaporative Cooler In-Service	Yes / No	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes
Chiller in Service	Yes / No	No	No	No	No	No	No	No	No	No
Compressor Inlet Temperature	Deg F	20	20	20	52	52	52	79	79	79
Ambient Pressure	Psia	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Relative Humidity	%	55	55	55	55	55	55	55	55	55
Inlet Loss	Inch H20	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Exhaust Loss	Inch H20	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Fuel Supply Temperature	Deg F	59	59	59	59	59	59	59	59	59
Fuel LHV	Btu/lb	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671
Fuel HHV	Btu/lb	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932
Ratio of HHV to LHV		1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109
Gross Power Output	MWe	62.501	46.876	31.251	62.155	46.617	31.078	57.586	43.19	28.793
Gross Heat Rate, HHV	Btu/kWhr	10,125	10,442	11,517	10,306	10,652	11,738	10,495	11,013	12,181
Power Island and Evap Aux Loads	kW	252	252	252	260	260	260	260	260	260
Net Power Output	MWe	62.249	46.624	30.999	61.895	46.357	30.818	57.326	42.930	28.533
Net Heat Rate, HHV	Btu/kWhr	10,166	10,499	11,611	10,349	10,712	11,837	10,543	11,080	12,292
Fuel Flow, per GT	lbs/hr	13,797	10,673	7,847	13,967	10,827	7,954	13,177	10,371	7,647
Burner Water Injection Flow, per GT	gal/min	29.4	20.4	13.3	31.3	21.9	14.5	29.7	21.5	14.4
EVAP Water Flow Rate, per GT	gal/min	0.0	0.0	0.0	2.3	2.1	1.8	3.4	3.1	2.6
Gaseous Fuel Flow @ 15C, per GT	SCF/hr	306,139	236,811	174,125	309,905	240,229	176,484	292,386	230,119	169,676
Emissions at GT Exit*										
NOx	ppmvd	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**
NOx, as NO2, per GT	lbs/hr	31.6	24.4	18.2	32.0	24.8	18.2	30.2	23.7	17.5
VOC as C1	ppmvd	**6.0**	**15.6**	**40.4**	**6.0**	**11.0**	**17.2**	**6.0**	**7.6**	**16.0**
VOC as C1, per GT	lbs/hr	2.6	5.3	10.1	2.7	3.8	4.3	2.5	2.5	3.9
SO2	ppmvd	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
SO2, per GT	lbs/hr	0.48	0.37	0.27	0.49	0.38	0.28	0.46	0.36	0.27
TSP/PM10, Filterable and Cond, per GT	lbs/hr	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**
Exhaust Gas Flow, per GT **	lbs/sec	212	190	161	204	182	153	192	169	143
Exhaust Gas Temperature **	Deg F	828	748	701	893	817	767	917	864	814
Exhaust Gas Molecular Weight, Wet		28.23	28.36	28.46	28.08	28.21	28.31	27.89	28.00	28.10
Exhaust Gas Vol Flow Rate, per GT **	ACFS	7,058	5,910	4,783	7,166	6,000	4,847	6,917	5,843	4,734
Stack Exhaust Velocity, per GT **	ft/s	99.6	83.4	67.5	101.1	84.6	68.4	97.6	82.4	66.8
H2O	% Vol wet	9.25	7.76	6.57	10.77	9.29	8.05	12.45	11.24	10.00
O2	% Vol wet	13.5	14.6	15.4	12.9	14.0	14.9	12.6	13.5	14.4
CO2	% Vol wet	3.14	2.72	2.38	3.29	2.88	2.52	3.27	2.93	2.57
A	% Vol wet	0.871	0.881	0.889	0.858	0.868	0.877	0.842	0.851	0.859
N2	% Vol wet	73.2	74.1	74.7	72.1	73.0	73.7	70.8	71.5	72.2
Treated Exhaust Characteristics (Post CO Converter)*										
CO		**8.0**	**14.1**	**20.9**	**6.0**	**11.6**	**14.8**	**6.0**	**9.3**	**14.3**
CO, per GT		6.2	8.4	9.1	4.7	7.0	6.6	4.4	5.4	6.1

Notes:
* All ppmvd corrected to 15% O2
** Secondary Cooling Air Separately Exhausted

Guaranteed values are indicated by (G), or $\boxed{\textbf{value}}$
All other data are estimates.

Source: PWPS, 2008.

FT8-3 Swift Pac (with CO Converter)
Estimated Performance and Emissions, Part-Load Data
Tampa-Electric

Configuration: Specified Liquid Fuel (ULSD), WI to 42 ppmvd NOx @ 15% O2,
Sea Level Alt., 55% Ambient RH, 72-290 Generator at 60 Hz, 13.8 kV, 0.85 pf Simple-Cycle

Performance Data										
Fuel Type		Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid
Percent of Swift Pac Unit Rating	%	100	75	50	100	75	50	100	75	50
Ambient Temperature	Deg F	20	20	20	59	59	59	90	90	90
Evaporative Cooler In-Service	Yes / No	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes
Chiller in Service	Yes / No	No	No	No	No	No	No	No	No	No
Compressor Inlet Temperature	Deg F	20	20	20	52	52	52	79	79	79
Ambient Pressure	Psia	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Relative Humidity	%	55	55	55	55	55	55	55	55	55
Inlet Loss	Inch H20	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Exhaust Loss	Inch H20	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Fuel Supply Temperature	Deg F	127	127	127	127	127	127	127	127	127
Fuel LHV	Btu/lb	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360
Fuel HHV	Btu/lb	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553
Ratio of HHV to LHV		1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065
Gross Power Output	MWe	56.065	42.049	28.033	56.167	42.125	28.084	56.02	42.015	28.01
Gross Heat Rate, HHV	Btu/kWhr	9,877	10,396	11,533	10,075	10,592	11,739	10,263	10,797	11,950
Power Island and Evap Aux Loads	kW	277	277	277	285	285	285	285	285	285
Net Power Output	MWe	55.788	41.772	27.756	55.882	41.84	27.799	55.735	41.73	27.725
Net Heat Rate, HHV	Btu/kWhr	9,926	10,465	11,648	10,126	10,665	11,860	10,315	10,870	12,073
Fuel Flow, per GT	lbs/hr	14,159	11,178	8,267	14,470	11,409	8,430	14,701	11,599	8,559
Burner Water Injection Flow, per GT	gal/min	29.6	21.1	13.7	32.2	23.1	15.1	34.3	24.8	16.3
EVAP Water Flow Rate, per GT	gal/min	0.0	0.0	0.0	2.3	2.0	1.7	3.4	3.0	2.6
Gaseous Fuel Flow @ 15C, per GT	SCF/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Emissions at GT Exit*										
NOx	ppmvd	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**
NOx, as NO2, per GT	lbs/hr	49.4	38.9	28.7	50.5	39.8	29.3	51.3	40.4	29.8
VOC as C1	ppmvd	**5.0**	**8.7**	**25.4**	**5.0**	**5.0**	**13.1**	**5.0**	**5.0**	**7.8**
VOC as C1, per GT	lbs/hr	2.0	2.8	6.0	2.1	1.6	3.2	2.1	1.7	1.9
SO2	ppmvd	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
SO2, per GT	lbs/hr	0.47	0.37	0.27	0.48	0.38	0.28	0.49	0.38	0.28
TSP/PM10, Filterable and Cond, per GT	lbs/hr	**7.5**	**7.5**	**7.5**	**7.5**	**7.5**	**7.5**	**7.5**	**7.5**	**7.5**
Exhaust Gas Flow, per GT **	lbs/sec	205	182	154	197	174	147	190	168	142
Exhaust Gas Temperature **	Deg F	793	744	699	864	814	767	921	872	823
Exhaust Gas Molecular Weight, Wet		28.64	28.70	28.76	28.49	28.56	28.63	28.27	28.34	28.41
Exhaust Gas Vol Flow Rate, per GT **	ACFS	6,558	5,567	4,534	6,688	5,669	4,610	6,788	5,750	4,669
Stack Exhaust Velocity, per GT **	ft/s	92.5	78.5	64.0	94.4	80.0	65.0	95.8	81.1	65.9
H2O	% Vol wet	6.85	5.86	4.88	8.41	7.37	6.31	10.63	9.57	8.45
O2	% Vol wet	14.2	14.9	15.7	13.5	14.3	15.2	12.8	13.6	14.5
CO2	% Vol wet	4.00	3.58	3.13	4.23	3.79	3.32	4.42	3.97	3.48
A	% Vol wet	0.882	0.889	0.897	0.868	0.876	0.884	0.849	0.857	0.865
N2	% Vol wet	74.1	74.7	75.3	73.0	73.6	74.3	71.3	72.0	72.7
Treated Exhaust Characteristics (Post CO Converter)*										
CO		**2.1**	**3.2**	**5.1**	**2.0**	**2.3**	**3.8**	**2.0**	**2.0**	**3.8**
CO, per GT		1.5	1.8	2.1	1.5	1.4	1.6	1.5	1.2	0.6

Notes:
* All ppmvd corrected to 15% O2
** Secondary Cooling Air Separately Exhausted

Guaranteed values are indicated by (G), or **value**
All other data are estimates.

Source: PWPS, 2008.

ATTACHMENT 3

RESPONSE TO EPC-3

EXPLANATION OF APPENDIX B
EMISSION RATE CALCULATIONS

TEC BIG BEND STATION
SIMPLE CYCLE COMBUSTION TURBINES UNIT 4
EXPLANATION OF APPENDIX B EMISSION RATE CALCULATIONS

Emissions data for the Pratt & Whitney Power Systems (PWPS) FT8-3 SWIFTPAC simple cycle combustion turbines (SCCTs) are provided in Appendix B of the permit application, Tables B-1 through B-20. The following sections provide the basis for each emission rate calculation.

Note that the calculation results provided in Tables B-1 through B-20 used the full electronic spreadsheet precision; i.e., were not rounded. For this reason, a check of the calculations using the data shown in Tables B-1 through B-20 may, in some cases, produce slightly different results because the tables do not display all of the 15 digits used by the electronic spreadsheet.

Table B-1: SCCT Annual Emission Rate Summary

The criteria pollutant emissions on this table are taken directly from Tables B-10 and B-11 for the SCCTs, and from Table B-16 for the emergency engine. HAPs are shown for the SCCTs only, and were taken from Table B-9. The H_2SO_4 mist emission rate is also taken from Tables B-10 and B-11 for the SCCTs. CO_2 emission rates, based on emission factors, heat input rates, and operating hours, were calculated as shown below. Annual emission rates for the SCCTs represent the maximum values from Table B-10 (Annual Profile #1 - 3,500 hrs/yr natural gas) and Table B-11 (Annual Profile #2 - 3,000 hrs/yr natural gas and 500 hrs/yr ULSD fuel oil).

CO_2 Calculation for the SCCTs:

AP-42 CO_2 Emission Factor (Natural Gas) = 110 lb/MMBtu (from AP-42 Table 3.1-2a)

AP-42 CO_2 Emission Factor (ULSD Fuel Oil) = 157 lb/MMBtu (from AP-42 Table 3.1-2a)

Heat Input per SCCT (Natural Gas) = 342.7 MMBtu/hr (from Table B-13, Case 4)

Heat Input per SCCT (ULSD Fuel Oil) = 302.7 MMBtu/hr (from Table B-15, Case 4)

Annual Operating Hours = 3,000 hrs/yr (natural gas and 500 hrs/yr ULSD fuel oil
(From Table B-2, Annual Profile #2)

CO_2 = [(110 lb/MMBtu x 342.7 MMBtu/hr x 3,000 hr/yr) +
(157 lb/MMBtu x 302.7 MMBtu/hr x 500 hr/yr)] x (1 ton /2,000 lb)
x 2 SCCTs = 136,865 ton/yr

CO_2 Calculation for the Emergency Engine:

AP-42 CO_2 Emission Factor = 165 lb/MMBtu (from AP-42 Table 3.4-1)

Heat Input per Engine = 7.89 MMBtu/hr (from Table B-17)

Annual Operating Hours = 100 hours per year (from Table B-17)

CO_2 = 165 lb/MMBtu x 7.89 MMBtu/hr x 100 hr/yr x ton/2,000 lb x 1 engine = 65 ton/yr

Table B-2: SCCT Operating Scenarios

Operating scenarios identified in Table B-2 represent the range of loads (50 to 100 percent), approximate ambient temperatures (20 to 90°F), fuel types (natural gas and ULSD fuel oil), and use of evaporative cooling under which Unit 4 will operate.

TEC BIG BEND STATION
SIMPLE CYCLE COMBUSTION TURBINES UNIT 4
EXPLANATION OF APPENDIX B EMISSION RATE CALCULATIONS

Table B-3: Hourly PM/PM$_{10}$, SO$_2$, H$_2$SO$_4$ Mist, and Pb Emission Rates (per SCCT) - Natural Gas

A. PM/PM$_{10}$

For each ambient temperature and SCCT operating load, PM/PM$_{10}$ emissions in lb/hr were based on PWPS data for PM/PM$_{10}$ as measured by EPA Reference Methods 201 or 201A, and 202. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 2; 20°F ambient temperature, 75% load

PWPS PM/PM$_{10}$ = 2.5 lb/hr

PM/PM$_{10}$ = 2.5 lb/hr x 0.126 = 0.32 g/s

B. SO$_2$

For each ambient temperature and SCCT operating load, SO$_2$ emissions in lb/hr were based on PWPS fuel flow data, natural gas sulfur content of 2.0 gr S/100 ft^3, natural gas density of 0.0451 lb/ft^3, and conversion factor of 7,000 grains per pound. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 4; 59°F ambient temperature, 100% load

Fuel Flow = 13,967 lb/hr NG

Margin = 7%

Adjusted Fuel Flow = Fuel Flow x Margin = 13,967 lb/hr x 1.07 =14,945 lb/hr

SO$_2$ = (14,945 lb/hr NG) x (2.0 gr S / 100 ft^3) x (ft^3 / 0.0451 lb NG)

x (1 lb S / 7,000 gr S) x (2 lb SO$_2$ / 1 lb S)

SO$_2$ = 1.89 lb/hr

SO$_2$ = 1.89 lb/hr x 0.126 = 0.24 g/s

C. H$_2$SO$_4$

For each ambient temperature and SCCT operating load, H$_2$SO$_4$ emissions in lb/hr were based on an assumed 7.5% conversion rate by volume of SO$_2$ to H$_2$SO$_4$. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 7; 90°F ambient temperature, 100% load

SO$_2$ = 1.79 lb/hr

H$_2$SO$_4$ = (1.79 lb/hr SO$_2$) x (7.5 / 100) x (98 lb-mole H$_2$SO$_4$ / 64 lb-mole SO$_2$)

H$_2$SO$_4$ = 0.21 lb/hr

H$_2$SO$_4$ = 0.21 lb/hr x 0.126 = 0.026 g/s

TEC BIG BEND STATION
SIMPLE CYCLE COMBUSTION TURBINES UNIT 4
EXPLANATION OF APPENDIX B EMISSION RATE CALCULATIONS

D. Lead

For each ambient temperature and SCCT operating load, estimates of lead emission rates were developed using an emission factor from EPA AP-42 (Section 1.4 Natural Gas Combustion, Table 1.4-2), and PWPS heat input rates.

Example: Case 1; 20°F ambient temperature, 100% load

PWPS Fuel Flow = 14,763 lb/hr (with margin)

Heat Input = 14,763 lb/hr x 22,933 Btu/lb [HHV] = 338.6 x 10^6 Btu/hr [HHV]

Lead Emission Factor = 4.9 x 10^{-7} lb / 10^6 Btu

Lead = (338.6 x 10^6 Btu/hr) x (4.9 x 10^{-7} lb / 10^6 Btu)

Lead = 0.00017 lb/hr (Negligible)

Table B- 4: NO_x, CO, and CO Emission Rates (per SCCT) - Natural Gas

A. NO_x

For each ambient temperature and SCCT operating load, NO_x emissions in ppmvd at 15% O_2 and lb/hr were based on PWPS data. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 3; 20°F ambient temperature, 50% load

PWPS NO_x = 25 ppmvd @ 15% O_2 PWPS NO_x = 18.2 lb/hr

NO_x = 18.2 lb/hr

NO_x = 18.2 lb/hr x 0.126 = 2.29 g/s

B. CO

For each ambient temperature and SCCT operating load, CO emissions in ppmvd at 15% O_2 and lb/hr were based on PWPS data. The efficiency of the oxidation catalyst was used to determine the final emissions in the exhaust. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 7; 90°F ambient temperature, 100% load

PWPS CO = 60 ppmvd @ 15% O_2 PWPS CO = 44.1 lb/hr

Oxidation Catalyst Efficiency = 90%

CO = 44.1 lb/hr x (100-90)/100 = 4.4 lb/hr

CO = 4.4 lb/hr x 0.126 = 0.55 g/s

C. VOC

For each ambient temperature and SCCT operating load, VOC emissions in ppmvd at 15% O_2 and lb/hr were based on PWPS data. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 5; 59°F ambient temperature, 75% load

PWPS VOC = 11.1 ppmvd @ 15% O_2 PWPS VOC = 3.8 lb/hr

Oxidation Catalyst Efficiency = 50%

VOC = 3.8 lb/hr x (100-50)/100 = 1.9 lb/hr

VOC = 1.9 lb/hr x 0.126 = 0.24 g/s

Table B-5: Hazardous Air Pollutant Hourly Emission Rates (Per SCCT) - Natural Gas

Estimates of hazardous air pollutant emission rates were developed using emission factors from the references shown at the bottom of Table B-5 and PWPS heat input data for each operating case. As indicated in the second footnote of the table, the emission factors for the organic compounds have been adjusted to account for the control efficiency of the oxidation catalyst. The maximum hourly heat input rate occurs at 59°F ambient temperature, 100% load i.e., Case 4. For annual emission estimates, maximum values from Table B-9 were used.

Example: Maximum Hourly Naphthalene; Case 1; 20°F ambient temperature, 100% load

PWPS SCCT Heat Input = 338.6 x 10^6 Btu/hr [HHV] (with margin)

Naphthalene AP-42 Emission Factor = 1.30 x 10^{-6} lb / 10^6 Btu

Since naphthalene is an organic, the emission factor is adjusted to account for 50% control efficiency.

Adjusted Emission Factor = 1.30 x 10^{-6} lb / 10^6 Btu x 0.5 = 6.50 x 10^{-7} lb / 10^6 Btu

Naphthalene = (338.6 x 10^6 Btu/hr) x (6.50 x 10^{-7} lb / 10^6 Btu)

Naphthalene = 2.20 x 10^{-4} lb/hr

Table B-6: Hourly PM/PM_{10}, SO_2, H_2SO_4 Mist, and Pb Emission Rates (per SCCT) –ULSD Fuel Oil

A. PM/PM_{10}

For each ambient temperature and SCCT operating load, PM/PM_{10} emissions in lb/hr were based on PWPS data for PM/PM_{10} as measured by EPA Reference Methods 201 or 201A, and 202. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

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Example: Case 2; 20°F ambient temperature, 75% load

PWPS PM/PM_{10} = 7.5 lb/hr

PM/PM_{10} = 7.5 lb/hr x 0.126 = 0.95 g/s

B. SO_2

For each ambient temperature and SCCT operating load, SO_2 emissions in lb/hr were based on PWPS ULSD fuel oil flow data and sulfur content of 0.0015 weight percent. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 4; 59°F ambient temperature, 100% load

Fuel Flow = 14,470 lb/hr ULSD fuel oil

Margin = 7%

Adjusted Fuel Flow = Fuel Flow x Margin = 14,470 lb/hr x 1.07 =15,483 lb/hr

SO_2 = (15,483 lb/hr ULSD) x (0.0015 lb S / 100 lb ULSD) x (2 lb SO_2 / 1 lb S)

SO_2 = 0.46 lb/hr

SO_2 = 0.46 lb/hr x 0.126 = 0.06 g/s

C. H_2SO_4

For each ambient temperature and SCCT operating load, H_2SO_4 emissions in lb/hr were based on an assumed 7.5% conversion rate by volume of SO_2 to H_2SO_4. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 7; 90°F ambient temperature, 100% load

SO_2 = 0.47 lb/hr

H_2SO_4 = (0.47 lb/hr SO_2) x (7.5 / 100) x (98 lb-mole H_2SO_4 / 64 lb-mole SO_2)

H_2SO_4 = 0.054 lb/hr

H_2SO_4 = 0.054 lb/hr x 0.126 = 0.0068 g/s

D. Lead

For each ambient temperature and SCCT operating load, estimates of lead emission rates were developed using the ULSD Pb emission factor from Table B-8 and PWPS heat input rates.

Example: Case 1; 20°F ambient temperature, 100% load

PWPS Fuel Flow = 15,150 lb/hr (with margin)

Heat Input = 15,150 lb/hr x 19,553 Btu/lb [HHV] = 296.2 x 10^6 Btu/hr [HHV]

Lead Emission Factor = 7.67 x 10^{-7} lb / 10^6 Btu

Lead = (296.2 x 10^6 Btu/hr) x (7.67 x 10^{-7} lb / 10^6 Btu)

Lead = 0.00023 lb/hr (Negligible)

Table B- 7: NO_x, CO, and CO Emission Rates (per SCCT) – ULSD Fuel Oil

A. NO_x

For each ambient temperature and SCCT operating load, NO_x emissions in ppmvd at 15% O_2 and lb/hr were based on PWPS data. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 3; 20°F ambient temperature, 50% load

PWPS NO_x = 42 ppmvd @ 15% O_2 PWPS NO_x = 28.7 lb/hr

NO_x = 28.7 lb/hr

NO_x = 28.7 lb/hr x 0.126 = 3.62 g/s

B. CO

For each ambient temperature and SCCT operating load, CO emissions in ppmvd at 15% O_2 and lb/hr were based on PWPS data. The efficiency of the oxidation catalyst was used to determine the final emissions in the exhaust. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 7; 90°F ambient temperature, 100% load

PWPS CO = 20 ppmvd @ 15% O_2 PWPS CO = 15.0 lb/hr

Oxidation Catalyst Efficiency = 90%

CO = 15.0 lb/hr x (100-90)/100 = 1.5 lb/hr

CO = 1.5 lb/hr x 0.126 = 0.19 g/s

C. VOC

For each ambient temperature and SCCT operating load, VOC emissions in ppmvd at 15% O_2 and lb/hr were based on PWPS data. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 5; 59°F ambient temperature, 75% load

PWPS VOC = 5.0 ppmvd @ 15% O_2 PWPS VOC = 1.6 lb/hr

Oxidation Catalyst Efficiency = 50%

VOC = 1.6 lb/hr x (100-50)/100 = 0.8 lb/hr

VOC = 0.8 lb/hr x 0.126 = 0.10 g/s

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Table B-8: Hazardous Air Pollutant Hourly Emission Rates (Per SCCT) – ULSD Fuel Oil

Estimates of hazardous air pollutant emission rates were developed using emission factors from the references shown at the bottom of Table B-8 and PWPS heat input data for all operating cases. As indicated in the third footnote of the table, the emission factors for the organic compounds have been adjusted to account for the control efficiency of the oxidation catalyst. The maximum hourly heat input rate occurs at 90°F ambient temperature, 100% load i.e., Case 7. For annual emission estimates, maximum values from Table B-9 were used.

Example: Maximum Hourly Naphthalene; Case 7; 90°F ambient temperature, 100% load

PWPS SCCT Heat Input = 307.6 x 10^6 Btu/hr [HHV] (with margin)

Naphthalene AP-42 Emission Factor = 3.50 x 10^{-5} lb / 10^6 Btu

Since naphthalene is an organic, the emission factor is adjusted to account for 50% control efficiency.

Adjusted Emission Factor = 3.50 x 10^{-5} lb / 10^6 Btu x 0.5 = 1.75 x 10^{-5} lb / 10^6 Btu

Naphthalene = (307.6 x 10^6 Btu/hr) x (1.75 x 10^{-5} lb / 10^6 Btu)

Naphthalene = 5.38 x 10^{-3} lb/hr

Table B-9: Hazardous Air Pollutant Annual Emission Rates (2 SCCTs)

Annual hazardous air pollutant emission rates were determined based on the maximum pollutant hourly rates contained in Tables B-5 and B-8 for Case 4 (i.e., 59°F, 100% SCCT load) for Annual Profile #1 (3,500 hrs/yr natural gas) and Annual Profile #2 (3,000 hrs/yr natural gas and 500 hrs/yr ULSD fuel oil).

Example: Annual Profile #2

Natural Gas:

Naphthalene = (2.23 x 10^{-4} lb/hr) x (3,000 hr/yr) x (ton / 2,000 lb) x 2 SCCTs

Naphthalene = 6.68 x 10^{-4} ton/yr

ULSD Fuel Oil:

Naphthalene = (5.30 x 10^{-3} lb/hr) x (500 hr/yr) x (ton / 2,000 lb) x 2 SCCTs

Naphthalene = 2.65 x 10^{-3} ton/yr

Total Natural Gas + ULSD Fuel Oil

Naphthalene = 6.68 x 10^{-4} ton/yr + 2.65 x 10^{-3} ton/yr

Naphthalene = 3.32 x 10^{-3} ton/yr

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TableB-10: Annual Criteria and Sulfuric Acid Mist Pollutant Emission Rates – Annual Profile #1

Annual emission rates were determined from the pollutant hourly rates for Case 4 (59°F, 100% SCCT load, and assuming that each SCCT operates for 3,500 hours per year on natural gas. An example calculation for NO_x follows:

Example: NO_x

Case 4 NO_x Hourly Emission Rate = 32.0 lb/hr (per SCCT)

Annual NO_x = 32.0 lb/hr x 3,500 hrs/yr x ton/ 2000 lb x 2 SCCTs

Annual NO_x = 112.0 ton/yr

TableB-11: Annual Criteria and Sulfuric Acid Mist Pollutant Emission Rates – Annual Profile #2

Annual emission rates were determined from the pollutant hourly rates for Case 4 (59°F, 100% SCCT load, and assuming that each SCCT operates for 3,000 hours per year on natural gas and 500 hours per year on ULSD fuel oil. An example calculation for NO_x follows:

Example: NO_x

Natural Gas:

Case 4 NO_x Hourly Emission Rate = 32.0 lb/hr (per SCCT)

Annual NO_x = 32.0 lb/hr x 3,000 hrs/yr x ton/ 2000 lb x 2 SCCTs

Annual NO_x = 96.0 ton/yr

ULSD Fuel Oil:

Case 4 NO_x Hourly Emission Rate = 50.5 lb/hr (per SCCT)

Annual NO_x = 50.5 lb/hr x 500 hrs/yr x ton/ 2000 lb x 2 SCCTs

Annual NO_x = 25.7 ton/yr

Total Natural Gas + ULSD Fuel Oil

Annual NO_x = 96.0 ton/yr + 25.7 ton/yr

Annual NO_x = 121.7 ton/yr

Table B-12: SCCT Exhaust Data (Per SCCT), Natural Gas

Table B-12A.: Exhaust Molecular Weight (MW)

Exhaust gas compositions (volume %), exhaust flow rates (lb/sec), and exhaust temperatures (°F) shown in Table B-12A were obtained from the PWPS performance specification data.

1. Exhaust gas molecular weight was calculated by multiplying the exhaust composition (in volume % divided by 100) by the component molecular weight (in lb/lb-mole) and summing all components.

Example: Case 7 (90°F, 100% Load)

MW = [(0.842/100) x 39.944] + [(70.8/100) x 28.013] + [(12.6/100) x 31.999] + [(3.27/100) x 44.010] + [(12.45/100) x 18.015]

MW = 27.88 lb/lb-mole

2. Exhaust temperatures (in units of °K) were calculated by converting the PWPS exhaust temperatures (in units of °F)

Example: Case 8 (90°F, 75% Load)

PWPS Exhaust Temperature: 864 °F

Exhaust Temperature = (864 °F + 459.67) / (1.8)

Exhaust Temperature = 735 °K

3. Exhaust oxygen concentrations, dry were calculated by correcting the PWPS exhaust oxygen concentrations, wet, to dry conditions.

Example: Case 6 (59°F, 50% Load)

PWPS Exhaust Oxygen Concentration: 14.9 volume % (wet)

PWPS Exhaust Water Concentration: 8.05 volume %

Exhaust Oxygen Concentration (dry) = [(14.9) / (100 – 8.05)] x 100

Exhaust Oxygen Concentration = 16.20 volume % (dry)

Table B-12B.: Exhaust Flow Rates Data

Exhaust gas flow rates (actual, standard, and actual at 15% O_2, dry) were calculated based on the PWPS data shown in Table B12A. Stack diameter was provided by TEC. Stack exit velocity was calculated based on the exhaust flow rates and calculated stack area.

1. Exhaust gas flow rates, in units of actual cubic feet per minute, were calculated based on the PWPS exhaust flow rates (in units of lb/sec) and molecular weights shown in Table B-12A and the Ideal Gas Law.

Example: Case 1 (20°F, 100% Load)

PWPS Exhaust Flow Rate: 212.0 lb/sec (from Table B-12A)

Exhaust Gas Molecular Weight: 28.22 lb/lb-mole (from Table B-12A)

PWPS Exhaust Gas Temperature: 828 °F (from Table B-12A)

Volume of one lb-mole at 68°F: 385.3 ft^3/lb-mole (Ideal Gas Law)

Exhaust Gas Flow Rate (acfm) = (212.0 lb/sec) x (60 sec/min) x (lb-mole / 28.22 lb) x (385.3 ft^3/lb-mole) x [(828 + 460) / (68 + 460)]

Exhaust Gas Flow Rate = 423,625 acfm

2. Stack area was calculated based on the stack exit diameter provided by TEC.

Example: All Cases

Stack Exit Diameter: 9.5 ft; 2.896 m

Stack Exit Area = π x (9.5 ft / 2)^2

Stack Exit Area = 70.88 ft^2; 6.59 m^2

3. Stack exit velocities were calculated by dividing the calculated actual exhaust flow rate by the stack exit area.

Example: Case 3 (20°F, 50% Load)

Calculated Actual Exhaust Flow Rate: 287,770 ft^3/min (From Table B-12B)

Calculated Stack Exit Area: 70.88 ft^2

Stack Exit Velocity = (287,770 ft^3/min) x (1 min / 60 sec) x (1 / 70.88 ft^2)

Stack Exit Velocity = 67.7 ft/sec; 20.6 m/sec

4. Exhaust gas flow rates, in units of dry, standard (at 68 °F) actual cubic feet per minute, were calculated based on the PWPS exhaust flow rates (in units of lb/sec), moisture contents, and molecular weights shown in Table B-12A and the Ideal Gas Law.

Example: Case 7 (90°F, 100% Load)

PWPS Exhaust Flow Rate: 192.0 lb/sec (from Table B-12A)

PWPS Exhaust Gas Moisture Content: 12.45 volume % (from Table B-12A)

Exhaust Gas Molecular Weight: 27.88 lb/lb-mole (From Table B-12A)

Volume of One lb-mole at 68°F: 385.3 ft^3/lb-mole (Ideal Gas Law)

Exhaust Gas Flow Rate (dscfm) = (192.0 lb/sec) x (60 sec / min) x (lb-mole / 27.88 lb) x (385.3 ft^3/lb-mole) x [1 - (12.45 / 100)]

Exhaust Gas Flow Rate = 139,366 dscfm

5 Exhaust gas flow rates, in units of dry, standard cubic feet per minute corrected to 15% O_2, were calculated by correcting the standard dry exhaust flow rate (dscfm) to 15% O_2.

Example: Case 9 (90°F, 50% Load)

Exhaust Flow Rate: 105,847 dscfm (from Table B-12B)

Calculated Exhaust Oxygen Content: 16.0 volume % (dry) (from Table B-12A)

Atmospheric Oxygen Content: 20.9 volume %

Exhaust Gas Flow Rate (dscfm @ 15% O_2) = (105,847 dscfm) x [(20.9 – 16.0) / (20.9 – 15.0)]

Exhaust Gas Flow Rate = 87,907 dscfm @ 15% O_2

Table B-13: Fuel Flow Rate Data (Per SCCT) - Natural Gas

Data shown in Table B-13 is based on PWPS fuel flow rates, and the heat content and density of natural gas. The PWPS fuel rate (lb/hr) as shown on the table has been adjusted to include a 7 % margin. The heat input values and conversions to other fuel rate units have been derived from the adjusted PWPS fuel rate.

Example: Case 5 (59°F, 75% load)

PWPS fuel rate = 10,827 lb/hr

Adjusted fuel rate = 10,827 lb/hr x 1.07 = 11,585 lb/hr

Natural Gas Density = 0.0451 lb/ft^3

Natural Gas Heat Content: 20,671 Btu/lb (LHV)

Natural Gas Heat Content: 22,933 Btu/lb (HHV)

Heat Input (LHV) = 11,585 lb/hr x 20,671 Btu/lb x ($1/10^6$) = 239.5 MMBtu/hr

Heat Input (HHV) = 11,585 lb/hr x 22,933 Btu/lb x ($1/10^6$) = 265.7 MMBtu/hr

Fuel Rate = 11,585 lb/hr / 0.0451 lb/ft^3 x ($1/10^6$) = 0.257 10^6 ft^3/hr

Fuel Rate = 11,585 lb/hr x hr/3,600 sec = 3.218 lb/sec

Table B-14: SCCT Exhaust Data (Per SCCT), ULSD Fuel Oil

Table B-14A.: Exhaust Molecular Weight (MW)

Exhaust gas compositions (volume %), exhaust flow rates (lb/sec), and exhaust temperatures (°F) shown in Table B-14A were obtained from the PWPS performance specification data.

1. Exhaust gas molecular weight was calculated by multiplying the exhaust composition (in volume % divided by 100) by the component molecular weight (in lb/lb-mole) and summing all components.

Example: Case 8 (90°F, 75% Load)

MW = [(0.857/100) x 39.944] + [(72.0/100) x 28.013] + [(13.6/100) x 31.999]
+ [(3.97/100) x 44.010] + [(9.57/100) x 18.015]

MW = 28.34 lb/lb-mole

2. Exhaust temperatures (in units of °K) were calculated by converting the PWPS exhaust temperatures (in units of °F)

Example: Case 8 (90°F, 75% Load)

PWPS Exhaust Temperature: 872 °F

Exhaust Temperature = (872 °F + 459.67) / (1.8)

Exhaust Temperature = 740 °K

3. Exhaust oxygen concentrations, dry were calculated by correcting the PWPS exhaust oxygen concentrations, wet, to dry conditions.

Example: Case 6 (59°F, 50% Load)

PWPS Exhaust Oxygen Concentration: 15.2 volume % (wet)

PWPS Exhaust Water Concentration: 6.31 volume %

Exhaust Oxygen Concentration (dry) = [(15.2) / (100 – 6.31)] x 100

Exhaust Oxygen Concentration = 16.22 volume % (dry)

Table B-14B.: Exhaust Flow Rates Data

Exhaust gas flow rates (actual, standard, and actual at 15% O_2, dry) were calculated based on the PWPS data shown in Table B14A. Stack diameter was provided by TEC. Stack exit velocity was calculated based on the exhaust flow rates and calculated stack area.

1. Exhaust gas flow rates, in units of actual cubic feet per minute, were calculated based on the PWPS exhaust flow rates (in units of lb/sec) and molecular weights shown in Table B-14A and the Ideal Gas Law.

Example: Case 1 (20°F, 100% Load)

PWPS Exhaust Flow Rate: 205.0 lb/sec (from Table B-14A)

Exhaust Gas Molecular Weight: 28.65 lb/lb-mole (from Table B-14A)

PWPS Exhaust Gas Temperature: 793 °F (from Table B-14A)

Volume of one lb-mole at 68°F: 385.3 ft^3/lb-mole (Ideal Gas Law)

Exhaust Gas Flow Rate (acfm) = (205.0 lb/sec) x (60 sec/min) x (lb-mole / 28.65 lb) x (385.3 ft^3/lb-mole) x [(793 + 460) / (68 + 460)]

Exhaust Gas Flow Rate = 392,572 acfm

2. Stack area was calculated based on the stack exit diameter provided by TEC.

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Example: All Cases

Stack Exit Diameter: 9.5 ft; 2.896 m

Stack Exit Area = π x (9.5 ft / 2)^2

Stack Exit Area = 70.88 ft^2; 6.59 m^2

3. Stack exit velocities were calculated by dividing the calculated actual exhaust flow rate by the stack exit area.

Example: Case 3 (20°F, 50% Load)

Calculated Actual Exhaust Flow Rate: 271,983 ft^3/min (From Table B-14B)

Calculated Stack Exit Area: 70.88 ft^2

Stack Exit Velocity = (271,983 ft^3/min) x (1 min / 60 sec) x (1 / 70.88 ft^2)

Stack Exit Velocity = 64.0 ft/sec; 19.5 m/sec

4. Exhaust gas flow rates, in units of dry, standard (at 68 °F) actual cubic feet per minute, were calculated based on the PWPS exhaust flow rates (in units of lb/sec), moisture contents, and molecular weights shown in Table B-14A and the Ideal Gas Law.

Example: Case 7 (90°F, 100% Load)

PWPS Exhaust Flow Rate: 190.0 lb/sec (from Table B-14A)

PWPS Exhaust Gas Moisture Content: 10.63 volume % (from Table B-14A)

Exhaust Gas Molecular Weight: 28.27 lb/lb-mole (From Table B-14A)

Volume of One lb-mole at 68°F: 385.3 ft^3/lb-mole (Ideal Gas Law)

Exhaust Gas Flow Rate (dscfm) = (190.0 lb/sec) x (60 sec / min) x (lb-mole / 28.27 lb)
x (385.3 ft^3/lb-mole) x [1 - (10.63 / 100)]

Exhaust Gas Flow Rate = 138,864 dscfm

5 Exhaust gas flow rates, in units of dry, standard cubic feet per minute corrected to 15% O_2, were calculated by correcting the standard dry exhaust flow rate (dscfm) to 15% O_2.

Example: Case 9 (90°F, 50% Load)

Exhaust Flow Rate: 105,804 dscfm (from Table B-14B)

Calculated Exhaust Oxygen Content: 15.84 volume % (dry) (from Table B-14A)

Atmospheric Oxygen Content: 20.9 volume %

Exhaust Gas Flow Rate (dscfm @ 15% O_2) = (105,804 dscfm) x [(20.9 – 15.84) / (20.9 – 15.0)]

Exhaust Gas Flow Rate = 90,770 dscfm @ 15% O_2

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Table B-15 Fuel Flow Rate Data (Per SCCT) – ULSD Fuel Oil

Data shown in Table B-15 is based on PWPS ULSD fuel flow rates and ULSD heat content and density. The PWPS fuel rate (lb/hr) as shown on the table has been adjusted to include a 7 % margin. The heat input values and conversions to other fuel rate units have been derived from the adjusted PWPS fuel rate.

Example: Case 5 (59°F, 75% load)

PWPS fuel rate = 11,409 lb/hr

Adjusted fuel rate = 11,409 lb/hr x 1.07 = 12,208 lb/hr

ULSD Fuel Oil Heat Content: 18,360 Btu/lb (LHV)

ULSD Fuel Oil Heat Content: 19,553 Btu/lb (HHV)

ULSD Fuel Oil Density: 6.81 lb/gal

Heat Input (LHV) = 12,208 lb/hr x 18,360 Btu/lb x $(1/10^6)$ = 224.1 MMBtu/hr

Heat Input (HHV) = 12,208 lb/hr x 19,553 Btu/lb x $(1/10^6)$ = 238.7 MMBtu/hr

Fuel Rate = 12,208 lb/hr / 6.81 lb/gal x $(1/10^3)$ = 1.793 10^3 gal/hr

Fuel Rate = 12,208 lb/hr x hr/3,600 sec = 3.391 lb/sec

Table B-16: Emergency Diesel Engines, Criteria Pollutant Emission Rates

The emission rates in units of g/hp-hr for NO_x, CO, VOC, and PM were provided by the vendor. The horsepower was derived from the electrical output rating (kWe) of the engine. The emission rates for SO_2 were derived from the fuel flow, density, and fuel sulfur content information, which were also provided.

Example: Derivation of Horsepower

Electrical Output Rating = 800 kWe
Assumed Efficiency = 80%

Horsepower = 800 kWe x (1/(80/100)) x hp/0.7457 kW = 1,340 hp

Example: Criteria Pollutant Calculation for NO_x

NO_x Emission Rate = 5.26 g/hp-hr
Operating Hours = 100 hr/yr

NO_x (lb/hr) = 5.26 g/hp-hr x 0.002204 lb/g x 1,340 hp =15.5 lb/hr

NO_x (ton/yr) = 15.5 lb/hr x 100 hr/yr x ton/2,000 lb = 0.78 ton/yr

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Example: Calculation of SO_2 Emissions

Maximum Fuel Flow = 57.2 gal/hr

Fuel Sulfur Content = 0.0015 wt % S (for ULSD fuel oil)

Fuel Density = 7.08 lb/gal

SO_2 (lb/hr) = 57.2 gal/hr x 7.08 lb/gal x 0.0015 % S/100% x 2 lb SO_2/1lb S = 0.012 lb/hr

SO_2 (ton/yr) = 0.012 lb/hr x 100 hr/yr x ton/2,000 lb = 0.0006 ton/yr
SO_2 (g/hp-hr) = 0.012 lb/hr x g/0.0022046 lb x 1/ 1,340 hp = 0.004 g/hp-hr

Table B-17: Emergency Diesel Engines, Hazardous Air Pollutant Emission Rates

The HAPs were based on EPA AP-42 emission factors (Section 3 Table 3.3-2), and the information supplied by the vendor.

Example: Calculation of Formaldehyde Emissions

Maximum Fuel Flow = 57.2 gal/hr

Fuel Heat Content = 138,000 Btu/gal (HHV)

AP-42 Formaldehyde Emission Factor = 0.00118 lb/MMBtu

Operating Hours = 100 hr/yr

Engine Heat Input = 57.2 gal/hr x 138,000 Btu/gal x ($1/10^6$) = 7.89 MMBtu/hr

Formaldehyde (lb/hr) = 0.00118 lb/MMBtu x 7.89 MMBtu/hr = 0.00931 lb/hr

Formaldehyde (ton/yr) = 0.00931 lb/hr x 100 hr/yr x ton/2,000 lb = 0.000466 ton/yr

Table B-18: SCCT Stack Parameters – Natural Gas

The data in this table is also provided in Table B-12. The exhaust velocities and temperatures are shown to more decimal places, but their derivation was previously described.

Table B-19: SCCT Stack Parameters – ULSD Fuel Oil

The data in this table is also provided in Table B-14. The exhaust velocities and temperatures are shown to more decimal places, but their derivation was previously described.

Table B-20: Emergency Diesel Engines, Stack Parameters

The stack height, diameter, flow rate, and exhaust temperature were provided by the vendor. Examples of the conversions, e.g., feet to meters, and the derivation of stack area and exit velocity have previously been given for Table B-12.

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LIST OF ACRONYMS

°F	degrees Fahrenheit
°K	degrees Kelvin
%	percent
acfm	actual cubic feet per minute
AP-42	EPA's Compilation of Air Pollutant Emission Factors, 5th Edition
Btu	British thermal unit
Btu/hr	British thermal units per hour
CO	carbon monoxide
CO_2	carbon dioxide
SCCT	simple cycle combustion turbine
dscfm	dry standard cubic feet per minute
EPA	United States Environmental Protection Agency
ft	feet
ft^2	square feet
ft^3	cubic feet
ft/sec	feet per second
ft^3/min	cubic feet per minute
ft^3/lb-mole	cubic feet per pound mole
gal/hr	gallons per hour
g	gram
g/hp-hr	grams per horsepower hour
g/s	grams per second
gr	grain
gr S	grains of sulfur
gr S/100 ft^3	grains of sulfur per 100 cubic feet
H_2SO_4	sulfuric acid, or sulfuric acid mist
HAP	hazardous air pollutant
HHV	higher heating value
hp	horsepower
hr	hour
hr/yr	hours per year
kW	kilowatt
kWe	kilowatts electric
lb	pounds
lb/ft^3	pounds per cubic feet
lb/gal	pounds per gallon
lb/hr	pounds per hour
lb/sec	pounds per second
LHV	lower heating value
lb/MMBtu	pounds per million British thermal units
MMBtu/hr	million British thermal units per hour
lb-mole	pound mole
lb/lb-mole	pound per pound mole
lb/sec	pound per second
m	meter
m^2	square meters
m/sec	meters per second
min	minute
NG	natural gas
NO_x	nitrogen oxides
O_2	oxygen
PWPS	Pratt & Whitney Power Systems
Pb	lead

TEC BIG BEND STATION
SIMPLE CYCLE COMBUSTION TURBINES UNIT 4
EXPLANATION OF APPENDIX B EMISSION RATE CALCULATIONS

PM	particulate matter
PM_{10}	particulate matter less than 10 microns in aerodynamic diameter
ppmvd	parts per million by volume, dry
S	sulfur
sec	second
sec/min	seconds per minute
SO_2	sulfur dioxide
TEC	Tampa Electric Company
ton/yr	ton per year
ULSD	ultra low sulfur diesel
VOC	volatile organic compound
wt % S	weight percent sulfur
yr	year

ATTACHMENT 4

RESPONSE TO EPC-4

TECHNICAL DATA FOR CATERPILLAR C27 TA
EMERGENCY GENERATOR DIESEL ENGINE

DIESEL GENERATOR SET

CATERPILLAR®

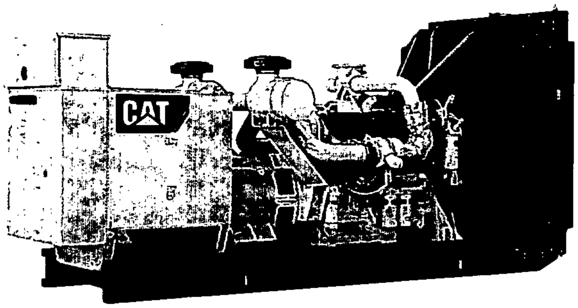

Image shown may not reflect actual package.

STANDBY
800 ekW 1000 kVA
60 Hz 1800 rpm 480 Volts

Caterpillar is leading the power generation marketplace with Power Solutions engineered to deliver unmatched flexibility, expandability, reliability, and cost-effectiveness.

FEATURES

FUEL/EMISSIONS STRATEGY
- EPA Tier 2

DESIGN CRITERIA
- The generator set accepts 100% rated load in one step per NFPA 110 and meets ISO 8528-5 transient response.

UL 2200
- UL 2200 listed packages available. Certain restrictions may apply. Consult with your Caterpillar Dealer.

FULL RANGE OF ATTACHMENTS
- Wide range of bolt-on system expansion attachments, factory designed and tested

SINGLE-SOURCE SUPPLIER
- Fully prototype tested with certified torsional vibration analysis available

WORLDWIDE PRODUCT SUPPORT
- Caterpillar® dealers provide extensive post sale support including maintenance and repair agreements
- Caterpillar dealers fill 99.7% of parts orders within 24 hours
- Caterpillar dealers have over 1,600 dealer branch stores operating in 200 countries
- The Cat® S•O•S℠ program cost effectively detects internal engine component condition, even the presence of unwanted fluids and combustion by-products

CAT C27 ATAAC DIESEL ENGINE
- Utilizes ACERT™ Technology
- Reliable, rugged, durable design
- Four-cycle diesel engine combines consistent performance and excellent fuel economy with minimum weight
- Electronic engine control

CAT SR4B GENERATOR
- Designed to match the performance and output characteristics of Caterpillar diesel engines
- Single point access to accessory connections
- UL 1446 recognized Class H insulation

CAT EMCP 3 SERIES CONTROL PANELS
- Simple user friendly interface and navigation
- Scalable system to meet a wide range of customer needs
- Integrated Control System and Communications Gateway

CATERPILLAR®

FACTORY INSTALLED STANDARD & OPTIONAL EQUIPMENT

System	Standard	Optional
Air Inlet	• Single element canister type air cleaner • Service indicator	• Dual element air cleaners • Air inlet adapters
Cooling	• Radiator with guard (50°C) • Low profile (frontal area) • Low airflow • Coolant drain line with valve • Fan and belt guards • Caterpillar Extended Life Coolant • Coolant level sensors • ATAAC • Duct Flange	• Jacket water heater with shutoff valves
Exhaust	• Dry exhaust manifold • Flanged faced outlets	• Stainless steel exhaust flex fittings • Elbows, flanges, expanders & Y adapters
Fuel	• Primary fuel filter with water separator • Secondary fuel filter • Fuel priming pump • Flexible fuel lines (terminated on base) • Fuel pressure gauge	
Generators	• SR4B Self Excited • Class H insulation • Class F temperature (105°C prime/130°C standby) • Winding temperature detectors (select models) • Anti-condensation space heaters • Power Terminal Strip • Random Wound • Optimum winding pitch	• Oversize & premium generators • Permanent magnet
Power Termination	• Bus bar (NEMA hole connections)a • Bottom cable entry • AC & DC customer wiring area	• Circuit breakers, UL listed, 3 pole with shunt trip, 80% rated
Governor	• ADEM™ A4	
Control Panels	• User Interface panel (UIP) - rear mount • EMCP 3.1 generator set controller • Speed adjust • AC & DC customer wiring area (right side) • CAT Digital Voltage Regulator (CDVR) with KVAR/PF control, 3-phase sensing • Emergency Stop Push button	• EMCP 3.2 and EMCP 3.3 • Option for right or left mount UIP • Option for rear or left mount Customer wiring area • Local & remote annunciator modules • Discrete I/O Module • Generator temperature monitoring & protection • Voltage raise/lower switch
Lube	• Lubricating oil and filter • Oil drain line with valves • Fumes disposal • Gear type lube oil pump	
Mounting	• Structual steel tube • Anti-vibration mounts	
Starting/Charging	• 24 volt starting motor(s) • Batteries with rack and cables • Battery disconnect	• Battery chargers (10 Amp) • 45 amp charging alternator • Oversize batteries • Ether starting aid
General	• Right-hand service • Paint - Caterpillar Yellow (except rails and radiators gloss black) • SAE standard rotation • Flywheel and Flywheel housing - SAE No. 0	• UL 2200 • CSA certification • EU Declaration of Incorporation • EEC Declaration of Conformity

STANDBY 800 ekW 1000 kVA

60 Hz 1800 rpm 480 Volts

CATERPILLAR®

SPECIFICATIONS

CAT GENERATOR

SR4B Generator
Frame size.. 597
Excitation.. Self Excited
Pitch.. 0.8000
Number of poles.. 4
Number of bearings.. Single Bearing
Number of Leads.. 12
Insulation.. UL 1446 Recognized Class H with tropicalization and antiabrasion
IP rating.. Drip Proof IP22
Alignment.. Close Coupled
Overspeed capability - % of rated.. 150
Wave form.. Less than 5% deviation
Paralleling kit/Droop transformer.. Standard
Voltage regulator.3 Phase sensing with selectible volts/Hz
Voltage regulation............Less than +/- 1/2% (steady state)
Less than +/- 1% (no load to full load)
Telephone Influence Factor.. Less than 50
Harmonic distortion.. Less than 5%

CAT DIESEL ENGINE

C27 TA, V-12, 4-stroke-cycle watercooled diesel
Bore - mm.. 137.20 mm (5.4 in)
Stroke - mm.. 152.40 mm (6.0 in)
Displacement - L.. 27.03 L (1649.47 in³)
Compression ratio.. 16.5:1
Aspiration.. TA
Fuel system.. MEUI
Governor type.. ADEM™ A4

CAT EMCP 3 SERIES CONTROLS

• EMCP 3 (Standard)
•Integral to generator terminal box
•Single location for customer connection
•IP 23 enclosure
• 24 Volt DC Control
• UL/CSA/CE/UL508A
• Lockable hinged door (option)
• Run/Auto/Stop control
• True RMS metering, 3-phase
•Speed Adjust
• Voltage adjust (optional on 3.1)
• Digital indications for:
  - RPM
  - Operating hours
  - Oil pressure
  - Coolant temperature
- Low Coolant Level
  - System DC volts
  - L-L volts, L-N volts, phase amps, Hz
- ekW, kVA, kVAR, kW-hr, %kW, PF(*)
• Shutdowns with indicating lights (with optional annunciator):
  - Low oil pressure
  - High coolant temperature
  - Overspeed
  - Emergency stop
  - Failure to start (overcrank)
• Programmable protective relaying functions (*):
  - Under and over voltage
  - Under and over frequency
  - Reverse power
  - Overcurrent (phase & total)
• MODBUS isolated data link (RS-485 half-duplex) supports serial communication at data rate up to 115.2 kbaud (*)
(*) Requires EMCP 3.2 & EMCP 3.3

STANDBY 800 ekW 1000 kVA

60 Hz 1800 rpm 480 Volts

CATERPILLAR®

TECHNICAL DATA

Open Generator Set - - 1800 rpm/60 Hz/480 Volts	DM7696	
EPA Certified Tier 2		
Generator Set Package Performance		
Genset Power rating @ 0.8 pf	1000 kVA	
Genset Power rating with fan	800 ekW	
Coolant to aftercooler temp max		
Coolant to aftercooler temp max	49 ° C	120 ° F
Fuel Consumption		
100% load with fan	216.6 L/hr	57.2 Gal/hr
75% load with fan	171.6 L/hr	45.3 Gal/hr
50% load with fan	122.2 L/hr	32.3 Gal/hr
Cooling System[1]		
Air flow restriction (system)	0.12 kPa	0.48 in. water
Air flow (max @ rated speed for radiator arrangement)	1137 m^3/min	40153 cfm
Engine Coolant capacity with radiator/exp. tank	160.0 L	42.3 gal
Engine coolant capacity	55.0 L	14.5 gal
Radiator coolant capacity	105.0 L	27.7 gal
Inlet Air		
Combustion air inlet flow rate	61.5 m^3/min	2171.9 cfm
Exhaust System		
Exhaust stack gas temperature	512.8 ° C	955.0 ° F
Exhaust gas flow rate	171.2 m^3/min	6045.9 cfm
Exhaust flange size (internal diameter)	203 mm	8 in
Exhaust system backpressure (maximum allowable)	10.0 kPa	40.2 in. water
Heat Rejection		
Heat rejection to coolant (total)	330 kW	18767 Btu/min
Heat rejection to exhaust (total)	767 kW	43619 Btu/min
Heat rejection to aftercooler	157 kW	8929 Btu/min
Heat rejection to atmosphere from engine	164 kW	9327 Btu/min
Heat rejection to atmosphere from generator	36.8 kW	2092.8 Btu/min
Alternator[2]		
Motor starting capability @ 30% voltage dip	2131 skVA	
Frame	597	
Temperature Rise	130 ° C	234 ° F
Lube System		
Sump refill with filter	68.0 L	18.0 gal
Emissions (Nominal)[3]		
NOx g/hp-hr	5.26 g/hp-hr	
CO g/hp-hr	.23 g/hp-hr	
HC g/hp-hr	.03 g/hp-hr	
PM g/hp-hr	.024 g/hp-hr	

[1] For ambient and altitude capabilities consult your Caterpillar dealer. Air flow restriction (system) is added to existing restriction from factory.

[2] UL 2200 Listed packages may have oversized generators with a different temperature rise and motor starting characteristics. Generator temperature rise is based on a 40°C ambient per NEMA MG1-32.

[3] Emissions data measurement procedures are consistent with those described in EPA CFR 40 Part 89, Subpart D & E and ISO8178-1 for measuring HC, CO, PM, NOx. Data shown is based on steady state operating conditions of 77°F, 28.42 in HG and number 2 diesel fuel with 35° API and LHV of 18,390 btu/lb. The nominal emissions data shown is subject to instrumentation, measurement, facility and engine to engine variations. Emissions data is based on 100% load and thus cannot be used to compare to EPA regulations which use values based on a weighted cycle.

0

RATING DEFINITIONS AND CONDITIONS

Meets or Exceeds International Specifications: AS1359, CSA, IEC60034, ISO3046, ISO8528, NEMA MG 1-33, UL508A, 98/37/EC
Standby - Output available with varying load for the duration of the interruption of the normal source power. Average power output is 70% of the standby power rating. Typical operation is 200 hours per year, with maximum expected usage of 500 hours per year. Standby power in accordance with ISO8528. Fuel stop power in accordance with ISO3046. Standby ambients shown indicate ambient temperature at 100% load which results in a coolant top tank temperature just below the shutdown temperature.

Ratings are based on SAE J1995 standard conditions. These ratings also apply at ISO3046,standard conditions.
Fuel Rates are based on fuel oil of 35° API [16° C (60° F)] gravity having an LHV of 42 780 kJ/kg (18,390 Btu/lb) when used at 29° C (85° F) and weighing 838.9 g/liter (7.001 lbs/U.S. gal.). Additional ratings may be available for specific customer requirements, contact your Caterpillar representative for details. For information regarding Low Sulfur fuel and Biodiesel capability, please consult your Caterpillar dealer.

STANDBY 800 ekW 1000 kVA

60 Hz 1800 rpm 480 Volts

CATERPILLAR®

DIMENSIONS

Package Dimensions		
Length	**4668.7 mm**	**183.81 in**
Width	**1904.6 mm**	**74.98 in**
Height	**2080.5 mm**	**81.91 in**
Weight	**6373 kg**	**14,050 lb**

Note: Do not use for installation design. See general dimension drawings for detail (Drawing #3071564).

Performance No.: DM7696

Feature Code:: C27DE33

Source:: U.S. Sourced

September 20 2007

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ATTACHMENT 5

RESPONSE TO EPC-3

REVISED APPENDIX B EMISSION RATE CALCULATIONS
TABLES B-1, B-3, B-8, B-13, and B-15

Table B-1. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
Annual Emission Rate Summary

Pollutant	Potential Annual Emissions (ton/yr)		
	PWPS CTs (2 CTs)[1]	Emergency Diesel Engine	Project Totals
<u>Criteria Pollutants</u>			
NO_x	121.7	0.8	**122.4**
CO	16.5	0.034	**16.5**
VOC	4.7	0.0044	**4.7**
SO_2	6.6	0.00061	**6.6**
PM_{10} (filterable + condensable)	11.3	0.0035	**11.3**
Pb	0.0006	Neg.	**0.00062**
<u>Hazardous Air Pollutants</u>			
Formaldhyde[2]	0.4	Neg.	**0.4**
Total HAPs	0.6	Neg.	**0.6**
Other Pollutants			
H_2SO_4 Mist	0.8	Neg.	**0.8**
PM (filterable)[3]	11.3	0.0035	**11.3**
Other Constituents			
CO_2	136,865	65	**136,930**

N/A - not applicable
Neg. - negligible

[1] Maximum of Annual Profile 1 (3,500 hrs/yr/CT natural gas)
or Annual Profile 2 (3,000 hrs/yr/CT natural gas + 500 hrs/yr/CT ULSD fuel oil).
[2] Maximum individual HAP.
[3] For PWPS CTs, all PM is $PM_{2.5}$ or less. PM (filterable) is assumed to be 50% of total PM.

Sources: ECT, 2008.
PWPS, 2008.
TEC, 2008.

Table B-3. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
Hourly PM/PM_{10}, SO_2, H_2SO_4 Mist, and Pb Emission Rates (Per CT) - Natural Gas

Temp. (°F)	Case	Load (%)	PM/PM_{10} [1]		SO_2 [2]		H_2SO_4 [3]		Lead [4]	
			(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)
20	1-Gas	100	2.5	0.32	1.87	0.24	0.21	0.027	0.00017	0.000021
	2-Gas	75	2.5	0.32	1.45	0.18	0.17	0.021	0.00013	0.000016
	3-Gas	50	2.5	0.32	1.06	0.13	0.12	0.015	0.00009	0.000012
59	4-Gas	100	2.5	0.32	1.89	0.24	0.22	0.027	0.00017	0.000021
	5-Gas	75	2.5	0.32	1.47	0.19	0.17	0.021	0.00013	0.000016
	6-Gas	50	2.5	0.32	1.08	0.14	0.12	0.016	0.00010	0.000012
90	7-Gas	100	2.5	0.32	1.79	0.23	0.21	0.026	0.00016	0.000020
	8-Gas	75	2.5	0.32	1.41	0.18	0.16	0.020	0.00012	0.000016
	9-Gas	50	2.5	0.32	1.04	0.13	0.12	0.015	0.00009	0.000012
		Maximums	**2.5**	**0.32**	**1.89**	**0.24**	**0.22**	**0.027**	**0.00017**	**0.000021**

1 Total particulate matter as measured by EPA RM 201 or 201A, and 202.
2 Based on natural gas sulfur content of 2.0 gr/100 ft^3.
3 Based on 7.5% conversion of SO_2 to H_2SO_4.
4 Lead emission factor, EPA AP-42, Section 1.4 Natural Gas Combustion, Table 1.4-2., July 1998.

Sources: ECT, 2008.
PWPS, 2008.

Table B-8. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
Hazardous Air Pollutant Hourly Emission Rates - ULSD (Per CT)

Parameter			Units	Value								
Scenario			N/A	1-O	2-O	3-O	4-O	5-O	6-O	7-O	8-O	9-O
Maximum CT Hourly Fuel Flow:			10^6 Btu/hr (HHV)	296.2	233.9	173.0	302.7	238.7	176.4	307.6	242.7	179.1

Hazardous Air Pollutant	No. 2 FO Metals Concentration[1] (ppbw)	No. 2 FO Metals Concentration[2] (ppbw)	Oil Emission Factor[3,4,5,6] (lb/10^6 Btu)	Hourly Emissions 1-O (lb/hr)	2-O (lb/hr)	3-O (lb/hr)	4-O (lb/hr)	5-O (lb/hr)	6-O (lb/hr)	7-O (lb/hr)	8-O (lb/hr)	9-O (lb/hr)
1,3-Butadiene			8.00E-06	2.37E-03	1.87E-03	1.38E-03	2.42E-03	1.91E-03	1.41E-03	2.46E-03	1.94E-03	1.43E-03
Acetaldehyde												
Acrolein												
Arsenic (As)	N/A	<DL	1.10E-05	3.26E-03	2.57E-03	1.90E-03	3.33E-03	2.63E-03	1.94E-03	3.38E-03	2.67E-03	1.97E-03
Benzene			2.75E-05	8.15E-03	6.43E-03	4.76E-03	8.33E-03	6.56E-03	4.85E-03	8.46E-03	6.67E-03	4.92E-03
Beryllium (Be)	N/A	N/A	3.10E-07	9.18E-05	7.25E-05	5.36E-05	9.38E-05	7.40E-05	5.47E-05	9.53E-05	7.52E-05	5.55E-05
Cadmium (Cd)	N/A	<DL	4.80E-06	1.42E-03	1.12E-03	8.30E-04	1.45E-03	1.15E-03	8.47E-04	1.48E-03	1.16E-03	8.60E-04
Chromium (Cr)	31.0	242.4	1.24E-05	3.67E-03	2.90E-03	2.14E-03	3.75E-03	2.96E-03	2.19E-03	3.81E-03	3.01E-03	2.22E-03
Ethylbenzene												
Formaldehyde			1.75E-05	5.18E-03	4.09E-03	3.03E-03	5.30E-03	4.18E-03	3.09E-03	5.38E-03	4.25E-03	3.13E-03
Lead (Pb)	5.3	15.0	7.67E-07	2.27E-04	1.79E-04	1.33E-04	2.32E-04	1.83E-04	1.35E-04	2.36E-04	1.86E-04	1.37E-04
Manganese (Mn)	1.9	5.5	2.81E-07	8.33E-05	6.58E-05	4.87E-05	8.52E-05	6.71E-05	4.96E-05	8.65E-05	6.83E-05	5.04E-05
Mercury (Hg)	<DL	N/A	1.20E-06	3.55E-04	2.81E-04	2.08E-04	3.63E-04	2.86E-04	2.12E-04	3.69E-04	2.91E-04	2.15E-04
Naphthalene			1.75E-05	5.18E-03	4.09E-03	3.03E-03	5.30E-03	4.18E-03	3.09E-03	5.38E-03	4.25E-03	3.13E-03
Nickel (Ni)	2.0	28.9	1.48E-06	4.38E-04	3.46E-04	2.56E-04	4.47E-04	3.53E-04	2.61E-04	4.55E-04	3.59E-04	2.65E-04
Polycyclic Aromatic Hydrocarbons			2.00E-05	5.92E-03	4.68E-03	3.46E-03	6.05E-03	4.77E-03	3.53E-03	6.15E-03	4.85E-03	3.58E-03
Propylene Oxide												
Selenium (Se)	1.9	<DL	9.72E-08	2.88E-05	2.27E-05	1.68E-05	2.94E-05	2.32E-05	1.71E-05	2.99E-05	2.36E-05	1.74E-05
Toluene												
Xylene												
Maximum Individual HAP				**0.008**	**0.006**	**0.005**	**0.008**	**0.007**	**0.005**	**0.008**	**0.007**	**0.005**
Total HAPs				**0.036**	**0.029**	**0.021**	**0.037**	**0.029**	**0.022**	**0.038**	**0.030**	**0.022**

N/A - not available   <DL - less than detection limit   ppbw - parts per billion, by weight

[1] - Analysis of Motor-Vehicle Fuels for Metals by Inductively Coupled Plasma-Mass Spectrometry, University of Iowa, 2000.
[2] - Survey of Ultra-Trace Metals in Gas Turbine Fuels, Siemens Westinghouse Power Corporation & Texas Oil Tech Laboratories, October 2004.
[3] - Organic pollutant emission factors reduced by 50% percent due to use of oxidation catalyst.
[4] - Organic emission factors, EPA AP-42, Stationary Gas Turbines, Table 3.1-4., April 2000.
[5] - Metallic emission factors for As, Be, Cd, and Hg; EPA AP-42, Stationary Gas Turbines, Table 3.1-5., April 2000.
[6] - Metallic emission factors for Cr, Pb, Mn, Ni, and Se; higher of University of Iowa and Siemens Westinghouse data.

Sources: ECT, 2008.
PWPS, 2008.

Table B-13. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
CT Fuel Flow Rate Data (Per CT) - Natural Gas*

	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1-Gas	4-Gas	7-Gas	2-Gas	5-Gas	8-Gas	3-Gas	6-Gas	9-Gas
Heat Input - LHV (MMBtu/hr)	305.2	308.9	291.4	236.1	239.5	229.4	173.6	175.9	169.1
Heat Input - HHV (MMBtu/hr)	338.6	342.7	323.3	261.9	265.7	254.5	192.6	195.2	187.6
Fuel Rate (lb/hr)	14,763	14,945	14,099	11,420	11,585	11,097	8,396	8,511	8,182
Fuel Rate (10^6 ft^3/hr)	0.328	0.332	0.313	0.253	0.257	0.246	0.186	0.189	0.182
Fuel Rate (lb/sec)	4.101	4.151	3.916	3.172	3.218	3.082	2.332	2.364	2.273

*Includes 7.0-percent margin.

Sources: ECT, 2008.
PWPS, 2008.

Table B-15. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
CT Fuel Flow Rate Data (Per CT) - ULSD Fuel Oil*

	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1-ULSD	4-ULSD	7-ULSD	2-ULSD	5-ULSD	8-ULSD	3-ULSD	6-ULSD	9-ULSD
Heat Input - LHV (MMBtu/hr)	278.2	284.3	288.8	219.6	224.1	227.9	162.4	165.6	168.1
Heat Input - HHV (MMBtu/hr)	296.2	302.7	307.6	233.9	238.7	242.7	173.0	176.4	179.1
Fuel Rate (lb/hr)	15,150	15,483	15,730	11,960	12,208	12,411	8,846	9,020	9,158
Fuel Rate (10^3 gal/hr)	2.225	2.274	2.310	1.756	1.793	1.823	1.299	1.325	1.345
Fuel Rate (lb/sec)	4.208	4.301	4.369	3.322	3.391	3.447	2.457	2.506	2.544

*Includes 7.0-percent margin.

Sources: ECT, 2008.
PWPS, 2008.

FT8-3 Swift Pac (with CO Converter)
Sheet-1, Notes Applicable to Performance and Emissions Data
Tampa-Electric

Perf_CustCpy_Tampa_Electric_FT8-3_AS_R3-012508.xls

Notes:

0. All Performance/Emissions Data submitted are subject to the sum of the following notes.
1. The Swift Pac (SP) consists of two turbines driving a common generator. Rates are shown as per GT, and per Swift Pac (2-GT's).
2. Gaseous fuel supplied to gas turbines must meet PWPS fuel specification FR-2, liquid fuel must meet FR-1.
3. Water used for burner injection must meet PWPS specification AR-1 (demin water).
4. Primary NOx control by water injection.
5. Data shown for GT water injection to 25 ppmvd @15% O2 for gas fuel and 42 ppmvd @15% O2 for liquid fuel.
6. All data supplied based on altitude of Sea Level Alt. (14.696 psia).
7. Engine performance with chiller in-service is based on a compressor inlet temperature of 10C.
8. Supply of chiller coils to the inlet is by PWPS, with chiller system provided by others.
9. Performance to be corrected for changes in ambient temperature, ambient pressure, and relative humidity from the guarantee reference conditions, whether the chiller is in-service or not.
10. In the event that the combination of ambient conditions and chiller performance can not meet 10C inlet temperature, then a root-cause investigation shall be funded by the Customer, with the supplier responsible for the shortfall being financially responsible for the miss.
11. Inlet loss estimated at 3.2 in W.C. with inlet Evaporative Cooler, and 3.5 in W.C. with Chiller.
    No correction of test results for inlet loss.
12. Exhaust loss for all cases estimated at 6 in W.C. for CO conv. System and 60 ft Braden exhaust stack.
    All emission concentrations corrected to 15% O2.
13. Secondary cooling air is separately exhausted from the Primary GT exhaust flow for the option with CO converter.

13A. Exhaust exit velocity is based on 70.882 ft2 exit discharge area of the 60 ft Braden stack.

14. Data designated as "primary exhaust" is referenced to the GT exhaust and does not include secondary cooling air.
15. All data submitted is based upon 72-290 generator operating at 60Hz and 0.85 power factor @13.8 kV.
16. Net Power = Power measured at the generator terminals, minus power island auxiliary and EVAP loads.

16A. BOP loads, GSU losses, Chiller and gas compression loads are not included in Net Power output or Net Heat Rate determinations.

17. Guaranteed values indicated by the following designations, all other data are estimates: (G) or $\boxed{\textbf{value}}$
18. Performance Acceptance Test for GT Net Power Output and GT Net Heat Rates to be conducted per PWPS test procedures, instrumentation, and calculations; all being in accordance with ASME PTC-22 and PTC-19.1, which shall meet or exceed the requirements of ISO 2314, ISO 5167, and ISO 6976.
19. Performance acceptance testing for GT Net Power Output and GT Net Heat Rate shall be furnished by PWPS through independent third party contractor.
20. Performance and emissions are based upon assumed fuel compositions shown on sheet - 2.
21. SO2 data is estimated from Sulfur contents stated on sheet - 2, which PWPS does not control and therefore can't guarantee.
22. Emission data is representative of steady-state operation, and may not be indicative of transient operation.
23. Demonstration of (G) emission concentrations for NOx, CO, and VOC's are based on 1-hour averages, after operation under steady-state conditions for 2-hours.
24. Volatile Organic Compounds (VOC) are defined as non methane, non ethane, > 85% of the composition being ethene. Values shown are based upon PWPS experience and measurement using EPA Method 25.3.
25. Testing for PM10 shall conform to PWPS Quality Assurance documentation in addition to EPA Methods 25, 201, 202.
26. PM10 testing to (G) levels shall require 4 test runs of 4-hour duration per fuel, with the high run rejected.
    Volumetric flow rate for determination of PM10 to be per EPA Method 19, which utilized fuel flow, O2%, and F-factors.
27. PM10 testing to Method 202 shall utilize best-practices shown at http://www.epa.gov/ttn/emc/methods/method202.html for the reduction in positive biases relating "to the oxidation of soluble gases inadvertently captured in the cold impinger solutions used in Method 202 sampling trains", including but not limited to sampling trains "without the use of water-filled impingers", and/or correction of results to reduce positive bias error. In the event of high test results, retest data shall have PM10 contributions from the gas turbine inlets.
28. In consideration of high bias issues with PM10 measurements by R/M 202, PWPS may test with R/M 20X for both filt & cond PM10.
29. Emission guarantees are valid when tested by Emissions Contractor specified by PWPS.
30. Installation, commissioning, and operation of CO catalysts must be in accordance with manufacturers specification.

FT8-3 Swift Pac (with CO Converter)
Assumed Fuel Properties
Tampa-Electric

The following fuel properties are assumed as representative of site fuels, based on specified data.

Specified Natural Gas			Units	
	Volume - Mol %	Hydrogen to Carbon Ratio	$H_{(mw)} / C_{(mw)}$	0.328
Methane	95.08	Hydrocarbon Molecular Weight		16.712
Ethane	2.53	Gas Molar Weight		17.042
Propane	0.43	Higher Heating Value	Btu/lb	22,933
N-Butane	0.12		kJ/kg	53,342
Isobutane	0.09		Btu/SCF	1,034
N-Pentane	0.03		kJ/Nm3	3,848
Isopentane	0.04	Lower Heating Value	Btu/lb	20,671
N-Hexane	0.08		kJ/kg	48,081
Nitrogen	0.88		Btu/SCF	931.6
CO2 & He	0.72		kJ/Nm3	3,469
Total	100.0	Ratio HHV/LHV		1.109
		Specific Gravity		0.5884
		Assumed Max Sulfur	grains/100 scf	0.50
			mg/Nm3	12
			Weight %	0.002

Specified Liquid Fuel (ULSD)				
	Assumed Wt %		Units	
Carbon	87.16	Hydrogen to Carbon Ratio		0.1470
Hydrogen	12.81	Higher Heating Value	Btu/lb	19553
Nitrogen	0.015		kJ/kg	45480
Oxygen	0.010	Lower Heating Value	Btu/lb	18360
Sulfur Max	0.0015		kJ/kg	42705
Total	100.0	Ratio HHV/LHV		1.065
		Specific Gravity		0.816

FT8-3 Swift Pac (with CO Converter)
Estimated Performance and Emissions, 100% Base-Load Data
Tampa-Electric

Configuration: Standard NE US Gas Fuel, WI to 25 ppmvd NOx @ 15% O2, Sea Level Alt., 55% Ambient RH, 72-290 Generator at 60 Hz, 13.8 kV, 0.85 pf Simple-Cycle

														Sim Chiller
Performance Data														
Fuel Type		Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas
Percent of Swift Pac Unit Rating	%	100	100	100	100	100	100	100	100	100	100	100	100	100
Ambient Temperature	Deg F	10	30	49	70	92	110	60	70	80	92	100	110	92
Evaporative Cooler In-Service	Yes / No	No	No	No	No	No	No	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	No
Chiller in Service	Yes / No	No	No	No	No	No	No	No	No	No	No	No	No	**Yes**
Compressor Inlet Temperature	Deg F	10	30	49	70	92	110	53	61	70	80	87	96	50
Ambient Pressure	Psia	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70
Relative Humidity	%	55	55	55	55	55	55	55	55	55	55	55	55	100
Inlet Loss	Inch H20	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.5
Exhaust Loss	Inch H20	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Fuel Supply Temperature	Deg F	59	59	59	59	59	59	59	59	59	59	59	59	59
Fuel LHV	Btu/lb	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671
Fuel HHV	Btu/lb	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932
Ratio of HHV to LHV		1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109
Gross Power Output	MWe	62.423	62.501	62.466	58.939	54.220	49.924	62.017	60.649	59.176	57.228	55.859	54.263	62.367
Gross Heat Rate, HHV	Btu/kWhr	10,074	10,176	10,285	10,408	10,638	10,925	10,311	10,359	10,423	10,514	10,591	10,692	10,304
Power Island and Evap Aux Loads	kW	252	252	252	252	252	252	260	260	260	260	260	260	252
Net Power Output	MWe	62.171	62.249	62.214	58.687	53.968	49.672	61.757	60.389	58.916	56.968	55.599	54.003	62.115
Net Heat Rate, HHV	Btu/kWhr	10,115	10,218	10,327	10,452	10,858	10,980	10,354	10,404	10,469	10,731	10,640	10,743	10,346
Fuel Flow, per GT	lbs/hr	13,711	13,868	14,008	13,374	12,575	11,892	13,942	13,698	13,448	13,118	12,899	12,650	14,011
Burner Water Injection Flow, per GT	gal/min	28.7	30.1	31.3	30.1	28.4	27.0	31.2	30.7	30.3	29.6	29.1	28.6	31.4
EVAP Water Flow Rate, per GT	gal/min	0.0	0.0	0.0	0.0	0.0	0.0	2.4	2.8	3.1	3.5	3.8	4.0	0.0
Gaseous Fuel Flow @ 15C, per GT	SCF/hr	304,228	307,705	310,816	296,760	279,029	263,861	309,351	303,939	298,389	291,079	286,203	280,680	310,891
Emissions at GT Exit*														
NOx	ppmvd	25	25	25	25	25	25	25	25	25	25	25	25	25
NOx, as NO2, per GT	lbs/hr	31.4	31.7	32.1	30.6	28.8	27.2	31.9	31.4	30.8	30.0	29.5	29.0	32.1
VOC as C1	ppmvd	6.8	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
VOC as C1, per GT	lbs/hr	3.0	2.6	2.7	2.6	2.4	2.3	2.7	2.6	2.6	2.5	2.5	2.4	2.7
SO2	ppmvd	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
SO2, per GT	lbs/hr	0.48	0.48	0.49	0.47	0.44	0.41	0.49	0.48	0.47	0.46	0.45	0.44	0.49
TSP/PM10, Filterable and Cond, per GT	lbs/hr	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Exhaust Gas Flow, per GT **	lbs/sec	214	210	205	196	185	174	203	200	196	191	187	183	204
Exhaust Gas Temperature **	Deg F	806	849	890	908	930	954	893	901	909	919	927	937	892
Exhaust Gas Molecular Weight, Wet		28.26	28.21	28.14	28.07	27.92	27.72	28.08	28.03	27.97	27.88	27.79	27.67	28.08
Exhaust Gas Vol Flow Rate, per GT **	ACFS	7,012	7,098	7,176	6,978	6,706	6,459	7,158	7,084	7,005	6,897	6,824	6,741	7,178
Stack Exhaust Velocity, per GT **	ft/s	98.9	100.1	101.2	98.4	94.6	91.1	101.0	99.9	98.8	97.3	96.3	95.1	101.3
H2O	% Vol wet	8.98	9.55	10.25	10.89	12.18	14.04	10.81	11.21	11.76	12.62	13.37	14.55	10.80
O2	% Vol wet	13.7	13.4	13.1	12.9	12.7	12.3	12.9	12.9	12.8	12.6	12.4	12.2	12.9
CO2	% Vol wet	3.09	3.19	3.28	3.27	3.25	3.24	3.29	3.28	3.28	3.27	3.27	3.27	3.29
A	% Vol wet	0.873	0.869	0.863	0.857	0.845	0.827	0.858	0.854	0.849	0.841	0.834	0.823	0.858
N2	% Vol wet	73.4	73.0	72.5	72.0	71.0	69.5	72.1	71.8	71.4	70.7	70.1	69.2	72.1
Treated Exhaust Characteristics (Post CO Converter)*														
CO	ppmvd	8.7	8.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
CO, perGT	lbs/hr	6.6	6.2	4.7	4.5	4.2	4.0	4.7	4.6	4.5	4.4	4.3	4.2	4.7
Estimated Chiller Load Calculations														
Air Enthalpy into Chiller	Btu/lb													41.80
Air Enthalpy out off Chiller	Btu/lb													20.30
Delta Enthalpy through Chiller	Btu/lb													21.50
Airflow through Chiller, per GT	pps													197.06
Air Enthalpy removed by Chiller	Btu/s													4,237
Tons of Refrigeration, per GT	ton													1,271
Chiller load, per GT	kW													1,042
Chiller load, per SP	kW													2,084

Notes:
* All ppmvd corrected to 15% O2
** Secondary Cooling Air Separately Exhausted

Guaranteed values are indicated by (G), or $\boxed{\text{value}}$
All other data are estimates.

FT8-3 Swift Pac (with CO Converter)
Estimated Performance and Emissions, Part-Load Data
Tampa-Electric

Configuration: Standard NE US Gas Fuel, WI to 25 ppmvd NOx @ 15% O2, Sea Level Alt., 55% Ambient RH, 72-290 Generator at 60 Hz, 13.8 kV, 0.85 pf Simple-Cycle

Performance Data																
Fuel Type		Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas
Percent of Swift Pac Unit Rating	%	100	83	75	67	50	100	83	75	67	50	100	83	75	67	50
Ambient Temperature	Deg F	20	20	20	20	20	59	59	59	59	59	90	90	90	90	90
Evaporative Cooler In-Service	Yes / No	No	No	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Chiller in Service	Yes / No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Compressor Inlet Temperature	Deg F	20	20	20	20	20	52	52	52	52	52	79	79	79	79	79
Ambient Pressure	Psia	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70
Relative Humidity	%	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Inlet Loss	Inch H20	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Exhaust Loss	Inch H20	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Fuel Supply Temperature	Deg F	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
Fuel LHV	Btu/lb	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671
Fuel HHV	Btu/lb	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932
Ratio of HHV to LHV		1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109
Gross Power Output	MWe	62.501	51.876	46.876	41.876	31.251	62.155	51.589	46.617	41.644	31.078	57.586	47.797	43.190	38.583	28.793
Gross Heat Rate, HHV	Btu/kWhr	10,125	10,255	10,442	10,700	11,517	10,306	10,459	10,652	10,909	11,738	10,495	10,793	11,013	11,287	12,181
Power Island and Evap Aux Loads	kW	252	252	252	252	252	260	260	260	260	260	260	260	260	260	260
Net Power Output	MWe	62.249	51.624	46.624	41.624	30.999	61.895	51.329	46.357	41.384	30.818	57.326	47.537	42.930	38.323	28.533
Net Heat Rate, HHV	Btu/kWhr	10,166	10,305	10,499	10,765	11,611	10,349	10,512	10,712	10,977	11,837	10,543	10,852	11,080	11,364	12,292
Fuel Flow, per GT	lbs/hr	13,797	11,599	10,673	9,770	7,847	13,967	11,764	10,827	9,905	7,954	13,177	11,248	10,371	9,495	7,647
Burner Water Injection Flow, per GT	gal/min	29.4	22.8	20.4	18.1	13.3	31.3	24.5	21.9	19.4	14.5	29.7	24.0	21.5	19.2	14.4
EVAP Water Flow Rate, per GT	gal/min	0.0	0.0	0.0	0.0	0.0	2.3	2.2	2.1	2.0	1.8	3.4	3.2	3.1	2.9	2.6
Gaseous Fuel Flow @ 15C, per GT	SCF/hr	306,139	257,365	236,811	216,777	174,125	309,905	261,032	240,229	219,772	176,484	292,386	249,577	230,119	210,687	169,676
Emissions at GT Exit*																
NOx	ppmvd	25	25	25	25	25.5	25	25	25	25	25	25	25	25	25	25
NOx, as NO2, per GT	lbs/hr	31.6	26.5	24.4	22.3	18.2	32.0	26.9	24.8	22.6	18.2	30.2	25.7	23.7	21.7	17.5
VOC as C1	ppmvd	6.0	13.9	15.6	16.7	40.4	6.0	7.4	11.0	14.0	17.2	6.0	6.0	7.6	11.2	16.0
VOC as C1, per GT	lbs/hr	2.6	5.1	5.3	5.2	10.1	2.7	2.8	3.8	4.4	4.3	2.5	2.1	2.5	3.4	3.9
SO2	ppmvd	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
SO2, per GT	lbs/hr	0.48	0.40	0.37	0.34	0.27	0.49	0.41	0.38	0.35	0.28	0.46	0.39	0.36	0.33	0.27
TSP/PM10, Filterable and Cond, per GT	lbs/hr	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Exhaust Gas Flow, per GT **	lbs/sec	212	198	190	181	161	204	190	182	173	153	192	177	169	161	143
Exhaust Gas Temperature **	Deg F	828	765	748	733	701	893	834	817	802	767	917	879	864	848	814
Exhaust Gas Molecular Weight, Wet		28.23	28.33	28.36	28.39	28.46	28.08	28.17	28.21	28.24	28.31	27.89	27.97	28.00	28.03	28.10
Exhaust Gas Vol Flow Rate, per GT **	ACFS	7,058	6,263	5,910	5,558	4,783	7,166	6,360	6,000	5,638	4,847	6,917	6,186	5,843	5,495	4,734
Stack Exhaust Velocity, per GT **	ft/s	99.6	88.4	83.4	78.4	67.5	101.1	89.7	84.6	79.5	68.4	97.6	87.3	82.4	77.5	66.8
H2O	% Vol wet	9.25	8.14	7.76	7.41	6.57	10.77	9.68	9.29	8.90	8.05	12.45	11.62	11.24	10.86	10.00
O2	% Vol wet	13.5	14.3	14.6	14.8	15.4	12.9	13.7	14.0	14.2	14.9	12.6	13.2	13.5	13.7	14.4
CO2	% Vol wet	3.14	2.83	2.72	2.62	2.38	3.29	2.99	2.88	2.77	2.52	3.27	3.04	2.93	2.82	2.57
A	% Vol wet	0.871	0.879	0.881	0.884	0.889	0.858	0.866	0.868	0.871	0.877	0.842	0.848	0.851	0.853	0.859
N2	% Vol wet	73.2	73.8	74.1	74.3	74.7	72.1	72.8	73.0	73.2	73.7	70.8	71.3	71.5	71.7	72.2
Treated Exhaust Characteristics (Post CO Converter)*																
CO	ppmvd	8.0	13.3	14.1	14.6	20.9	6.0	9.2	11.6	13.3	14.8	6.0	8.0	9.3	11.7	14.3
CO, per GT	lbs/hr	6.2	8.6	8.4	7.9	9.1	4.7	6.0	7.0	7.3	6.6	4.4	5.0	5.4	6.2	6.1
Estimated Chiller Load Calculations																
Air Enthalpy into Chiller	Btu/lb															
Air Enthalpy out off Chiller	Btu/lb															
Delta Enthalpy through Chiller	Btu/lb															
Airflow through Chiller, per GT	pps															
Air Enthalpy removed by Chiller	Btu/s															
Tons of Refrigeration, per GT	ton															
Chiller load, per GT	kW															
Chiller load, per SP	kW															

Notes:
- * All ppmvd corrected to 15% O2
- ** Secondary Cooling Air Separately Exhausted

Guaranteed values are indicated by (G), or $\boxed{\text{value}}$
All other data are estimates.

FT8-3 Swift Pac (with CO Converter)
Estimated Performance and Emissions, 100% Base-Load Data
Tampa-Electric

Configuration: Specified Liquid Fuel (ULSD), WI to 42 ppmvd NOx @ 15% O2,
Sea Level Alt., 55% Ambient RH, 72-290 Generator at 60 Hz, 13.8 kV, 0.85 pf Simple-Cycle

														Sim Chiller
Performance Data														
Fuel Type		Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid
Percent of Swift Pac Unit Rating	%	100	100	100	100	100	100	100	100	100	100	100	100	100
Ambient Temperature	Deg F	10	30	50	75	92	110	60	75	89	92	100	110	92
Evaporative Cooler In-Service	Yes / No	No	No	No	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes	No
Chiller in Service	Yes / No	No	No	No	No	No	No	No	No	No	No	No	No	Yes
Compressor Inlet Temperature	Deg F	10	30	50	75	92	110	53	66	78	80	87	96	50
Ambient Pressure	Psia	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70
Relative Humidity	%	55	55	55	55	55	55	55	55	55	55	55	55	100
Inlet Loss	Inch H20	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.5
Exhaust Loss	Inch H20	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Fuel Supply Temperature	Deg F	127	127	127	127	127	127	127	127	127	127	127	127	127
Fuel LHV	Btu/lb	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360
Fuel HHV	Btu/lb	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553
Ratio of HHV to LHV		1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065
Gross Power Output	MWe	56.048	56.126	56.182	56.287	52.189	48.013	56.202	56.267	56.203	55.668	54.238	51.990	56.090
Gross Heat Rate, HHV	Btu/kWhr	9,822	9,936	10,057	10,217	10,446	10,740	10,080	10,166	10,253	10,282	10,365	10,519	10,070
Power Island and Evap Aux Loads	kW	277	277	277	277	277	277	285	285	285	285	285	285	277
Net Power Output	MWe	55.771	55.849	55.905	56.010	51.912	47.736	55.917	55.982	55.918	55.383	53.953	51.705	55.813
Net Heat Rate, HHV	Btu/kWhr	9,871	9,985	10,107	10,268	10,670	10,802	10,131	10,218	10,305	10,500	10,420	10,577	10,120
Fuel Flow, per GT	lbs/hr	14,076	14,259	14,448	14,705	13,940	13,185	14,486	14,626	14,735	14,636	14,375	13,984	14,443
Burner Water Injection Flow, per GT	gal/min	28.7	30.4	32.1	34.3	32.6	31.0	32.3	33.5	34.4	34.2	33.7	32.8	32.1
EVAP Water Flow Rate, per GT	gal/min	0.0	0.0	0.0	0.0	0.0	0.0	2.3	2.9	3.4	3.5	3.7	3.9	0.0
Gaseous Fuel Flow @ 15C, per GT	SCF/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Emissions at GT Exit*														
NOx	ppmvd	42	42	42	42	42	42	42	42	42	42	42	42	42
NOx, as NO2, per GT	lbs/hr	49.1	49.7	50.4	51.3	48.6	46.0	50.5	51.0	51.4	51.1	50.2	48.8	50.4
VOC as C1	ppmvd	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
VOC as C1, per GT	lbs/hr	2.0	2.1	2.1	2.1	2.0	1.9	2.1	2.1	2.1	2.1	2.1	2.0	2.1
SO2	ppmvd	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
SO2, per GT	lbs/hr	0.46	0.47	0.48	0.49	0.46	0.44	0.48	0.48	0.49	0.48	0.47	0.46	0.48
TSP/PM10, Filterable and Cond, per GT	lbs/hr	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Exhaust Gas Flow, per GT **	lbs/sec	208	203	198	192	182	171	197	194	191	190	186	180	197
Exhaust Gas Temperature **	Deg F	771	815	860	915	936	959	866	894	920	923	931	943	860
Exhaust Gas Molecular Weight, Wet		28.66	28.61	28.55	28.42	28.30	28.09	28.49	28.40	28.28	28.25	28.17	28.04	28.49
Exhaust Gas Vol Flow Rate, per GT **	ACFS	6,520	6,599	6,679	6,785	6,548	6,307	6,694	6,752	6,799	6,769	6,691	6,567	6,678
Stack Exhaust Velocity, per GT **	ft/s	92.0	93.1	94.2	95.7	92.4	89.0	94.4	95.3	95.9	95.5	94.4	92.6	94.2
H2O	% Vol wet	6.59	7.15	7.89	9.27	10.37	12.25	8.47	9.40	10.55	10.79	11.55	12.74	8.40
O2	% Vol wet	14.3	14.0	13.6	13.1	12.9	12.5	13.5	13.2	12.8	12.8	12.6	12.4	13.5
CO2	% Vol wet	3.93	4.08	4.22	4.41	4.39	4.39	4.24	4.34	4.42	4.42	4.42	4.42	4.22
A	% Vol wet	0.884	0.879	0.873	0.861	0.851	0.833	0.868	0.860	0.849	0.847	0.840	0.829	0.868
N2	% Vol wet	74.3	73.9	73.4	72.3	71.5	70.0	72.9	72.2	71.4	71.2	70.6	69.6	73.0
Treated Exhaust Characteristics (Post CO Converter)*														
CO	ppmvd	2.3	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
CO, per GT	lbs/hr	1.6	1.4	1.5	1.5	1.4	1.3	1.5	1.5	1.5	1.5	1.5	1.4	1.5
Estimated Chiller Load Calculations														
Air Enthalpy into Chiller	Btu/lb													41.80
Air Enthalpy out off Chiller	Btu/lb													20.30
Delta Enthalpy through Chiller	Btu/lb													21.50
Airflow through Chiller, per GT	pps													189.99
Air Enthalpy removed by Chiller	Btu/s													4,085
Tons of Refrigeration, per GT	ton													1,225
Chiller load, per GT	kW													1,005
Chiller load, per SP	kW													2,010

Notes:
- * All ppmvd corrected to 15% O2
- ** Secondary Cooling Air Separately Exhausted

Guaranteed values are indicated by (G), or value
All other data are estimates.

FT8-3 Swift Pac (with CO Converter)
Estimated Performance and Emissions, Part-Load Data
Tampa-Electric

Configuration: Specified Liquid Fuel (ULSD), WI to 42 ppmvd NOx @ 15% O2, Sea Level Alt., 55% Ambient RH, 72-290 Generator at 60 Hz, 13.8 kV, 0.85 pf Simple-Cycle

Performance Data																
Fuel Type		Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid
Percent of Swift Pac Unit Rating	%	100	83	75	67	50	100	83	75	67	50	100	83	75	67	50
Ambient Temperature	Deg F	20	20	20	20	20	59	59	59	59	59	90	90	90	90	90
Evaporative Cooler In-Service	Yes / No	No	No	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Chiller in Service	Yes / No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Compressor Inlet Temperature	Deg F	20	20	20	20	20	52	52	52	52	52	79	79	79	79	79
Ambient Pressure	Psia	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70
Relative Humidity	%	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Inlet Loss	Inch H20	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Exhaust Loss	Inch H20	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Fuel Supply Temperature	Deg F	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
Fuel LHV	Btu/lb	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360
Fuel HHV	Btu/lb	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553
Ratio of HHV to LHV		1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065
Gross Power Output	MWe	56.065	46.534	42.049	37.564	28.033	56.167	46.619	42.125	37.632	28.084	56.020	46.497	42.015	37.533	28.010
Gross Heat Rate, HHV	Btu/kWhr	9,877	10,175	10,396	10,674	11,533	10,075	10,376	10,592	10,868	11,739	10,263	10,580	10,797	11,066	11,950
Power Island and Evap Aux Loads	kW	277	277	277	277	277	285	285	285	285	285	285	285	285	285	285
Net Power Output	MWe	55.788	46.257	41.772	37.287	27.756	55.882	46.334	41.840	37.347	27.799	55.735	46.212	41.730	37.248	27.725
Net Heat Rate, HHV	Btu/kWhr	9,926	10,236	10,465	10,753	11,648	10,126	10,440	10,665	10,951	11,860	10,315	10,645	10,870	11,151	12,073
Fuel Flow, per GT	lbs/hr	14,159	12,106	11,178	10,252	8,267	14,470	12,368	11,409	10,457	8,430	14,701	12,579	11,599	10,620	8,559
Burner Water Injection Flow, per GT	gal/min	29.6	23.6	21.1	18.6	13.7	32.2	25.9	23.1	20.5	15.1	34.3	27.7	24.8	22.0	16.3
EVAP Water Flow Rate, per GT	gal/min	0.0	0.0	0.0	0.0	0.0	2.3	2.1	2.0	1.9	1.7	3.4	3.1	3.0	2.9	2.6
Gaseous Fuel Flow @ 15C, per GT	SCF/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Emissions at GT Exit*																
NOx	ppmvd	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
NOx, as NO2, per GT	lbs/hr	49.4	42.2	38.9	35.7	28.7	50.5	43.1	39.8	36.4	29.3	51.3	43.9	40.4	37.0	29.8
VOC as C1	ppmvd	5.0	6.5	8.7	12.0	25.4	5.0	5.0	5.0	6.0	13.1	5.0	5.0	5.0	5.0	7.8
VOC as C1, per GT	lbs/hr	2.0	2.3	2.8	3.5	6.0	2.1	1.8	1.6	1.8	3.2	2.1	1.8	1.7	1.5	1.9
SO2	ppmvd	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
SO2, per GT	lbs/hr	0.47	0.40	0.37	0.34	0.27	0.48	0.41	0.38	0.35	0.28	0.49	0.42	0.38	0.35	0.28
TSP/PM10, Filterable and Cond, per GT	lbs/hr	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Exhaust Gas Flow, per GT **	lbs/sec	205	190	182	173	154	197	182	174	166	147	190	175	168	160	142
Exhaust Gas Temperature **	Deg F	793	758	744	731	699	864	828	814	799	767	921	887	872	856	823
Exhaust Gas Molecular Weight, Wet		28.64	28.68	28.70	28.72	28.76	28.49	28.54	28.56	28.58	28.63	28.27	28.32	28.34	28.36	28.41
Exhaust Gas Vol Flow Rate, per GT **	ACFS	6,558	5,883	5,567	5,247	4,534	6,688	5,996	5,669	5,339	4,610	6,788	6,085	5,750	5,411	4,669
Stack Exhaust Velocity, per GT **	ft/s	92.5	83.0	78.5	74.0	64.0	94.4	84.6	80.0	75.3	65.0	95.8	85.8	81.1	76.3	65.9
H2O	% Vol wet	6.85	6.16	5.86	5.56	4.88	8.41	7.69	7.37	7.04	6.31	10.63	9.90	9.57	9.22	8.45
O2	% Vol wet	14.2	14.7	14.9	15.2	15.7	13.5	14.1	14.3	14.6	15.2	12.8	13.4	13.6	13.9	14.5
CO2	% Vol wet	4.00	3.71	3.58	3.45	3.13	4.23	3.93	3.79	3.65	3.32	4.42	4.12	3.97	3.82	3.48
A	% Vol wet	0.882	0.887	0.889	0.892	0.897	0.868	0.874	0.876	0.879	0.884	0.849	0.854	0.857	0.859	0.865
N2	% Vol wet	74.1	74.5	74.7	74.9	75.3	73.0	73.4	73.6	73.8	74.3	71.3	71.8	72.0	72.2	72.7
Treated Exhaust Characteristics (Post CO Converter)*																
CO	ppmvd	2.1	2.8	3.2	3.7	5.1	2.0	2.0	2.3	2.7	3.8	2.0	2.0	2.0	2.1	3.8
CO, per GT	lbs/hr	1.5	1.7	1.8	1.9	2.1	1.5	1.3	1.4	1.4	1.6	1.5	1.3	1.2	1.1	0.6

Estimated Chiller Load Calculations

Air Enthalpy into Chiller	Btu/lb
Air Enthalpy out off Chiller	Btu/lb
Delta Enthalpy through Chiller	Btu/lb
Airflow through Chiller, per GT	pps
Air Enthalpy removed by Chiller	Btu/s
Tons of Refrigeration, per GT	ton
Chiller load, per GT	kW
Chiller load, per SP	kW

Notes:
- * All ppmvd corrected to 15% O2
- ** Secondary Cooling Air Separately Exhausted

Guaranteed values are indicated by (G), or $\boxed{\text{value}}$
All other data are estimates.

Figure 9367: 01/25/08
Tampa Electric
Est. Fuel Flow vs. Ambient Temp
FT8-3 Swift Pac, Natural Gas, 22,932 Btu/lb HHV, WI to 25 ppm NOx
Sea Level, 55 %RH, 3.1 inch H20 inlet loss, 6.0 inch exhaust loss

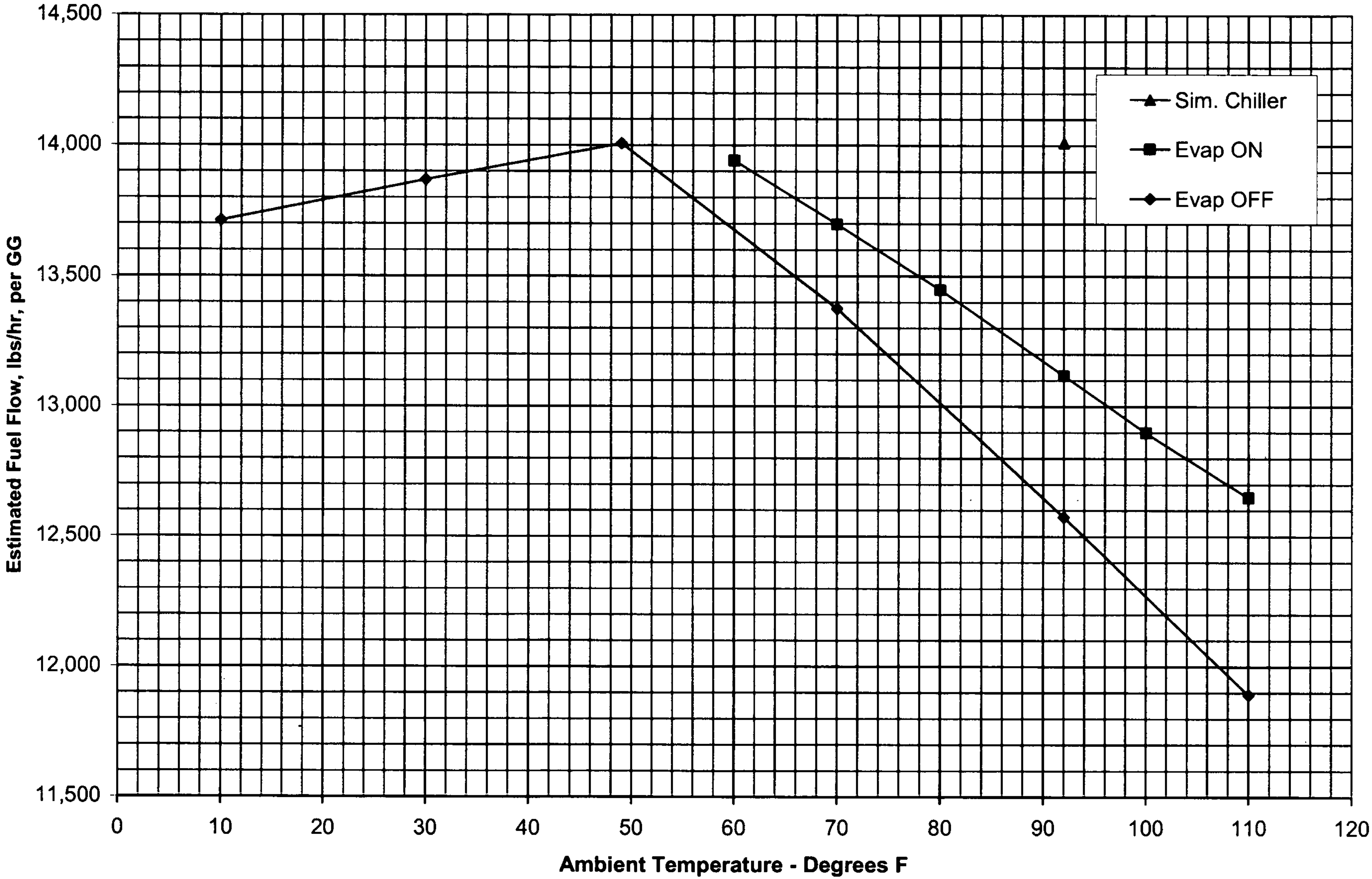

Figure 9368: 01/25/08
Tampa Electric
Est. Fuel Flow vs. Ambient Temp
FT8-3 Swift Pac, Specified Liquid Fuel (ULSD), 19,553 Btu/lb HHV, WI to 42 ppm NOx,
Sea Level, 55 %RH, 3.1 inch H20 inlet loss, 6.0 inch exhaust loss