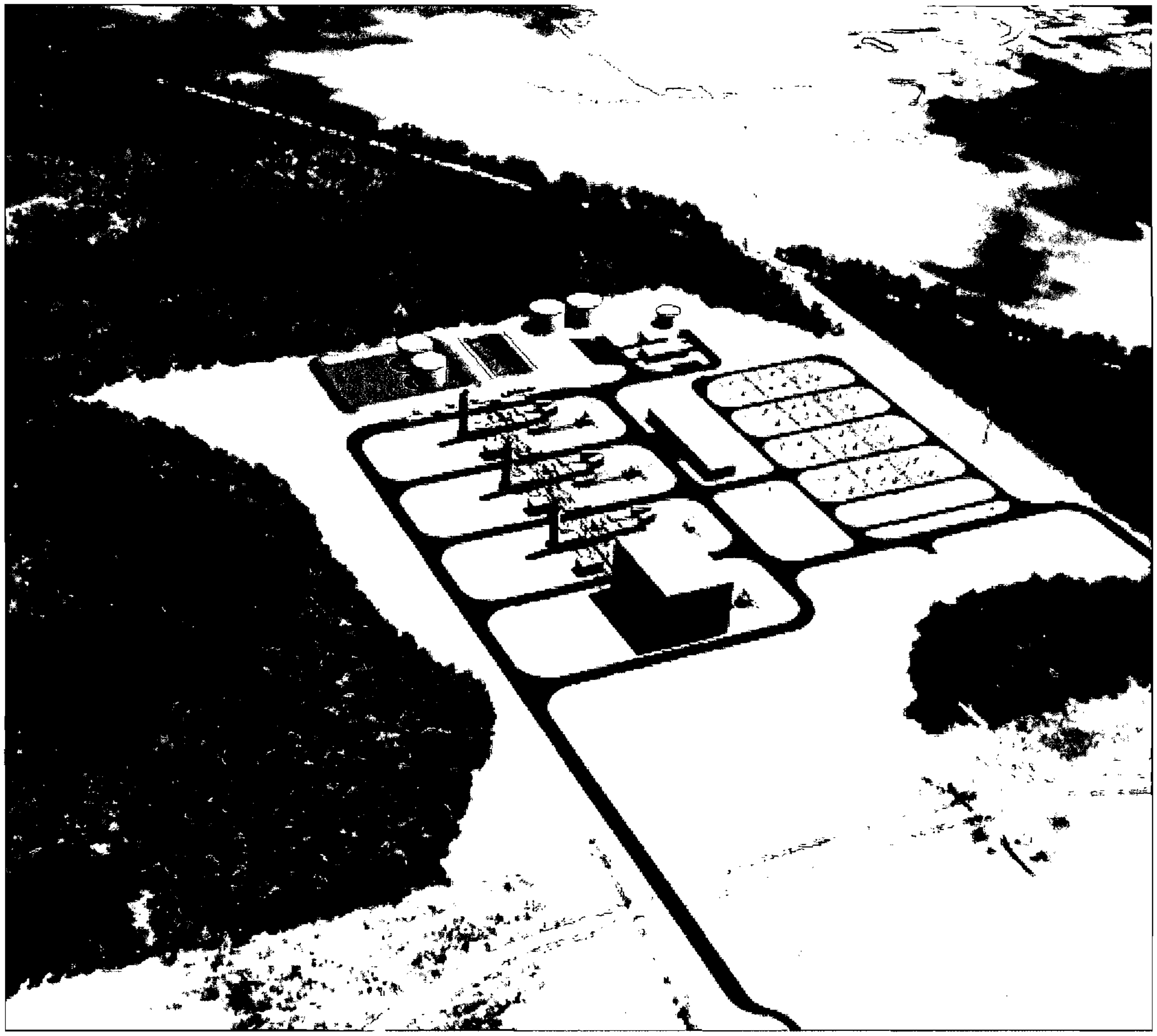
# TITLE V AIR PERMIT APPLICATION



# JEA Brandy Branch Simple Cycle Project

JEA

Building Community

21 West Church Street
Jacksonville, Florida 32202-3139

RECEIVED
SEP 14 2001
BUREAU OF AIR REGULATION

JEA

ELECTRIC
WATER
SEWER

September 13, 2001

Clair H. Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Brandy Branch Generating Station
Permit No. 0310485-004-AC, PSD-FL-267

Dear Mr. Fancy:

I am enclosing an original and three (3) copies of our application for a Title V Operating Permit for our Brandy Branch Generating Station.

If you have any questions with regard to this matter, please do not hesitate to contact me at (904) 665-6247.

Sincerely,

N. Bert Gianazza, P.E.
Environmental Permitting
& Compliance Group

Enclosure

# JEA
# BRANDY BRANCH GENERATING STATION
Jacksonville, Florida

## Florida Department of Environmental Protection
## Title V Air Permit Application

Submitted

September 2001

Prepared by

Black & Veatch Corporation
11401 Lamar Ave
Overland Park, Kansas 66211

# Department of Environmental Protection

## Division of Air Resources Management

## APPLICATION FOR AIR PERMIT - TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

### I. APPLICATION INFORMATION

**Identification of Facility**

| | |
|---|---|
| 1. Facility Owner/Company Name:<br>JEA | |
| 2. Site Name:<br>Brandy Branch Generating Station | |
| 3. Facility Identification Number: 0310485 [ ] Unknown | |
| 4. Facility Location:<br>JEA<br>Brandy Branch Generating Station<br>Located<br>Street Address or Other Locator:<br>City: Baldwin City County: Duval Zip Code: 32234 | |
| 5. Relocatable Facility?<br>[ ] Yes [X] No | 6. Existing Permitted Facility?<br>[X] Yes [ ] No |

**Application Contact**

| |
|---|
| 1. Name and Title of Application Contact:<br><br>Name: N. Bert Gianazza, P.E.<br><br>Title : Environmental Health and Safety Group |
| 2. Application Contact Mailing Address:<br><br>Organization/Firm: JEA<br>Street Address: 21 West Church Street, Tower 8<br>City: Jacksonville State: FL Zip Code: 32202-3139 |
| 3. Application Contact Telephone Numbers:<br>Telephone: (904 ) 665 - 6247 Fax: (904) 665 - 7376 |

**Application Processing Information (DEP Use)**

| | |
|---|---|
| 1. Date of Receipt of Application: | |
| 2. Permit Number: | |
| 3. PSD Number (if applicable): | |
| 4. Siting Number (if applicable): | |

## Purpose of Application

### Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number: ____________________

[ X ] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number: 0310485-004-AC, PSD-FL-267

Operation permit number to be revised: ____________________

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected: ____________________

[ ] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised: ____________________

Reason for revision: ____________________

### Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

**Owner/Authorized Representative or Responsible Official**

| | |
|---|---|
| 1. | Name and Title of Owner/Authorized Representative or Responsible Official:<br>Walter P. Bussells,<br>Managing Director and CEO |
| 2. | Owner/Authorized Representative or Responsible Official Mailing Address:<br>Organization/Firm: JEA<br>Street Address: 21 West Church Street<br>City: Jacksonville State: FL Zip Code: 32202-3139 |
| 3. | Owner/Authorized Representative or Responsible Official Telephone Numbers:<br>Telephone: (904 ) 665-7220 Fax: (904 ) 665-7366 |
| 4. | Owner/Authorized Representative or Responsible Official Statement:<br>*I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [ ], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.*<br><br>Signature 9/13/01 Date |

* Attach letter of authorization if not currently on file.

**Professional Engineer Certification**

| | |
|---|---|
| 1. | Professional Engineer Name: Charles J. Schutty<br>Registration Number: 43646 |
| 2. | Professional Engineer Mailing Address:<br>Organization/Firm: Black & Veatch Corporation<br>Street Address 8400 Ward Parkway<br>City: State:Zip Code: Kansas City, MO 64114 |
| 3. | Professional Engineer Telephone Numbers:<br>Telephone: (913) 458-2369 Fax: (913) 458-2934 |

4. Professional Engineer Statement:

*I, the undersigned, hereby certify, except as particularly noted herein*, that:*

*(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and*

*(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.*

*If the purpose of this application is to obtain a Title V source air operation permit (check here [x], if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, should comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.*

*If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [ ], if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.*

*If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ], if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.*

Charles J. Schutty 43646 September 7, 2001

Signature Date

(seal)

CHARLES J. SCHUTTY CERTIFICATE NO. 43646 STATE OF FLORIDA REGISTERED ENGINEER

* Attach any exception to certification statement.

**Scope of Application**

| Emissions Unit ID | Description of Emissions Unit | Permit Type | Processing Fee |
|---|---|---|---|
| 001 | Unit 1 – 170 MW Simple Cycle Combustion Turbine-Electrical Generator | N/A | N/A |
| 002 | Unit 2 – 170 MW Simple Cycle Combustion Turbine-Electrical Generator | N/A | N/A |
| 003 | Unit 3 – 170 MW Simple Cycle Combustion Turbine-Electrical Generator | N/A | N/A |
| 004 | One Million Gallon #2 Distillate Fuel Oil Storage Tank | N/A | N/A |
| 005 | One Million Gallon #2 Distillate Fuel Oil Storage Tank | N/A | N/A |
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**Application Processing Fee**

Check one: [ ] Attached - Amount: $____________________ [ ] Not Applicable

## Construction/Modification Information

| |
|---|
| 1. Description of Proposed Project or Alterations:<br><br>JEA has constructed three nominal 170 MW natural gas and No. 2 distillate fuel oil fired simple cycle combustion turbine (SCCT) electric generating units at the existing Brandy Branch Generating Station in accordance with Air Construction Permit No.0310485-001-AC. Each unit is a General Electric PG7241FA combustion turbine.<br><br>The Brandy Branch facility consists of three simple cycle combustion turbines each permitted to operate 4,750 hours per year. |
| 2. Projected or Actual Date of Commencement of Construction: 1999 |
| 3. Projected Date of Completion of Construction: 2001 (units one and two) |

## Application Comment

Unit 1 has been completed and on-line as of April 20, 2001. Unit 2 has been completed and on-line as of April 16, 2001. Construction of Unit 3 is scheduled for completion by November 2, 2001.

## II. FACILITY INFORMATION

### A. GENERAL FACILITY INFORMATION

**Facility Location and Type**

| | | | |
|---|---|---|---|
| 1. Facility UTM Coordinates:<br>Zone: 17 East (km): 408.81 North (km): 3354.38 | | | |
| 2. Facility Latitude/Longitude:<br>Latitude (DD/MM/SS): 30 19 14 Longitude (DD/MM/SS): 81 56 55 | | | |
| 3. Governmental Facility Code:<br>4 | 4. Facility Status Code:<br>A | 5. Facility Major Group SIC Code:<br>49 | 6. Facility SIC(s):<br>4911 |
| 7. Facility Comment (limit to 500 characters):<br>Unit 1 has been completed and on-line as of April 20, 2001. Unit 2 has been completed and on-line as of April 16, 2001. Construction of Unit 3 is scheduled for completion by November 2, 2001. | | | |

**Facility Contact**

| |
|---|
| 1. Name and Title of Facility Contact:<br>N. Bert Gianazza, P.E.<br>Environmental Health and Safety. |
| 2. Facility Contact Mailing Address:<br>Organization/Firm: JEA<br>Street Address: 21 West Church Street, Tower 8<br>City : Jacksonville State: FL Zip Code: 32202-3139 |
| 3. Facility Contact Telephone Numbers:<br>Telephone: (904) 665-6247 Fax: (904) 665-7376 |

## FACILITY REGULATIONS

**Facility Regulatory Classifications**

**Check all that apply:**

| | |
|---|---|
| 1. [ ] Small Business Stationary Source? | [ ] Unknown |
| 2. [ X ] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)? | |
| 3. [ ] Synthetic Minor Source of Pollutants Other than HAPs? | |
| 4. [ ] Major Source of Hazardous Air Pollutants (HAPs)? | |
| 5. [ ] Synthetic Minor Source of HAPs? | |
| 6. [ X ] One or More Emissions Units Subject to NSPS? | |
| 7. [ ] One or More Emission Units Subject to NESHAP? | |
| 8. [ X ] Title V Source by EPA Designation? | |
| 9. Facility Regulatory Classifications Comment (limit to 200 characters): | |

**List of Applicable Regulations**

Facility wide applicable regulations hereby incorporates by reference the Title V Core List of Applicable Regulations that all Title V sources are presumptively subject.

Facility wide applicable regulations specified in Section II and III of the facility's PSD Permit, PSD-FL-267 and 0310485-004-AC are hereby incorporated by reference.

## B. FACILITY POLLUTANTS

**List of Pollutants Emitted**

| 1. Pollutant Emitted | 2. Pollutant Classif. | 3. Requested Emissions Cap lb/hour | tons/year | 4. Basis for Emissions Cap | 5. Pollutant Comment |
|---|---|---|---|---|---|
| NOX | A | | | | |
| CO | A | | | | |
| VOC | B | | | | |
| SO2 | A | | | | |
| PM/ PM10 | B | | | | |
| PB | B | | | | |
| HAPS | B | | | | |
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## C. FACILITY SUPPLEMENTAL INFORMATION

**Supplemental Requirements**

| | |
|---|---|
| 1. | Area Map Showing Facility Location:<br>[X] Attached, Document ID: Attachment A [ ] Not Applicable [ ] Waiver Requested |
| 2. | Facility Plot Plan:<br>[X] Attached, Document ID: Attachment B [ ] Not Applicable [ ] Waiver Requested |
| 3. | Process Flow Diagram(s):<br>[X] Attached, Document ID: Attachment C [ ] Not Applicable [ ] Waiver Requested |
| 4. | Precautions to Prevent Emissions of Unconfined Particulate Matter:<br>[X] Attached, Document ID: Attachment D [ ] Not Applicable [ ] Waiver Requested |
| 5. | Fugitive Emissions Identification:<br>[ ] Attached, Document ID:_______ [X] Not Applicable [ ] Waiver Requested |
| 6. | Supplemental Information for Construction Permit Application:<br>[ ] Attached, Document ID:____________ [ X] Not Applicable |
| 7. | Supplemental Requirements Comment: |

**Additional Supplemental Requirements for Title V Air Operation Permit Applications**

| | |
|---|---|
| 8. List of Proposed Insignificant Activities:<br>[ ] Attached, Document ID:________ [X] Not Applicable | |
| 9. List of Equipment/Activities Regulated under Title VI:<br>[ ] Attached, Document ID:________<br>[X] Equipment/Activities On site but Not Required to be Individually Listed<br>[ ] Not Applicable | |
| 10. Alternative Methods of Operation:<br>[ ] Attached, Document ID:________ [X] Not Applicable | |
| 11. Alternative Modes of Operation (Emissions Trading):<br>[ ] Attached, Document ID:________ [X] Not Applicable | |
| 12. Identification of Additional Applicable Requirements:<br>[ ] Attached, Document ID:________ [X] Not Applicable | |
| 13. Risk Management Plan Verification:<br>[ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________)<br>[ ] Plan to be submitted to CEPPO (Date required:________________________)<br>[X] Not Applicable | |
| 14. Compliance Report and Plan:<br>[X] Attached, Document ID: Attachment E [ ] Not Applicable | |
| 15. Compliance Certification (Hard-copy Required):<br>[X] Attached, Document ID: Attachment F [ ] Not Applicable | |

Emission unit 1



## III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

### A. GENERAL EMISSIONS UNIT INFORMATION

**(All Emissions Units)**

**Emissions Unit Description and Status**

1. Type of Emissions Unit Addressed in This Section: (Check one)

[ X ] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[ X ] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

Unit 1 – 170 MW Simple Cycle Combustion Turbine.

4. Emissions Unit Identification Number: [ ] No ID
ID: 001 [ ] ID Unknown

| 5. Emissions Unit Status Code: | 6. Initial Startup Date: | 7. Emissions Unit Major Group SIC Code: | 8. Acid Rain Unit? |
|---|---|---|---|
| C | 4/20/2001 | 49 | [ X ] |

9. Emissions Unit Comment: (Limit to 500 Characters)
The 170 MW simple cycle combustion turbine is comprised of one combustion turbine and a 90 foot exhaust stack.

Natural gas is the primary fuel; low sulfur distillate fuel oil is the back-up fuel.

Emissions will be controlled by Dry Low $NO_x$ (DLN) Combustors and water injection during fuel oil firing.

**Emissions Unit Control Equipment**

| |
|---|
| 1. Control Equipment/Method Description (Limit to 200 characters per device or method):<br><br>Dry Low $NO_x$ (DLN) Combustor.<br><br>Water injection during fuel oil firing. |
| 2. Control Device or Method Code(s): 024, 028 |

**Emissions Unit Details**

| | |
|---|---|
| 1. Package Unit: Simple cycle combustion turbine generator<br>Manufacturer: General Electric | Model Number: PG7241FA |
| 2. Generator Nameplate Rating: | 170 MW (nominal) |
| 3. Incinerator Information: N/A<br>Dwell Temperature:<br>Dwell Time:<br>Incinerator Afterburner Temperature: | <br>°F<br>seconds<br>°F |

## B. EMISSIONS UNIT CAPACITY INFORMATION
## (Regulated Emissions Units Only)

**Emissions Unit Operating Capacity and Schedule**

| | | | |
|---|---|---|---|
| 1. Maximum Heat Input Rate: | (Natural gas firing)<br>(Fuel oil firing) | 1,623 (LHV)<br>1,822 (LHV) | MMBtu/hr<br>MMBtu/hr |
| 2. Maximum Incineration Rate: | N/A lb/hr | | tons/day |
| 3. Maximum Process or Throughput Rate: N/A | | | |
| 4. Maximum Production Rate: N/A | | | |
| 5. Requested Maximum Operating Schedule: | | | |
| For Natural Gas: | 24 hours/day<br>4,750 hours/year | | 7 days/week |
| For Fuel Oil: | 16 hours/day<br>750 hours/year | | 7 days/week |

6. Operating Capacity/Schedule Comment (limit to 200 characters):

Maximum Heat Input Rate during natural gas combustion is 1,623 MMBtu/hr, lower heating value (LHV)

Maximum heat Input Rate during No.2 oil firing is 1,822 mmBtu/hr (@ 59F 60% RH) LHV

*Maximum hours of operation on natural gas are 4,750 hr/yr and 750 hr/yr for No.2 Fuel oil.

## C. EMISSIONS UNIT REGULATIONS
## (Regulated Emissions Units Only)

**List of Applicable Regulations**

| | |
|---|---|
| 40 CFR 60, Subpart A- General Provisions | Emission unit applicable regulations hereby incorporates by reference the Title V Core List of Applicable Regulations that all Title V sources are presumptively subject. |
| 40 CFR 60, Subpart GG- Standards of Performance for Stationary Gas Turbines | |
| 40 CFR 72, Permits Regulation | |
| 40 CFR 73, Sulfur Dioxide Allowance System | |
| 40 CFR 75, Continuous Emission Monitoring | |
| 62-204.800(7)(b), Federal Regulations Adopted by Reference- Standards of Performance for New Stationary Sources | |
| 62-297.520, Stationary Sources- Emissions Monitoring | |
| Ordinance Code, City of Jacksonville (JOC), Title X, Chapter 376, Odor Control | |
| Jacksonville Environmental Protection Board (JEPB), Rule 2 Part IX, General Pollutant Emission Limiting Standards – Objectionable Odor Prohibited | |
| Ordinance Code, City of Jacksonville (JOC), Title V, Chapter 362, Air and Water Pollution | |
| | |
| | |
| | |
| | |

## D. EMISSION POINT (STACK/VENT) INFORMATION
## (Regulated Emissions Units Only)

**Emission Point Description and Type**

| | |
|---|---|
| 1. Identification of Point on Plot Plan or Flow Diagram? ID #23A on Plot Plan in Attachment B | 2. Emission Point Type Code: 1 |

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

One 90-foot vertical cylindrical exhaust stack associated with the combustion turbine

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

N/A

| | | |
|---|---|---|
| 5. Discharge Type Code: V | 6. Stack Height: 90 feet | 7. Exit Diameter: 18 feet |
| 8. Exit Temperature: 1,081 °F | 9. Actual Volumetric Flow Rate: 1,623,767 acfm | 10. Water Vapor: N/A |

| | |
|---|---|
| 11. Maximum Dry Standard Flow Rate: N/A | 12. Nonstack Emission Point Height: N/A |

13. Emission Point UTM Coordinates:

Zone:17 East (km):408.835 North (km):3,354.491

14. Emission Point Comment (limit to 200 characters):

Exit temperature and flow rate conservatively reflect worst-case combined low load and natural gas operation.

## E. SEGMENT (PROCESS/FUEL) INFORMATION
## (All Emissions Units)

**<u>Segment Description and Rate:</u>** Segment _1____ of __2___

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type) (limit to 500 characters):<br><br>Combustion turbine operating in simple cycle on natural gas. This unit is allowed to operate on natural gas for 4,750 hours per year. | | |
| 2. Source Classification Code (SCC):<br>20100201 | 3. SCC Units:<br>Million Cubic Feet Burned (all gaseous fuel) | |
| 4. Maximum Hourly Rate:<br>1.59 | 5. Maximum Annual Rate:<br>7,758.09 | 6. Estimated Annual Activity Factor: N/A |
| 7. Maximum % Sulfur:<br>N/A | 8. Maximum % Ash:<br>N/A | 9. Million Btu per SCC Unit:<br>1,020 |
| 10. Segment Comment (limit to 200 characters):<br><br>Maximum Hourly Rate = $\frac{\text{1,623mmBtu/hr}}{\text{1,020 mmBtu/mmscf}}$ = 1.59 mmscf/hr<br><br>Maximum Annual Rate = $\frac{\text{4,750 hrs/yr x 1,623 mmBtu/hr}}{\text{1,020 mmBtu/mmscsf}}$ = 7,558.09 mmscf/hr | | |

**<u>Segment Description and Rate:</u>** Segment _2____ of ___2__

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type ) (limit to 500 characters):<br><br>Combustion turbine operating in simple cycle mode on No. 2 distillate fuel oil. Unit 1 will operate on No.2 distillate fuel oil for 750 hours per year and no more than 16 hours per day. | | |
| 2. Source Classification Code (SCC):<br>20100101 | 3. SCC Units:<br>Thousand Gallons Burned (all liquid fuels) | |
| 4. Maximum Hourly Rate:<br>13.11 | 5. Maximum Annual Rate:<br>9,830.94 | 6. Estimated Annual Activity Factor: N/A |
| 7. Maximum % Sulfur:<br>0.05 | 8. Maximum % Ash:<br>N/A | 9. Million Btu per SCC Unit:<br>139 |
| 10. Segment Comment (limit to 200 characters):<br><br>Maximum Hourly Rate = $\frac{\text{1,822 mmBtu/hr}}{\text{139 mmBtu/thousand gallons}}$ = 13.11 thousand gallons/hr<br><br>Maximum Annual Rate = $\frac{\text{750 hrs/yr x 1,822 mmBtu/hr}}{\text{139 mmBtu/thousand gallons}}$ = 9,830.94 thousand gallons/yr | | |

## F. EMISSIONS UNIT POLLUTANTS
**(All Emissions Units)**

| 1. Pollutant Emitted | 2. Primary Control Device Code | 3. Secondary Control Device Code | 4. Pollutant Regulatory Code |
|---|---|---|---|
| NOX | 024 | 028 | EL |
| CO | | | EL |
| VOC | | | EL |
| SO2 | | | EL |
| PM/ PM10 | | | EL |
| PB | | | EL |
| HAPS | | | NS |
| | | | |
| | | | |
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| | | | |

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
## (Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

**Potential/Fugitive Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: NOX | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions:<br>Natural Gas Firing 69.3 lb/hour 164.59 tons/year<br>*Fuel Oil Firing 318 lb/hour 119.25 tons/year<br>*Based on performance data from GE for base load at 59F | 4. Synthetically Limited? [ ] |
| 5. Range of Estimated Fugitive Emissions:<br>[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year | |
| 6. Emission Factor: | 7. Emissions Method Code:<br>0 |
| 8. Calculation of Emissions (limit to 600 characters):<br><br>Potential annual emissions:<br>Natural Gas Firing:<br>69.3 lb/hr * 4,750 hr/yr * 1/ 2,000 lb = 164.59 tons per year<br>Fuel Oil Firing:<br>318 lb/hr * 750 hr/yr* 1/ 2,000 lb = 119.25 tons per year | |
| 9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): | |

**Allowable Emissions** Allowable Emissions _1____ of __4____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code:<br>OTHER | 2. Future Effective Date of Allowable Emissions: N/A |
| 3. Requested Allowable Emissions and Units:<br>9 ppmvd ( at 15% $O_2$ for Natural Gas ) | 4. Equivalent Allowable Emissions:<br>59.4 lb/hour 141.08 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Initial Stack testing<br>- CEMS (CEMS used in lieu of water/fuel ratio 40 CFR 60.33(C)(1)) | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>9 ppmvd (at 15% $O_2$ for Natural Gas) is a First Fire requirement to be demonstrated by the "new and clean" GE performance stack test per Permit Condition #21 in PSD-FL-267. | |

**Allowable Emissions** Allowable Emissions __2___ of ___4___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: OTHER | 2. Future Effective Date of Allowable Emissions: N/A |
| 3. Requested Allowable Emissions and Units: 10.5 ppmvd ( at 15% $O_2$ for Natural Gas ) | 4. Equivalent Allowable Emissions: 69.3 lb/hour 164.59 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Annual Stack testing or RATA<br>- CEMS (CEMS used in lieu of water/fuel ratio 40 CFR 60.33(C)(1)) | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>4,750 hours/yr of Natural gas firing<br>10.5 ppmvd is the ISO condition requirement per Permit Condition #21 in PSD-FL-267. | |

**Allowable Emissions** Allowable Emissions _3____ of __4____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: 42 ppmvd (at 15% $O_2$ for Fuel Oil) | 4. Equivalent Allowable Emissions: 318 lb/hour 119.25 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Initial Stack Testing<br>- Annual Stack testing or RATA<br>- CEMS (CEMS used in lieu of water/fuel ratio 40 CFR 60.33(C)(1)) | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>750 hours/yr of fuel oil firing<br><br>After combustion fuel oil for at least 400 hours on any individual CT, the permittee shall prepare and submit for the Department's review and acceptance an engineering report regarding the lowest $NO_x$ emission rate that can consistently be achieved when firing distillate oil per Permit Condition #21 in PSD-Fl-276. | |

**Allowable Emissions** Allowable Emissions _4____ of __4___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: RULE | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: 75 ppmvd (at 15% $O_2$ for Natural Gas) | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance (limit to 60 characters): - NSPS 40 CFR 60.334(b) Subpart GG | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Rule: 40 CFR 60.334(b) Subpart GG- Standards of Performance for Stationary Gas Turbines. Note: the 75 ppm @ 15% $O_2$ is based on an equation in 40 CFR 60.332(a)(1). | |

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
### (Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

**Potential/Fugitive Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: CO | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions:<br>Natural Gas Firing: 48.00 lb/hour 114.00 tons/year<br>Fuel Oil Firing 65.00 lb/hour 24.38 tons/year | 4. Synthetically Limited? [ X ] |
| 5. Range of Estimated Fugitive Emissions:<br>[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year | |
| 6. Emission Factor: | 7. Emissions Method Code:<br>0 |
| 8. Calculation of Emissions (limit to 600 characters):<br><br>Potential annual emissions:<br>Natural Gas Firing:<br>48 lb/hr * 4,750 hr/yr * 1/ 2,000 lb = 114.00 tons per year<br>Fuel Oil Firing:<br>65 lb/hr * 750 hr/yr* 1/ 2,000 lb = 24.38 tons per year | |
| 9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): | |

**Allowable Emissions** Allowable Emissions _1____ of _2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code:<br>OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units:<br>48.00 lb/hour | 4. Equivalent Allowable Emissions:<br>48.00 lb/hour 114.00 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Stack testing | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>4,750 hours/yr of Natural gas firing.<br>Within 18 months after the initial compliance test on any individual CT, the permitee shall prepare and submit for the Department's review and acceptance an engineering report regarding the lowest CO emission rate that can consistently be achieved firing natural gas per Permit Condition #22 in PSD-FL-267. | |

**Allowable Emissions** Allowable Emissions _2____ of __2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: 65.00 lb/hour | 4. Equivalent Allowable Emissions: 65.00 lb/hour 24.38 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Stack testing | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>750 hours/yr of Fuel oil firing. | |

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
### (Regulated Emissions Units – Emissions-Limited and Preconstruction Review Pollutants Only)

**Potential/Fugitive Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: PM/PM10 | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions:<br>Natural Gas Firing 9 lb/hour 21.38 tons/year<br>Fuel Oil Firing 17 lb/hour 6.38 tons/year | 4. Synthetically Limited? [ ] |
| 5. Range of Estimated Fugitive Emissions:<br>[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year | |
| 6. Emission Factor: | 7. Emissions Method Code:<br>0 |
| 8. Calculation of Emissions (limit to 600 characters):<br><br>Potential annual emissions:<br>Natural Gas Firing:<br>9 lb/hr * 4,750 hr/yr * 1/ 2,000 lb = 21.38 tons per year<br>Fuel Oil Firing:<br>17 lb/hr * 750 hr/yr* 1/ 2,000 lb = 6.38 tons per year | |
| 9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): | |

**Allowable Emissions** Allowable Emissions _1____ of __1___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code:<br>OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units:<br>10% opacity* | 4. Equivalent Allowable Emissions:<br>17.00 lb/hour 6.38 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Fuel monitoring schedule.<br>- VE Limitation | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>*The applicant will assume 10% opacity limit for fuel oil firing in lieu of the 17.00 lb/hr PM limit during fuel oil firing. Opacity will be used as a surrogate for demonstrating compliance with PM limits per Permit Condition #31 in PSD-FL-267. | |

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
### (Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

**Potential/Fugitive Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: SO2 | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: 117 tons/yr | 4. Synthetically Limited? [ X ] |
| 5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year | |
| 6. Emission Factor: | 7. Emissions Method Code: 0 |
| 10. Calculation of Emissions (limit to 600 characters):<br><br>Potential annual emissions:<br><br>((750 hrs/yr * 98.2 lb/hr) + (4,000 hrs/yr * 1.1 lb/hr)) * 3) * ((1/ 2,000) = 117 tpy | |
| 11. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): | |

**Allowable Emissions** Allowable Emissions _1____ of _2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: 117 tpy | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Stack testing<br>- Firing of pipeline natural gas and 0.05% sulfur oil<br>- Fuel oil and natural gas monitoring schedule | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>4,750 hours/yr of Natural gas firing and 750 hours/yr of fuel oil firing.<br><br>117 tpy emission limit requirement per FDEP April, 2001 letter of "Intent to Issue PSD Permit Modification, PSD-FL-267." | |

<u>**Allowable Emissions**</u> Allowable Emissions : _2___ of _2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: RULE | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>– Rule: 40 CFR 60.333 Subpart GG | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>Rule: 40 CFR 60.333 Subpart GG- Standards of Performance for Stationary Gas Turbines. | |

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
### (Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

**Potential/Fugitive Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: VOC | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions:<br>Natural Gas Firing: 4.0 lb/hour 9.50 tons/year<br>Fuel Oil Firing 7.5 lb/hour 2.81 tons/year | 4. Synthetically Limited? [ X ] |
| 5. Range of Estimated Fugitive Emissions:<br>[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year | |
| 6. Emission Factor: | 7. Emissions Method Code:<br>0 |
| 12. Calculation of Emissions (limit to 600 characters):<br><br>Potential annual emissions:<br>Natural Gas Firing:<br>4.0 lb/hr * 4,750 hr/yr * 1/ 2,000 lb = 9.50 tons per year<br>Fuel Oil Firing:<br>7.5 lb/hr * 750 hr/yr* 1/ 2,000 lb = 2.81 tons per year | |
| 13. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): | |

**Allowable Emissions** Allowable Emissions _1____ of _2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code:<br>OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units:<br>4.0 lb/hour | 4. Equivalent Allowable Emissions:<br>4.0 lb/hour 9.50 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Initial Stack testing | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>4,750 hours/yr of Natural gas firing.<br><br>An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, CO emission limit will be employed as surrogate and no annual testing is required per Permit Condition #33 in PSD-FL-267. | |

**Allowable Emissions** Allowable Emissions _2____ of __2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: 7.5 lb/hour | 4. Equivalent Allowable Emissions: 7.5 lb/hour 2.81 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Initial Stack testing | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>750 hours/yr of Fuel oil firing.<br><br>An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, CO emission limit will be employed as surrogate and no annual testing is required per Permit Condition #33 in PSD-FL-267. | |

## H. VISIBLE EMISSIONS INFORMATION
## (Only Regulated Emissions Units Subject to a VE Limitation)

**Visible Emissions Limitation:** Visible Emissions Limitation ___1___ of ___1___

| | |
|---|---|
| 1. Visible Emissions Subtype: VE10 | 2. Basis for Allowable Opacity: [ ] Rule [X] Other |
| 3. Requested Allowable Opacity: Normal Conditions: 10% Exceptional Conditions: 20% Maximum Period of Excess Opacity Allowed: 6 min/hour | |
| 4. Method of Compliance: - stack testing (USEPA Method 9 Visual Determination of Opacity) | |
| 5. Visible Emissions Comment (limit to 200 characters): The applicant will use a 10% opacity limit for both natural gas and fuel oil firing in place of a lb/hr PM limit. | |

## I. CONTINUOUS MONITOR INFORMATION
## (Only Regulated Emissions Units Subject to Continuous Monitoring)

**Continuous Monitoring System:** Continuous Monitor ___1__ of ___2_

| | |
|---|---|
| 1. Parameter Code: EM | 2. Pollutant(s): NOX |
| 3. CMS Requirement: 40 CFR 75 | [X] Rule [ ] Other |
| 4. Monitor Information:<br>Manufacturer: TECO<br>Model Number: 42CHL | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment (limit to 200 characters):<br><br>CEMS QA plan in Attachment G | |

**Continuous Monitoring System:** Continuous Monitor ___2__ of ___2_

| | |
|---|---|
| 1. Parameter Code: O2 | 2. Pollutant(s): |
| 3. CMS Requirement: | [X] Rule [ ] Other |
| 4. Monitor Information:<br>Manufacturer: Servomex<br>Model Number: 1440C | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment (limit to 200 characters):<br><br>CEMS QA plan in Attachment G | |

## J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
## (Regulated Emissions Units Only)

**Supplemental Requirements**

| |
|---|
| 1. Process Flow Diagram<br>[ X ] Attached, Document ID: Attachment C [ ] Not Applicable [ ] Waiver Requested |
| 2. Fuel Analysis or Specification<br>[ X ] Attached, Document ID: Attachment H [ ] Not Applicable [ ] Waiver Requested |
| 3. Detailed Description of Control Equipment<br>[ X ] Attached, Document ID: Attachment I |
| 4. Description of Stack Sampling Facilities<br>[ X ] Attached, Document ID: Attachment J [ ] Not Applicable [ ] Waiver Requested |
| 5. Compliance Test Report<br>[ X ] Attached, Document ID: Attachment K<br>[ ] Previously submitted, Date:<br>[ ] Not Applicable |
| 6. Procedures for Startup and Shutdown<br>[ X ] Attached, Document ID: Attachment L [ ] Not Applicable [ ] Waiver Requested |
| 7. Operation and Maintenance Plan<br>[ ] Attached, Document ID:_______ [ X ] Not Applicable [ ] Waiver Requested |
| 8. Supplemental Information for Construction Permit Application<br>[ ] Attached, Document ID:_______ [ X ] Not Applicable |
| 9. Other Information Required by Rule or Statute<br>[ ] Attached, Document ID:_______ [ X] Not Applicable |
| 10. Supplemental Requirements Comment: |

**Additional Supplemental Requirements for Title V Air Operation Permit Applications**

| |
|---|
| 11. Alternative Methods of Operation<br>[ X ] Attached, Document ID: Attachment M [ ] Not Applicable |
| 12. Alternative Modes of Operation (Emissions Trading)<br>[ ] Attached, Document ID:________ [ X] Not Applicable |
| 13. Identification of Additional Applicable Requirements<br>[ ] Attached, Document ID:________ [ X] Not Applicable |
| 14. Compliance Assurance Monitoring Plan<br>[ ] Attached, Document ID:________ [ X] Not Applicable |
| 15. Acid Rain Part Application (Hard-copy Required)<br>[ X ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))<br>Attached, Document ID: Attachment N__<br>[ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)<br>Attached, Document ID:________<br>[ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)<br>Attached, Document ID:________<br>[ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)<br>Attached, Document ID:________<br>[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)<br>Attached, Document ID:________<br>[ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)<br>Attached, Document ID:________<br>[ ] Not Applicable |

Emission unit 2



## III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

### A. GENERAL EMISSIONS UNIT INFORMATION

**(All Emissions Units)**

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[ X ] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[ X ] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

Unit 2– 170 MW Simple Cycle Combustion Turbine.

4. Emissions Unit Identification Number: ID: 002 — [ ] No ID [ ] ID Unknown

| 5. Emissions Unit Status Code: | 6. Initial Startup Date: | 7. Emissions Unit Major Group SIC Code: | 8. Acid Rain Unit? |
|---|---|---|---|
| C | 4/16/2001 | 49 | [ X ] |

9. Emissions Unit Comment: (Limit to 500 Characters)

The 170 MW simple cycle combustion turbine is comprised of one combustion turbine and a 90 foot exhaust stack.

Natural gas is the primary fuel; low sulfur distillate fuel oil is the back-up fuel.

Emissions will be controlled by Dry Low $NO_x$ (DLN) Combustors and water injection during fuel oil firing.

## Emissions Unit Control Equipment

| |
|---|
| 1. Control Equipment/Method Description (Limit to 200 characters per device or method):<br><br>Dry Low $NO_x$ (DLN) Combustor.<br><br>Water injection during fuel oil firing. |
| 2. Control Device or Method Code(s): 024, 028 |

## Emissions Unit Details

| | |
|---|---|
| 1. Package Unit: Simple cycle combustion turbine generator<br>Manufacturer: General Electric | Model Number: PG7241FA |
| 2. Generator Nameplate Rating: | 170 MW (nominal) |
| 3. Incinerator Information: N/A<br>Dwell Temperature:<br>Dwell Time:<br>Incinerator Afterburner Temperature: | <br>°F<br>seconds<br>°F |

## B. EMISSIONS UNIT CAPACITY INFORMATION
## (Regulated Emissions Units Only)

**Emissions Unit Operating Capacity and Schedule**

| | | | |
|---|---|---|---|
| 1. Maximum Heat Input Rate: | (Natural gas firing)<br>(Fuel oil firing) | 1,623 (LHV)<br>1,822 (LHV) | MMBtu/hr<br>MMBtu/hr |
| 2. Maximum Incineration Rate: | N/A | lb/hr | tons/day |
| 3. Maximum Process or Throughput Rate: N/A | | | |
| 4. Maximum Production Rate: N/A | | | |
| 5. Requested Maximum Operating Schedule:<br>For Natural Gas:<br><br>For Fuel Oil: | <br>24 hours/day<br>4,750 hours/year<br>16 hours/day<br>750 hours/year | | <br>7 days/week<br><br>7 days/week |
| 6. Operating Capacity/Schedule Comment (limit to 200 characters):<br><br>Maximum Heat Input Rate during natural gas combustion is 1,623 MMBtu/hr, lower heating value (LHV)<br><br>Maximum heat Input Rate during No.2 oil firing is 1,822 mmBtu/hr (@ 59F 60% RH) LHV<br><br>*Maximum hours of operation on natural gas are 4,750 hr/yr and 750 hr/yr for No.2 Fuel oil. | | | |

## C. EMISSIONS UNIT REGULATIONS
## (Regulated Emissions Units Only)

**List of Applicable Regulations**

| | |
|---|---|
| 40 CFR 60, Subpart A- General Provisions | Emission unit applicable regulations hereby incorporates by reference the Title V Core List of Applicable Regulations that all Title V sources are presumptively subject. |
| 40 CFR 60, Subpart GG- Standards of Performance for Stationary Gas Turbines | |
| 40 CFR 72, Permits Regulation | |
| 40 CFR 73, Sulfur Dioxide Allowance System | |
| 40 CFR 75, Continuous Emission Monitoring | |
| 62-204.800(7)(b), Federal Regulations Adopted by Reference- Standards of Performance for New Stationary Sources | |
| 62-297.520, Stationary Sources- Emissions Monitoring | |
| Ordinance Code, City of Jacksonville (JOC), Title X, Chapter 376, Odor Control | |
| Jacksonville Environmental Protection Board (JEPB), Rule 2 Part IX, General Pollutant Emission Limiting Standards – Objectionable Odor Prohibited | |
| Ordinance Code, City of Jacksonville (JOC), Title V, Chapter 362, Air and Water Pollution | |
| | |
| | |
| | |
| | |

## D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

**Emission Point Description and Type**

| | | |
|---|---|---|
| 1. Identification of Point on Plot Plan or Flow Diagram? ID #23B on Plot Plan in Attachment B | | 2. Emission Point Type Code: 1 |
| 3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): One 90-foot vertical cylindrical exhaust stack associated with the combustion turbine | | |
| 4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A | | |
| 5. Discharge Type Code: V | 6. Stack Height: 90 feet | 7. Exit Diameter: 18 feet |
| 8. Exit Temperature: 1,081 °F | 9. Actual Volumetric Flow Rate: 1,623,767 acfm | 10. Water Vapor: N/A |
| 11. Maximum Dry Standard Flow Rate: N/A | | 12. Nonstack Emission Point Height: N/A |
| 13. Emission Point UTM Coordinates: Zone:17 East (km):408.774 North (km):3,354.491 | | |
| 14. Emission Point Comment (limit to 200 characters): Exit temperature and flow rate conservatively reflect worst-case combined low load and natural gas operation. | | |

## E. SEGMENT (PROCESS/FUEL) INFORMATION
## (All Emissions Units)

**Segment Description and Rate:** Segment _1____ of __2___

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type) (limit to 500 characters):<br><br>Combustion turbine operating in simple cycle on natural gas. This unit is allowed to operate on natural gas for 4,750 hours per year. | | |
| 2. Source Classification Code (SCC):<br>20100201 | 3. SCC Units:<br>Million Cubic Feet Burned (all gaseous fuel) | |
| 4. Maximum Hourly Rate:<br>1.59 | 5. Maximum Annual Rate:<br>7,758.09 | 6. Estimated Annual Activity Factor: N/A |
| 8. Maximum % Sulfur:<br>N/A | 9. Maximum % Ash:<br>N/A | 9. Million Btu per SCC Unit:<br>1,020 |
| 10. Segment Comment (limit to 200 characters):<br><br>Maximum Hourly Rate = 1,623mmBtu/hr / 1,020 mmBtu/mmscf = 1.59 mmscf/hr<br><br>Maximum Annual Rate = 4,750 hrs/yr x 1,623 mmBtu/hr / 1,020 mmBtu/mmscsf = 7,558.09 mmscf/hr | | |

**Segment Description and Rate:** Segment _2____ of ___2__

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type ) (limit to 500 characters):<br><br>Combustion turbine operating in simple cycle mode on No. 2 distillate fuel oil. Unit 1 will operate on No.2 distillate fuel oil for 750 hours per year and no more than 16 hours per day. | | |
| 2. Source Classification Code (SCC):<br>20100101 | 3. SCC Units:<br>Thousand Gallons Burned (all liquid fuels) | |
| 4. Maximum Hourly Rate:<br>13.11 | 5. Maximum Annual Rate:<br>9,830.94 | 6. Estimated Annual Activity Factor: N/A |
| 7. Maximum % Sulfur:<br>0.05 | 8. Maximum % Ash:<br>N/A | 9. Million Btu per SCC Unit:<br>139 |
| 10. Segment Comment (limit to 200 characters):<br><br>Maximum Hourly Rate = 1,822 mmBtu/hr / 139 mmBtu/thousand gallons = 13.11 thousand gallons/hr<br><br>Maximum Annual Rate = 750 hrs/yr x 1,822 mmBtu/hr / 139 mmBtu/thousand gallons = 9,830.94 thousand gallons/yr | | |

## F. EMISSIONS UNIT POLLUTANTS
### (All Emissions Units)

| 1. Pollutant Emitted | 2. Primary Control Device Code | 3. Secondary Control Device Code | 4. Pollutant Regulatory Code |
|---|---|---|---|
| NOX | 024 | 028 | EL |
| CO | | | EL |
| VOC | | | EL |
| SO2 | | | EL |
| PM/ PM10 | | | EL |
| PB | | | EL |
| HAPS | | | NS |
| | | | |
| | | | |
| | | | |
| | | | |

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
## (Regulated Emissions Units -
## Emissions-Limited and Preconstruction Review Pollutants Only)

**Potential/Fugitive Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: NOX | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions:<br>Natural Gas Firing 69.3 lb/hour 164.59 tons/year<br>*Fuel Oil Firing 318 lb/hour 119.25 tons/year<br>*Based on performance data from GE for base load at 59F | 4. Synthetically Limited? [ ] |
| 5. Range of Estimated Fugitive Emissions:<br>[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year | |
| 6. Emission Factor: | 7. Emissions Method Code:<br>0 |
| 8. Calculation of Emissions (limit to 600 characters):<br><br>Potential annual emissions:<br>Natural Gas Firing:<br>69.3 lb/hr * 4,750 hr/yr * 1/ 2,000 lb = 164.59 tons per year<br>Fuel Oil Firing:<br>318 lb/hr * 750 hr/yr* 1/ 2,000 lb = 119.25 tons per year | |
| 9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): | |

**Allowable Emissions** Allowable Emissions _1____ of __4____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code:<br>OTHER | 2. Future Effective Date of Allowable Emissions: N/A |
| 3. Requested Allowable Emissions and Units:<br>9 ppmvd ( at 15% $O_2$ for Natural Gas ) | 4. Equivalent Allowable Emissions:<br>59.4 lb/hour 141.08 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Initial Stack testing<br>- CEMS (CEMS used in lieu of water/fuel ratio 40 CFR 60.33(C)(1)) | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>9 ppmvd (at 15% $O_2$ for Natural Gas) is a First Fire requirement to be demonstrated by the "new and clean" GE performance stack test per Permit Condition #21 in PSD-FL-267. | |

**Allowable Emissions** Allowable Emissions __2___ of ___4___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: OTHER | 2. Future Effective Date of Allowable Emissions: N/A |
| 3. Requested Allowable Emissions and Units: 10.5 ppmvd ( at 15% $O_2$ for Natural Gas ) | 4. Equivalent Allowable Emissions: 69.3 lb/hour 164.59 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Annual Stack testing or RATA<br>- CEMS (CEMS used in lieu of water/fuel ratio 40 CFR 60.33(C)(1)) | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>4,750 hours/yr of Natural gas firing<br>10.5 ppmvd is the ISO condition requirement per Permit Condition #21 in PSD-FL-267. | |

**Allowable Emissions** Allowable Emissions _3____ of __4____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: 42 ppmvd (at 15% $O_2$ for Fuel Oil) | 4. Equivalent Allowable Emissions: 318 lb/hour 119.25 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Initial Stack Testing<br>- Annual Stack testing or RATA<br>- CEMS (CEMS used in lieu of water/fuel ratio 40 CFR 60.33(C)(1)) | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>750 hours/yr of fuel oil firing<br><br>After combustion fuel oil for at least 400 hours on any individual CT, the permittee shall prepare and submit for the Department's review and acceptance an engineering report regarding the lowest $NO_x$ emission rate that can consistently be achieved when firing distillate oil per Permit Condition #21 in PSD-Fl-276. | |

**Allowable Emissions** Allowable Emissions _4____ of __4____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: RULE | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: 75 ppmvd (at 15% $O_2$ for Natural Gas) | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- NSPS 40 CFR 60.334(b) Subpart GG | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br>Rule: 40 CFR 60.334(b) Subpart GG- Standards of Performance for Stationary Gas Turbines.<br>Note: the 75 ppm @ 15% $O_2$ is based on an equation in 40 CFR 60.332(a)(1). | |

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
**(Regulated Emissions Units -**
**Emissions-Limited and Preconstruction Review Pollutants Only)**

**Potential/Fugitive Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: CO | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions:<br>Natural Gas Firing: 48.00 lb/hour 114.00 tons/year<br>Fuel Oil Firing 65.00 lb/hour 24.38 tons/year | 4. Synthetically Limited? [ X ] |
| 5. Range of Estimated Fugitive Emissions:<br>[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year | |
| 6. Emission Factor: | 7. Emissions Method Code:<br>0 |
| 8. Calculation of Emissions (limit to 600 characters):<br><br>Potential annual emissions:<br>Natural Gas Firing:<br>48 lb/hr * 4,750 hr/yr * 1/ 2,000 lb = 114.00 tons per year<br>Fuel Oil Firing:<br>65 lb/hr * 750 hr/yr* 1/ 2,000 lb = 24.38 tons per year | |
| 9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): | |

**Allowable Emissions** Allowable Emissions _1____ of _2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code:<br>OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units:<br>48.00 lb/hour | 4. Equivalent Allowable Emissions:<br>48.00 lb/hour 114.00 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Stack testing | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>4,750 hours/yr of Natural gas firing.<br>Within 18 months after the initial compliance test on any individual CT, the permitee shall prepare and submit for the Department's review and acceptance an engineering report regarding the lowest CO emission rate that can consistently be achieved firing natural gas per Permit Condition #22 in PSD-FL-267. | |

**Allowable Emissions** Allowable Emissions _2____ of __2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: 65.00 lb/hour | 4. Equivalent Allowable Emissions: 65.00 lb/hour 24.38 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Stack testing | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>750 hours/yr of Fuel oil firing. | |

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
## (Regulated Emissions Units – Emissions-Limited and Preconstruction Review Pollutants Only)

**Potential/Fugitive Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: PM/PM10 | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions:<br>Natural Gas Firing 9 lb/hour 21.38 tons/year<br>Fuel Oil Firing 17 lb/hour 6.38 tons/year | 4. Synthetically Limited? [ ] |
| 5. Range of Estimated Fugitive Emissions:<br>[ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year | |
| 6. Emission Factor: | 7. Emissions Method Code:<br>0 |
| 8. Calculation of Emissions (limit to 600 characters):<br><br>Potential annual emissions:<br>Natural Gas Firing:<br>9 lb/hr * 4,750 hr/yr * 1/ 2,000 lb = 21.38 tons per year<br>Fuel Oil Firing:<br>17 lb/hr * 750 hr/yr* 1/ 2,000 lb = 6.38 tons per year | |
| 9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): | |

**Allowable Emissions** Allowable Emissions _1____ of __1___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code:<br>OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units:<br>10% opacity* | 4. Equivalent Allowable Emissions:<br>17.00 lb/hour 6.38 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Fuel monitoring schedule.<br>- VE Limitation | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>*The applicant will assume 10% opacity limit for fuel oil firing in lieu of the 17.00 lb/hr PM limit during fuel oil firing. Opacity will be used as a surrogate for demonstrating compliance with PM limits per Permit Condition #31 in PSD-FL-267. | |

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
## (Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

**Potential/Fugitive Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: SO2 | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions:<br>117 tons/yr | 4. Synthetically Limited? [ X ] |
| 5. Range of Estimated Fugitive Emissions:<br>[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year | |
| 6. Emission Factor: | 7. Emissions Method Code:<br>0 |
| 10. Calculation of Emissions (limit to 600 characters):<br><br>Potential annual emissions:<br><br>((750 hrs/yr * 98.2 lb/hr) + (4,000 hrs/yr * 1.1 lb/hr)) * 3) * ((1/ 2,000) = 117 tpy | |
| 11. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): | |

**Allowable Emissions** Allowable Emissions _1____ of _2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code:<br>OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units:<br>117 tpy | 4. Equivalent Allowable Emissions:<br>lb/hour tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Stack testing<br>- Firing of pipeline natural gas and 0.05% sulfur oil<br>- Fuel oil and natural gas monitoring schedule | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>4,750 hours/yr of Natural gas firing and 750 hours/yr of fuel oil firing.<br><br>117 tpy emission limit requirement per FDEP April, 2001 letter of "Intent to Issue PSD Permit Modification, PSD-FL-267." | |

**<u>Allowable Emissions</u>** Allowable Emissions : _2___ of _2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: RULE | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |

5. Method of Compliance (limit to 60 characters):
- Rule: 40 CFR 60.333 Subpart GG

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Rule: 40 CFR 60.333 Subpart GG- Standards of Performance for Stationary Gas Turbines.

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
**(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)**

**Potential/Fugitive Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: VOC | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions:<br>Natural Gas Firing: 4.0 lb/hour 9.50 tons/year<br>Fuel Oil Firing 7.5 lb/hour 2.81 tons/year | 4. Synthetically Limited? [ X ] |
| 5. Range of Estimated Fugitive Emissions:<br>[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year | |
| 6. Emission Factor: | 7. Emissions Method Code:<br>0 |
| 12. Calculation of Emissions (limit to 600 characters):<br><br>Potential annual emissions:<br>Natural Gas Firing:<br>4.0 lb/hr * 4,750 hr/yr * 1/ 2,000 lb = 9.50 tons per year<br>Fuel Oil Firing:<br>7.5 lb/hr * 750 hr/yr* 1/ 2,000 lb = 2.81 tons per year | |
| 13. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): | |

**Allowable Emissions** Allowable Emissions _1____ of _2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code:<br>OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units:<br>4.0 lb/hour | 4. Equivalent Allowable Emissions:<br>4.0 lb/hour 9.50 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Initial Stack testing | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>4,750 hours/yr of Natural gas firing.<br><br>An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, CO emission limit will be employed as surrogate and no annual testing is required per Permit Condition #33 in PSD-FL-267. | |

**<u>Allowable Emissions</u>** Allowable Emissions _2____ of __2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: 7.5 lb/hour | 4. Equivalent Allowable Emissions: 7.5 lb/hour 2.81 tons/year |

5. Method of Compliance (limit to 60 characters):
- Record Keeping – hours of operation per fuel type per 12 month period
- Initial Stack testing

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

750 hours/yr of Fuel oil firing.

An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, CO emission limit will be employed as surrogate and no annual testing is required per Permit Condition #33 in PSD-FL-267.

## H. VISIBLE EMISSIONS INFORMATION
## (Only Regulated Emissions Units Subject to a VE Limitation)

**<u>Visible Emissions Limitation</u>:** Visible Emissions Limitation ___1___ of ___1___

| | |
|---|---|
| 1. Visible Emissions Subtype: VE10 | 2. Basis for Allowable Opacity:<br>[ ] Rule [X] Other |
| 3. Requested Allowable Opacity:<br>Normal Conditions: 10% Exceptional Conditions: 20%<br>Maximum Period of Excess Opacity Allowed: 6 min/hour | |
| 4. Method of Compliance:<br>- stack testing (USEPA Method 9 Visual Determination of Opacity) | |
| 5. Visible Emissions Comment (limit to 200 characters):<br><br>The applicant will use a 10% opacity limit for both natural gas and fuel oil firing in place of a lb/hr PM limit. | |

## I. CONTINUOUS MONITOR INFORMATION
## (Only Regulated Emissions Units Subject to Continuous Monitoring)

**Continuous Monitoring System:** Continuous Monitor ___1__ of ___2_

| | |
|---|---|
| 1. Parameter Code: EM | 2. Pollutant(s): NOX |
| 3. CMS Requirement: 40 CFR 75 | [X] Rule [ ] Other |
| 4. Monitor Information:<br>Manufacturer: TECO<br>Model Number: 42CHL | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment (limit to 200 characters):<br><br>CEMS QA plan in Attachment G | |

**Continuous Monitoring System:** Continuous Monitor ___2__ of ___2_

| | |
|---|---|
| 1. Parameter Code: O2 | 2. Pollutant(s): |
| 3. CMS Requirement: | [X] Rule [ ] Other |
| 4. Monitor Information:<br>Manufacturer: Servomex<br>Model Number: 1440C | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment (limit to 200 characters):<br><br>CEMS QA plan in Attachment G | |

## J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
**(Regulated Emissions Units Only)**

**Supplemental Requirements**

| | |
|---|---|
| 1. Process Flow Diagram<br>[ X ] Attached, Document ID: Attachment C [ ] Not Applicable [ ] Waiver Requested | |
| 2. Fuel Analysis or Specification<br>[ X ] Attached, Document ID: Attachment H [ ] Not Applicable [ ] Waiver Requested | |
| 3. Detailed Description of Control Equipment<br>[ X ] Attached, Document ID: Attachment I | |
| 4. Description of Stack Sampling Facilities<br>[ X ] Attached, Document ID: Attachment J [ ] Not Applicable [ ] Waiver Requested | |
| 5. Compliance Test Report<br>[ X ] Attached, Document ID: Attachment K<br>[ ] Previously submitted, Date:<br>[ ] Not Applicable | |
| 6. Procedures for Startup and Shutdown<br>[ X ] Attached, Document ID: Attachment L [ ] Not Applicable [ ] Waiver Requested | |
| 7. Operation and Maintenance Plan<br>[ ] Attached, Document ID:______ [ X ] Not Applicable [ ] Waiver Requested | |
| 8. Supplemental Information for Construction Permit Application<br>[ ] Attached, Document ID:______ [ X ] Not Applicable | |
| 9. Other Information Required by Rule or Statute<br>[ ] Attached, Document ID:______ [ X] Not Applicable | |
| 10. Supplemental Requirements Comment: | |

**Additional Supplemental Requirements for Title V Air Operation Permit Applications**

| |
|---|
| 11. Alternative Methods of Operation<br>[ X ] Attached, Document ID: Attachment M [ ] Not Applicable |
| 12. Alternative Modes of Operation (Emissions Trading)<br>[ ] Attached, Document ID:________ [ X] Not Applicable |
| 13. Identification of Additional Applicable Requirements<br>[ ] Attached, Document ID:________ [ X] Not Applicable |
| 14. Compliance Assurance Monitoring Plan<br>[ ] Attached, Document ID:________ [ X] Not Applicable |
| 15. Acid Rain Part Application (Hard-copy Required)<br>[ X ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))<br>Attached, Document ID: Attachment N__<br>[ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)<br>Attached, Document ID:________<br>[ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)<br>Attached, Document ID:________<br>[ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)<br>Attached, Document ID:________<br>[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)<br>Attached, Document ID:________<br>[ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)<br>Attached, Document ID:________<br>[ ] Not Applicable |

Emission unit 3



## III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

### A. GENERAL EMISSIONS UNIT INFORMATION

**(All Emissions Units)**

Emissions Unit Description and Status

| | | | |
|---|---|---|---|
| 1. Type of Emissions Unit Addressed in This Section: (Check one)<br>[ X ] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).<br>[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.<br>[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only. | | | |
| 2. Regulated or Unregulated Emissions Unit? (Check one)<br>[ X ] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.<br>[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit. | | | |
| 3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):<br><br>Unit 3– 170 MW Simple Cycle Combustion Turbine. | | | |
| 4. Emissions Unit Identification Number:<br>ID: 003 | | | [ ] No ID<br>[ ] ID Unknown |
| 5. Emissions Unit Status Code:<br>C | 6. Initial Startup Date:<br>Projected:<br>11/02/01 | 7. Emissions Unit Major Group SIC Code:<br>49 | 8. Acid Rain Unit?<br>[ X ] |

9. Emissions Unit Comment: (Limit to 500 Characters)
The 170 MW simple cycle combustion turbine is comprised of one combustion turbine and a 90 foot exhaust stack.

Natural gas is the primary fuel; low sulfur distillate fuel oil is the back-up fuel.

Emissions will be controlled by Dry Low $NO_x$ (DLN) Combustors and water injection during fuel oil firing.

## Emissions Unit Control Equipment

| | |
|---|---|
| 1. | Control Equipment/Method Description (Limit to 200 characters per device or method):<br><br>Dry Low $NO_x$ (DLN) Combustor.<br><br>Water injection during fuel oil firing. |
| 2. | Control Device or Method Code(s): 024, 028 |

## Emissions Unit Details

| | | |
|---|---|---|
| 1. | Package Unit: Simple cycle combustion turbine generator<br>Manufacturer: General Electric | Model Number: PG7241FA |
| 2. | Generator Nameplate Rating: | 170 MW (nominal) |
| 3. | Incinerator Information: N/A<br>Dwell Temperature:<br>Dwell Time:<br>Incinerator Afterburner Temperature: | <br>°F<br>seconds<br>°F |

## B. EMISSIONS UNIT CAPACITY INFORMATION
**(Regulated Emissions Units Only)**

**Emissions Unit Operating Capacity and Schedule**

| | | | |
|---|---|---|---|
| 1. Maximum Heat Input Rate: | (Natural gas firing)<br>(Fuel oil firing) | 1,623 (LHV)<br>1,822 (LHV) | MMBtu/hr<br>MMBtu/hr |
| 2. Maximum Incineration Rate: | N/A | lb/hr | tons/day |
| 3. Maximum Process or Throughput Rate: N/A | | | |
| 4. Maximum Production Rate: N/A | | | |
| 5. Requested Maximum Operating Schedule: | | | |
| For Natural Gas: | 24 hours/day<br>4,750 hours/year | | 7 days/week |
| For Fuel Oil: | 16 hours/day<br>750 hours/year | | 7 days/week |
| 6. Operating Capacity/Schedule Comment (limit to 200 characters):<br><br>Maximum Heat Input Rate during natural gas combustion is 1,623 MMBtu/hr, lower heating value (LHV)<br><br>Maximum heat Input Rate during No.2 oil firing is 1,822 mmBtu/hr (@ 59F 60% RH) LHV<br><br>*Maximum hours of operation on natural gas are 4,750 hr/yr and 750 hr/yr for No.2 Fuel oil. | | | |

## C. EMISSIONS UNIT REGULATIONS
## (Regulated Emissions Units Only)

**List of Applicable Regulations**

| | |
|---|---|
| 40 CFR 60, Subpart A- General Provisions | Emission unit applicable regulations hereby incorporates by reference the Title V Core List of Applicable Regulations that all Title V sources are presumptively subject. |
| 40 CFR 60, Subpart GG- Standards of Performance for Stationary Gas Turbines | |
| 40 CFR 72, Permits Regulation | |
| 40 CFR 73, Sulfur Dioxide Allowance System | |
| 40 CFR 75, Continuous Emission Monitoring | |
| 62-204.800(7)(b), Federal Regulations Adopted by Reference- Standards of Performance for New Stationary Sources | |
| 62-297.520, Stationary Sources- Emissions Monitoring | |
| Ordinance Code, City of Jacksonville (JOC), Title X, Chapter 376, Odor Control | |
| Jacksonville Environmental Protection Board (JEPB), Rule 2 Part IX, General Pollutant Emission Limiting Standards – Objectionable Odor Prohibited | |
| Ordinance Code, City of Jacksonville (JOC), Title V, Chapter 362, Air and Water Pollution | |
| | |
| | |
| | |
| | |

## D. EMISSION POINT (STACK/VENT) INFORMATION
**(Regulated Emissions Units Only)**

**Emission Point Description and Type**

| | |
|---|---|
| 1. Identification of Point on Plot Plan or Flow Diagram? ID #23C on Plot Plan in Attachment B | 2. Emission Point Type Code: 1 |

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

One 90-foot vertical cylindrical exhaust stack associated with the combustion turbine

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

N/A

| | | |
|---|---|---|
| 5. Discharge Type Code: V | 6. Stack Height: 90 feet | 7. Exit Diameter: 18 feet |
| 8. Exit Temperature: 1,081 °F | 9. Actual Volumetric Flow Rate: 1,623,767 acfm | 10. Water Vapor: N/A |

| | |
|---|---|
| 11. Maximum Dry Standard Flow Rate: N/A | 12. Nonstack Emission Point Height: N/A |

13. Emission Point UTM Coordinates:

Zone:17 East (km):408.713 North (km):3,354.491

14. Emission Point Comment (limit to 200 characters):

Exit temperature and flow rate conservatively reflect worst-case combined low load and natural gas operation.

## E. SEGMENT (PROCESS/FUEL) INFORMATION
## (All Emissions Units)

**Segment Description and Rate:** Segment _1____ of __2___

1. Segment Description (Process/Fuel Type) (limit to 500 characters):

Combustion turbine operating in simple cycle on natural gas. This unit is allowed to operate on natural gas for 4,750 hours per year.

| | | |
|---|---|---|
| 2. Source Classification Code (SCC): 20100201 | 3. SCC Units: Million Cubic Feet Burned (all gaseous fuel) | |
| 4. Maximum Hourly Rate: 1.59 | 5. Maximum Annual Rate: 7,758.09 | 6. Estimated Annual Activity Factor: N/A |
| 8. Maximum % Sulfur: N/A | 9. Maximum % Ash: N/A | 9. Million Btu per SCC Unit: 1,020 |

10. Segment Comment (limit to 200 characters):

Maximum Hourly Rate = $\frac{\text{1,623mmBtu/hr}}{\text{1,020 mmBtu/mmscf}}$ = 1.59 mmscf/hr

Maximum Annual Rate = $\frac{\text{4,750 hrs/yr x 1,623 mmBtu/hr}}{\text{1,020 mmBtu/mmscsf}}$ = 7,558.09 mmscf/hr

**Segment Description and Rate:** Segment _2____ of ___2__

1. Segment Description (Process/Fuel Type ) (limit to 500 characters):

Combustion turbine operating in simple cycle mode on No. 2 distillate fuel oil. Unit 1 will operate on No.2 distillate fuel oil for 750 hours per year and no more than 16 hours per day.

| | | |
|---|---|---|
| 2. Source Classification Code (SCC): 20100101 | 3. SCC Units: Thousand Gallons Burned (all liquid fuels) | |
| 4. Maximum Hourly Rate: 13.11 | 5. Maximum Annual Rate: 9,830.94 | 6. Estimated Annual Activity Factor: N/A |
| 7. Maximum % Sulfur: 0.05 | 8. Maximum % Ash: N/A | 9. Million Btu per SCC Unit: 139 |

10. Segment Comment (limit to 200 characters):

Maximum Hourly Rate = $\frac{\text{1,822 mmBtu/hr}}{\text{139 mmBtu/thousand gallons}}$ = 13.11 thousand gallons/hr

Maximum Annual Rate = $\frac{\text{750 hrs/yr x 1,822 mmBtu/hr}}{\text{139 mmBtu/thousand gallons}}$ = 9,830.94 thousand gallons/yr

## F. EMISSIONS UNIT POLLUTANTS
## (All Emissions Units)

| 1. Pollutant Emitted | 2. Primary Control Device Code | 3. Secondary Control Device Code | 4. Pollutant Regulatory Code |
|---|---|---|---|
| NOX | 024 | 028 | EL |
| CO | | | EL |
| VOC | | | EL |
| SO2 | | | EL |
| PM/ PM10 | | | EL |
| PB | | | EL |
| HAPS | | | NS |
| | | | |
| | | | |
| | | | |
| | | | |

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
### (Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

**Potential/Fugitive Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: NOX | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions:<br>Natural Gas Firing 69.3 lb/hour 164.59 tons/year<br>*Fuel Oil Firing 318 lb/hour 119.25 tons/year<br>*Based on performance data from GE for base load at 59F | 4. Synthetically Limited? [ ] |
| 5. Range of Estimated Fugitive Emissions:<br>[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year | |
| 6. Emission Factor: | 7. Emissions Method Code:<br>0 |
| 8. Calculation of Emissions (limit to 600 characters):<br><br>Potential annual emissions:<br>Natural Gas Firing:<br>69.3 lb/hr * 4,750 hr/yr * 1/ 2,000 lb = 164.59 tons per year<br>Fuel Oil Firing:<br>318 lb/hr * 750 hr/yr* 1/ 2,000 lb = 119.25 tons per year | |
| 9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): | |

**Allowable Emissions** Allowable Emissions _1____ of __4____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code:<br>OTHER | 2. Future Effective Date of Allowable Emissions: N/A |
| 3. Requested Allowable Emissions and Units:<br>9 ppmvd ( at 15% $O_2$ for Natural Gas ) | 4. Equivalent Allowable Emissions:<br>59.4 lb/hour 141.08 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Initial Stack testing<br>- CEMS (CEMS used in lieu of water/fuel ratio 40 CFR 60.33(C)(1)) | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>9 ppmvd (at 15% $O_2$ for Natural Gas) is a First Fire requirement to be demonstrated by the "new and clean" GE performance stack test per Permit Condition #21 in PSD-FL-267. | |

**Allowable Emissions** Allowable Emissions __2___ of ___4___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: OTHER | 2. Future Effective Date of Allowable Emissions: N/A |
| 3. Requested Allowable Emissions and Units: 10.5 ppmvd ( at 15% $O_2$ for Natural Gas ) | 4. Equivalent Allowable Emissions: 69.3 lb/hour 164.59 tons/year |

5. Method of Compliance (limit to 60 characters):
- Record Keeping – hours of operation per fuel type per 12 month period
- Annual Stack testing or RATA
- CEMS (CEMS used in lieu of water/fuel ratio 40 CFR 60.33(C)(1))

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

4,750 hours/yr of Natural gas firing
10.5 ppmvd is the ISO condition requirement per Permit Condition #21 in PSD-FL-267.

**Allowable Emissions** Allowable Emissions _3____ of __4____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: 42 ppmvd (at 15% $O_2$ for Fuel Oil) | 4. Equivalent Allowable Emissions: 318 lb/hour 119.25 tons/year |

5. Method of Compliance (limit to 60 characters):
- Record Keeping – hours of operation per fuel type per 12 month period
- Initial Stack Testing
- Annual Stack testing or RATA
- CEMS (CEMS used in lieu of water/fuel ratio 40 CFR 60.33(C)(1))

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

750 hours/yr of fuel oil firing

After combustion fuel oil for at least 400 hours on any individual CT, the permittee shall prepare and submit for the Department's review and acceptance an engineering report regarding the lowest $NO_x$ emission rate that can consistently be achieved when firing distillate oil per Permit Condition #21 in PSD-Fl-276.

**Allowable Emissions** Allowable Emissions _4____ of __4____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: RULE | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: 75 ppmvd (at 15% $O_2$ for Natural Gas) | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance (limit to 60 characters): - NSPS 40 CFR 60.334(b) Subpart GG | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Rule: 40 CFR 60.334(b) Subpart GG- Standards of Performance for Stationary Gas Turbines. Note: the 75 ppm @ 15% $O_2$ is based on an equation in 40 CFR 60.332(a)(1). | |

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
## (Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

**Potential/Fugitive Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: CO | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions:<br>Natural Gas Firing: 48.00 lb/hour 114.00 tons/year<br>Fuel Oil Firing 65.00 lb/hour 24.38 tons/year | 4. Synthetically Limited? [ X ] |
| 5. Range of Estimated Fugitive Emissions:<br>[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year | |
| 6. Emission Factor: | 7. Emissions Method Code:<br>0 |
| 8. Calculation of Emissions (limit to 600 characters):<br><br>Potential annual emissions:<br>Natural Gas Firing:<br>48 lb/hr * 4,750 hr/yr * 1/ 2,000 lb = 114.00 tons per year<br>Fuel Oil Firing:<br>65 lb/hr * 750 hr/yr* 1/ 2,000 lb = 24.38 tons per year | |
| 9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): | |

**Allowable Emissions** Allowable Emissions _1____ of _2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code:<br>OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units:<br>48.00 lb/hour | 4. Equivalent Allowable Emissions:<br>48.00 lb/hour 114.00 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Stack testing | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>4,750 hours/yr of Natural gas firing.<br>Within 18 months after the initial compliance test on any individual CT, the permitee shall prepare and submit for the Department's review and acceptance an engineering report regarding the lowest CO emission rate that can consistently be achieved firing natural gas per Permit Condition #22 in PSD-FL-267. | |

**<u>Allowable Emissions</u>** Allowable Emissions _2____ of __2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: 65.00 lb/hour | 4. Equivalent Allowable Emissions: 65.00 lb/hour 24.38 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Stack testing | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>750 hours/yr of Fuel oil firing. | |

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
**(Regulated Emissions Units –**
**Emissions-Limited and Preconstruction Review Pollutants Only)**

**Potential/Fugitive Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: PM/PM10 | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions:<br>Natural Gas Firing 9 lb/hour 21.38 tons/year<br>Fuel Oil Firing 17 lb/hour 6.38 tons/year | 4. Synthetically Limited? [ ] |
| 5. Range of Estimated Fugitive Emissions:<br>[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year | |
| 6. Emission Factor: | 7. Emissions Method Code:<br>0 |
| 8. Calculation of Emissions (limit to 600 characters):<br><br>Potential annual emissions:<br>Natural Gas Firing:<br>9 lb/hr * 4,750 hr/yr * 1/ 2,000 lb = 21.38 tons per year<br>Fuel Oil Firing:<br>17 lb/hr * 750 hr/yr* 1/ 2,000 lb = 6.38 tons per year | |
| 9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): | |

**Allowable Emissions** Allowable Emissions _1____ of __1___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code:<br>OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units:<br>10% opacity* | 4. Equivalent Allowable Emissions:<br>17.00 lb/hour 6.38 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Fuel monitoring schedule.<br>- VE Limitation | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>*The applicant will assume 10% opacity limit for fuel oil firing in lieu of the 17.00 lb/hr PM limit during fuel oil firing. Opacity will be used as a surrogate for demonstrating compliance with PM limits per Permit Condition #31 in PSD-FL-267. | |

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
**(Regulated Emissions Units -**
**Emissions-Limited and Preconstruction Review Pollutants Only)**

**Potential/Fugitive Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: SO2 | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions:<br>117 tons/yr | 4. Synthetically Limited? [ X ] |
| 5. Range of Estimated Fugitive Emissions:<br>[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year | |
| 6. Emission Factor: | 7. Emissions Method Code:<br>0 |
| 10. Calculation of Emissions (limit to 600 characters):<br><br>Potential annual emissions:<br><br>((750 hrs/yr * 98.2 lb/hr) + (4,000 hrs/yr * 1.1 lb/hr)) * 3) * ((1/ 2,000) = 117 tpy | |
| 11. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): | |

**Allowable Emissions** Allowable Emissions _1____ of _2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code:<br>OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units:<br>117 tpy | 4. Equivalent Allowable Emissions:<br>lb/hour tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Stack testing<br>- Firing of pipeline natural gas and 0.05% sulfur oil<br>- Fuel oil and natural gas monitoring schedule | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>4,750 hours/yr of Natural gas firing and 750 hours/yr of fuel oil firing.<br><br>117 tpy emission limit requirement per FDEP April, 2001 letter of "Intent to Issue PSD Permit Modification, PSD-FL-267." | |

**Allowable Emissions** Allowable Emissions : _2___ of _2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: RULE | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>– Rule: 40 CFR 60.333 Subpart GG | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>Rule: 40 CFR 60.333 Subpart GG- Standards of Performance for Stationary Gas Turbines. | |

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
## (Regulated Emissions Units -
## Emissions-Limited and Preconstruction Review Pollutants Only)

**Potential/Fugitive Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: VOC | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions:<br>Natural Gas Firing: 4.0 lb/hour 9.50 tons/year<br>Fuel Oil Firing 7.5 lb/hour 2.81 tons/year | 4. Synthetically Limited? [ X ] |
| 5. Range of Estimated Fugitive Emissions:<br>[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year | |
| 6. Emission Factor: | 7. Emissions Method Code:<br>0 |
| 12. Calculation of Emissions (limit to 600 characters):<br><br>Potential annual emissions:<br>Natural Gas Firing:<br>4.0 lb/hr * 4,750 hr/yr * 1/ 2,000 lb = 9.50 tons per year<br>Fuel Oil Firing:<br>7.5 lb/hr * 750 hr/yr* 1/ 2,000 lb = 2.81 tons per year | |
| 13. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): | |

**Allowable Emissions** Allowable Emissions _1____ of _2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code:<br>OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units:<br>4.0 lb/hour | 4. Equivalent Allowable Emissions:<br>4.0 lb/hour 9.50 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Initial Stack testing | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>4,750 hours/yr of Natural gas firing.<br><br>An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, CO emission limit will be employed as surrogate and no annual testing is required per Permit Condition #33 in PSD-FL-267. | |

**Allowable Emissions** Allowable Emissions _2____ of __2___

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: OTHER | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: 7.5 lb/hour | 4. Equivalent Allowable Emissions: 7.5 lb/hour 2.81 tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>- Record Keeping – hours of operation per fuel type per 12 month period<br>- Initial Stack testing | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br>750 hours/yr of Fuel oil firing.<br>An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, CO emission limit will be employed as surrogate and no annual testing is required per Permit Condition #33 in PSD-FL-267. | |

## H. VISIBLE EMISSIONS INFORMATION
## (Only Regulated Emissions Units Subject to a VE Limitation)

**<u>Visible Emissions Limitation</u>:** Visible Emissions Limitation ___1___ of ___1___

| | |
|---|---|
| 1. Visible Emissions Subtype: VE10 | 2. Basis for Allowable Opacity: [ ] Rule [X] Other |
| 3. Requested Allowable Opacity: Normal Conditions: 10% Exceptional Conditions: 20% Maximum Period of Excess Opacity Allowed: 6 min/hour | |
| 4. Method of Compliance: - stack testing (USEPA Method 9 Visual Determination of Opacity) | |
| 5. Visible Emissions Comment (limit to 200 characters): The applicant will use a 10% opacity limit for both natural gas and fuel oil firing in place of a lb/hr PM limit. | |

# I. CONTINUOUS MONITOR INFORMATION
## (Only Regulated Emissions Units Subject to Continuous Monitoring)

**Continuous Monitoring System:** Continuous Monitor ___1__ of ___2_

| | |
|---|---|
| 1. Parameter Code: EM | 2. Pollutant(s): NOX |
| 3. CMS Requirement: 40 CFR 75 | [X] Rule [ ] Other |
| 4. Monitor Information:<br>Manufacturer: TECO<br>Model Number: 42CHL | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment (limit to 200 characters):<br><br>CEMS QA plan in Attachment G | |

**Continuous Monitoring System:** Continuous Monitor ___2__ of ___2_

| | |
|---|---|
| 1. Parameter Code: O2 | 2. Pollutant(s): |
| 3. CMS Requirement: | [X] Rule [ ] Other |
| 4. Monitor Information:<br>Manufacturer: Servomex<br>Model Number: 1440C | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment (limit to 200 characters):<br><br>CEMS QA plan in Attachment G | |

## J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
## (Regulated Emissions Units Only)

**Supplemental Requirements**

| |
|---|
| 1. Process Flow Diagram<br>[ X ] Attached, Document ID: Attachment C [ ] Not Applicable [ ] Waiver Requested |
| 2. Fuel Analysis or Specification<br>[ X ] Attached, Document ID: Attachment H [ ] Not Applicable [ ] Waiver Requested |
| 3. Detailed Description of Control Equipment<br>[ X ] Attached, Document ID: Attachment I |
| 4. Description of Stack Sampling Facilities<br>[ X ] Attached, Document ID: Attachment J [ ] Not Applicable [ ] Waiver Requested |
| 5. Compliance Test Report<br>[ X ] Attached, Document ID: Attachment K<br>[ ] Previously submitted, Date:<br>[ ] Not Applicable |
| 6. Procedures for Startup and Shutdown<br>[ X ] Attached, Document ID: Attachment L [ ] Not Applicable [ ] Waiver Requested |
| 7. Operation and Maintenance Plan<br>[ ] Attached, Document ID:_______ [ X ] Not Applicable [ ] Waiver Requested |
| 8. Supplemental Information for Construction Permit Application<br>[ ] Attached, Document ID:_______ [ X ] Not Applicable |
| 9. Other Information Required by Rule or Statute<br>[ ] Attached, Document ID:________ [ X] Not Applicable |
| 10. Supplemental Requirements Comment: |

**Additional Supplemental Requirements for Title V Air Operation Permit Applications**

| | |
|---|---|
| 11. Alternative Methods of Operation<br>[ X ] Attached, Document ID: Attachment M [ ] Not Applicable | |
| 12. Alternative Modes of Operation (Emissions Trading)<br>[ ] Attached, Document ID:________ [X] Not Applicable | |
| 13. Identification of Additional Applicable Requirements<br>[ ] Attached, Document ID:________ [X] Not Applicable | |
| 14. Compliance Assurance Monitoring Plan<br>[ ] Attached, Document ID:________ [X] Not Applicable | |
| 15. Acid Rain Part Application (Hard-copy Required)<br>[ X ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))<br>Attached, Document ID: Attachment N__<br>[ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)<br>Attached, Document ID:________<br>[ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)<br>Attached, Document ID:________<br>[ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)<br>Attached, Document ID:________<br>[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)<br>Attached, Document ID:________<br>[ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)<br>Attached, Document ID:________<br>[ ] Not Applicable | |

## III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

### A. GENERAL EMISSIONS UNIT INFORMATION

**(All Emissions Units)**

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[ X ] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[ X ] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

Unit 4 –One Million Gallon #2 Distillate Fuel Oil Storage Tank.

4. Emissions Unit Identification Number: [ ] No ID
ID: 004 [ ] ID Unknown

| 5. Emissions Unit Status Code: | 6. Initial Startup Date: | 7. Emissions Unit Major Group SIC Code: | 8. Acid Rain Unit? |
|---|---|---|---|
| C | 04/16/2001 | 49 | [ ] |

9. Emissions Unit Comment: (Limit to 500 Characters)

This No. 2 distillate fuel oil storage tank (1,000,000 gal) is reported as an emission unit because it is subject to reporting regulations based on the emissions guidelines of the New Source Performance Standards 40 CFR 60, Subpart Kb.

The tank is a vertical fixed roof design.

## Emissions Unit Control Equipment

| |
|---|
| 1. Control Equipment/Method Description (Limit to 200 characters per device or method):<br><br>N/A |
| 2. Control Device or Method Code(s): N/A |

## Emissions Unit Details

| | |
|---|---|
| 1. Package Unit: N/A<br>Manufacturer: | Model Number: |
| 2. Generator Nameplate Rating: | |
| 3. Incinerator Information: N/A<br>Dwell Temperature:<br>Dwell Time:<br>Incinerator Afterburner Temperature: | <br>°F<br>seconds<br>°F |

## D. EMISSION POINT (STACK/VENT) INFORMATION
## (Regulated Emissions Units Only)

**Emission Point Description and Type**

| | |
|---|---|
| 1. Identification of Point on Plot Plan or Flow Diagram? ID #9 on Plot Plan in Attachment B | 2. Emission Point Type Code: 1 |
| 3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): | |

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

The emission point for a vertical fixed roof storage tank is the breather valve on the dome roof.

There are two types of emissions associated with the breather valve of a vertical fixed roof storage tank as described below.

1) Storage Loss: Emissions resulting from expulsion of vapor from a tank through vapor expansion and contraction, which are the result of changes in ambient temperature and barometric pressure. (Also known as standing loss)

2) Working Loss: Emissions resulting from the filling and emptying of the storage tanks which are associated with the change in liquid level within the tank.

| | | |
|---|---|---|
| 5. Discharge Type Code: P | 6. Stack Height: N/A | 7. Exit Diameter: N/A |
| 8. Exit Temperature: 59°F | 9. Actual Volumetric Flow Rate: N/A | 10. Water Vapor: N/A |

| | |
|---|---|
| 11. Maximum Dry Standard Flow Rate: N/A | 12. Nonstack Emission Point Height: 40 feet |

13. Emission Point UTM Coordinates:

Zone: 17 East (km): 408.909 North (km): 3,354.484

14. Emission Point Comment (limit to 200 characters):

## E. SEGMENT (PROCESS/FUEL) INFORMATION
## (All Emissions Units)

**Segment Description and Rate:** Segment _1____ of __1___

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type) (limit to 500 characters):<br><br>#2 Distillate Fuel Oil Storage | | |
| 2. Source Classification Code (SCC):<br>40301019/40301021 | 3. SCC Units:<br>Thousand Gallons Stored | |
| 4. Maximum Hourly Rate:<br>N/A | 5. Maximum Annual Rate:<br>N/A | 6. Estimated Annual Activity Factor: 1,000.00 |
| 7. Maximum % Sulfur:<br>N/A | 8. Maximum % Ash:<br>N/A | 9. Million Btu per SCC Unit:<br>N/A |
| 10. Segment Comment (limit to 200 characters):<br><br>(1,000,000 gal stored) / (1,000 gal) = 1,000 capacity factor | | |

## F. EMISSIONS UNIT POLLUTANTS
## (All Emissions Units)

| 1. Pollutant Emitted | 2. Primary Control Device Code | 3. Secondary Control Device Code | 4. Pollutant Regulatory Code |
|---|---|---|---|
| VOC | | | NS |
| | | | |
| | | | |
| | | | |
| | | | |

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
## (Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

**Allowable Emissions** Allowable Emissions _1____ of __1____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: RULE | 2. Future Effective Date of Allowable Emissions: N/A |
| 3. Requested Allowable Emissions and Units: N/A | 4. Equivalent Allowable Emissions: N/A |
| 5. Method of Compliance (limit to 60 characters):<br>- As specified in 40 CFR 60.116(a) and (b), Subpart Kb. | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br><br>Rule: 40 CFR 60, Subpart Kb- Standards of Performance for Volatile Organic Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced after July 23, 1984. | |

## J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
## (Regulated Emissions Units Only)

**Supplemental Requirements**

| |
|---|
| 1. Process Flow Diagram<br>[ ] Attached, Document ID:________ [ X ] Not Applicable [ ] Waiver Requested |
| 2. Fuel Analysis or Specification<br>[ ] Attached, Document ID: ________ [ X ] Not Applicable [ ] Waiver Requested |
| 3. Detailed Description of Control Equipment<br>[ ] Attached, Document ID: ________ |
| 4. Description of Stack Sampling Facilities<br>[ ] Attached, Document ID:__________ [ X ] Not Applicable [ ] Waiver Requested |
| 5. Compliance Test Report<br>[ ] Attached, Document ID: ________<br>[ ] Previously submitted, Date:<br>[ X ] Not Applicable |
| 6. Procedures for Startup and Shutdown<br>[ ] Attached, Document ID:________ [ X ] Not Applicable [ ] Waiver Requested |
| 7. Operation and Maintenance Plan<br>[ ] Attached, Document ID:_______ [ X ] Not Applicable[ ] Waiver Requested |
| 8. Supplemental Information for Construction Permit Application<br>[ ] Attached, Document ID:_______ [ X ] Not Applicable |
| 9. Other Information Required by Rule or Statute<br>[ ] Attached, Document ID:________ [ X] Not Applicable |
| 10. Supplemental Requirements Comment: |

**Additional Supplemental Requirements for Title V Air Operation Permit Applications**

11. Alternative Methods of Operation
[ ] Attached, Document ID:________ [ X ] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
[ ] Attached, Document ID:________ [ X ] Not Applicable

13. Identification of Additional Applicable Requirements
[ ] Attached, Document ID:________ [ X ] Not Applicable

14. Compliance Assurance Monitoring Plan
[ ] Attached, Document ID:________ [ X ] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

[ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
Attached, Document ID:________

[ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
Attached, Document ID:________

[ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
Attached, Document ID:________

[ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
Attached, Document ID:________

[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
Attached, Document ID:________

[ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
Attached, Document ID:________

[ X ] Not Applicable

## III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

### A. GENERAL EMISSIONS UNIT INFORMATION

**(All Emissions Units)**

Emissions Unit Description and Status

| | | | |
|---|---|---|---|
| 1. Type of Emissions Unit Addressed in This Section: (Check one)<br>[ X ] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).<br>[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.<br>[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only. | | | |
| 2. Regulated or Unregulated Emissions Unit? (Check one)<br>[ X ] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.<br>[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit. | | | |
| 3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):<br>Unit 5 –One Million Gallon #2 Distillate Fuel Oil Storage Tank. | | | |
| 4. Emissions Unit Identification Number:<br>ID: 005 | | | [ ] No ID<br>[ ] ID Unknown |
| 5. Emissions Unit Status Code:<br>C | 6. Initial Startup Date:<br>04/16/2001 | 7. Emissions Unit Major Group SIC Code:<br>49 | 8. Acid Rain Unit?<br>[ ] |

9. Emissions Unit Comment: (Limit to 500 Characters)

This No. 2 distillate fuel oil storage tank (1,000,000 gal) is reported as an emission unit because it is subject to reporting regulations based on the emissions guidelines of the New Source Performance Standards 40 CFR 60, Subpart Kb.

The tank is a vertical fixed roof design.

**Emissions Unit Control Equipment**

| |
|---|
| 1. Control Equipment/Method Description (Limit to 200 characters per device or method):<br><br>N/A |
| 2. Control Device or Method Code(s): N/A |

**Emissions Unit Details**

| | |
|---|---|
| 1. Package Unit: N/A<br>Manufacturer: | Model Number: |
| 2. Generator Nameplate Rating: | |
| 3. Incinerator Information: N/A<br>Dwell Temperature:<br>Dwell Time:<br>Incinerator Afterburner Temperature: | <br>°F<br>seconds<br>°F |

## D. EMISSION POINT (STACK/VENT) INFORMATION
**(Regulated Emissions Units Only)**

**Emission Point Description and Type**

| | |
|---|---|
| 1. Identification of Point on Plot Plan or Flow Diagram?<br>ID #9 on Plot Plan in Attachment B | 2. Emission Point Type Code:<br>1 |

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

The emission point for a vertical fixed roof storage tank is the breather valve on the dome roof.

There are two types of emissions associated with the breather valve of a vertical fixed roof storage tank as described below.

1) Storage Loss: Emissions resulting from expulsion of vapor from a tank through vapor expansion and contraction, which are the result of changes in ambient temperature and barometric pressure. (Also known as standing loss)

2) Working Loss: Emissions resulting from the filling and emptying of the storage tanks which are associated with the change in liquid level within the tank.

| | | |
|---|---|---|
| 5. Discharge Type Code:<br>P | 6. Stack Height:<br>N/A | 7. Exit Diameter:<br>N/A |
| 8. Exit Temperature:<br>59°F | 9. Actual Volumetric Flow Rate:<br>N/A | 10. Water Vapor:<br>N/A |

| | |
|---|---|
| 11. Maximum Dry Standard Flow Rate:<br>N/A | 12. Nonstack Emission Point Height:<br>40 feet |

13. Emission Point UTM Coordinates:

Zone: 17 East (km): 408.933 North (km): 3,354.484

14. Emission Point Comment (limit to 200 characters):

## E. SEGMENT (PROCESS/FUEL) INFORMATION
## (All Emissions Units)

**Segment Description and Rate:** Segment _1____ of __1___

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type) (limit to 500 characters):<br><br>#2 Distillate Fuel Oil Storage | | |
| 2. Source Classification Code (SCC):<br>40301019/40301021 | 3. SCC Units:<br>Thousand Gallons Stored | |
| 4. Maximum Hourly Rate:<br>N/A | 5. Maximum Annual Rate:<br>N/A | 6. Estimated Annual Activity Factor: 1,000.00 |
| 7. Maximum % Sulfur:<br>N/A | 8. Maximum % Ash:<br>N/A | 9. Million Btu per SCC Unit:<br>N/A |
| 10. Segment Comment (limit to 200 characters):<br><br>(1,000,000 gal stored) / (1,000 gal) = 1,000 capacity factor | | |

## F. EMISSIONS UNIT POLLUTANTS
## (All Emissions Units)

| 1. Pollutant Emitted | 2. Primary Control Device Code | 3. Secondary Control Device Code | 4. Pollutant Regulatory Code |
|---|---|---|---|
| VOC | | | NS |
| | | | |
| | | | |
| | | | |
| | | | |

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
**(Regulated Emissions Units -**
**Emissions-Limited and Preconstruction Review Pollutants Only)**

**Allowable Emissions** Allowable Emissions _1____ of __1____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: RULE | 2. Future Effective Date of Allowable Emissions: N/A |
| 3. Requested Allowable Emissions and Units: N/A | 4. Equivalent Allowable Emissions: N/A |
| 5. Method of Compliance (limit to 60 characters):<br>- As specified in 40 CFR 60.116(a) and (b), Subpart Kb. | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br>Rule: 40 CFR 60, Subpart Kb- Standards of Performance for Volatile Organic Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced after July 23, 1984. | |

## J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
## (Regulated Emissions Units Only)

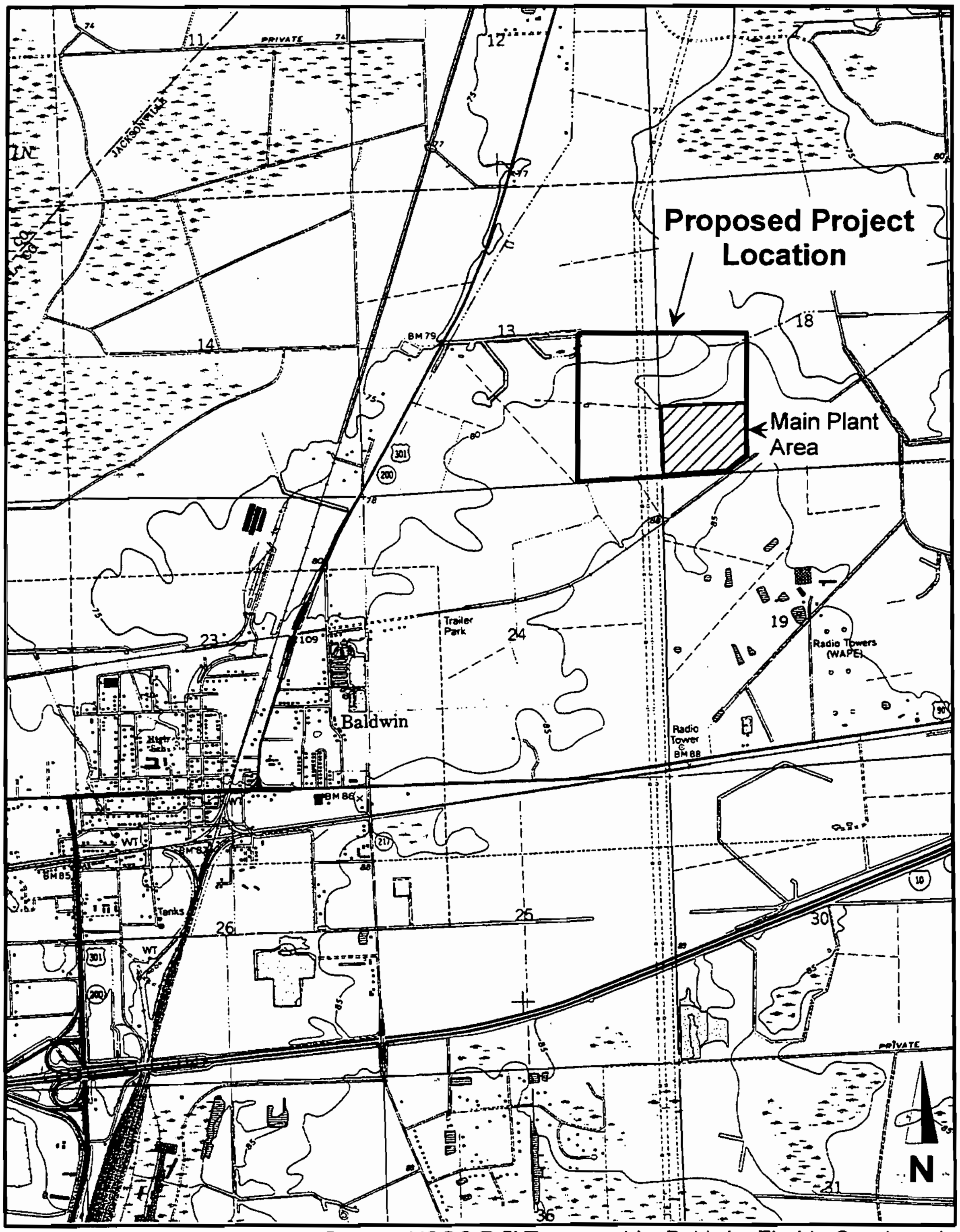
**Supplemental Requirements**

| |
|---|
| 1. Process Flow Diagram<br>[ ] Attached, Document ID:________ [ X ] Not Applicable [ ] Waiver Requested |
| 2. Fuel Analysis or Specification<br>[ ] Attached, Document ID: ________ [ X ] Not Applicable [ ] Waiver Requested |
| 3. Detailed Description of Control Equipment<br>[ ] Attached, Document ID: ________ |
| 4. Description of Stack Sampling Facilities<br>[ ] Attached, Document ID:________ [ X ] Not Applicable [ ] Waiver Requested |
| 5. Compliance Test Report<br>[ ] Attached, Document ID: ________<br>[ ] Previously submitted, Date:<br>[ X ] Not Applicable |
| 6. Procedures for Startup and Shutdown<br>[ ] Attached, Document ID:________ [ X ] Not Applicable [ ] Waiver Requested |
| 7. Operation and Maintenance Plan<br>[ ] Attached, Document ID:_______ [ X ] Not Applicable[ ] Waiver Requested |
| 8. Supplemental Information for Construction Permit Application<br>[ ] Attached, Document ID:_______ [ X ] Not Applicable |
| 9. Other Information Required by Rule or Statute<br>[ ] Attached, Document ID:________ [X] Not Applicable |
| 10. Supplemental Requirements Comment: |

**Additional Supplemental Requirements for Title V Air Operation Permit Applications**

| |
|---|
| 11. Alternative Methods of Operation<br>[ ] Attached, Document ID:________ [ X ] Not Applicable |
| 12. Alternative Modes of Operation (Emissions Trading)<br>[ ] Attached, Document ID:________ [ X ] Not Applicable |
| 13. Identification of Additional Applicable Requirements<br>[ ] Attached, Document ID:________ [ X ] Not Applicable |
| 14. Compliance Assurance Monitoring Plan<br>[ ] Attached, Document ID:________ [ X ] Not Applicable |
| 15. Acid Rain Part Application (Hard-copy Required)<br>[ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))<br>Attached, Document ID:________<br>[ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)<br>Attached, Document ID:________<br>[ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)<br>Attached, Document ID:________<br>[ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)<br>Attached, Document ID:________<br>[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)<br>Attached, Document ID:________<br>[ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)<br>Attached, Document ID:________<br>[ X ] Not Applicable |

# Attachment A
# Area Map

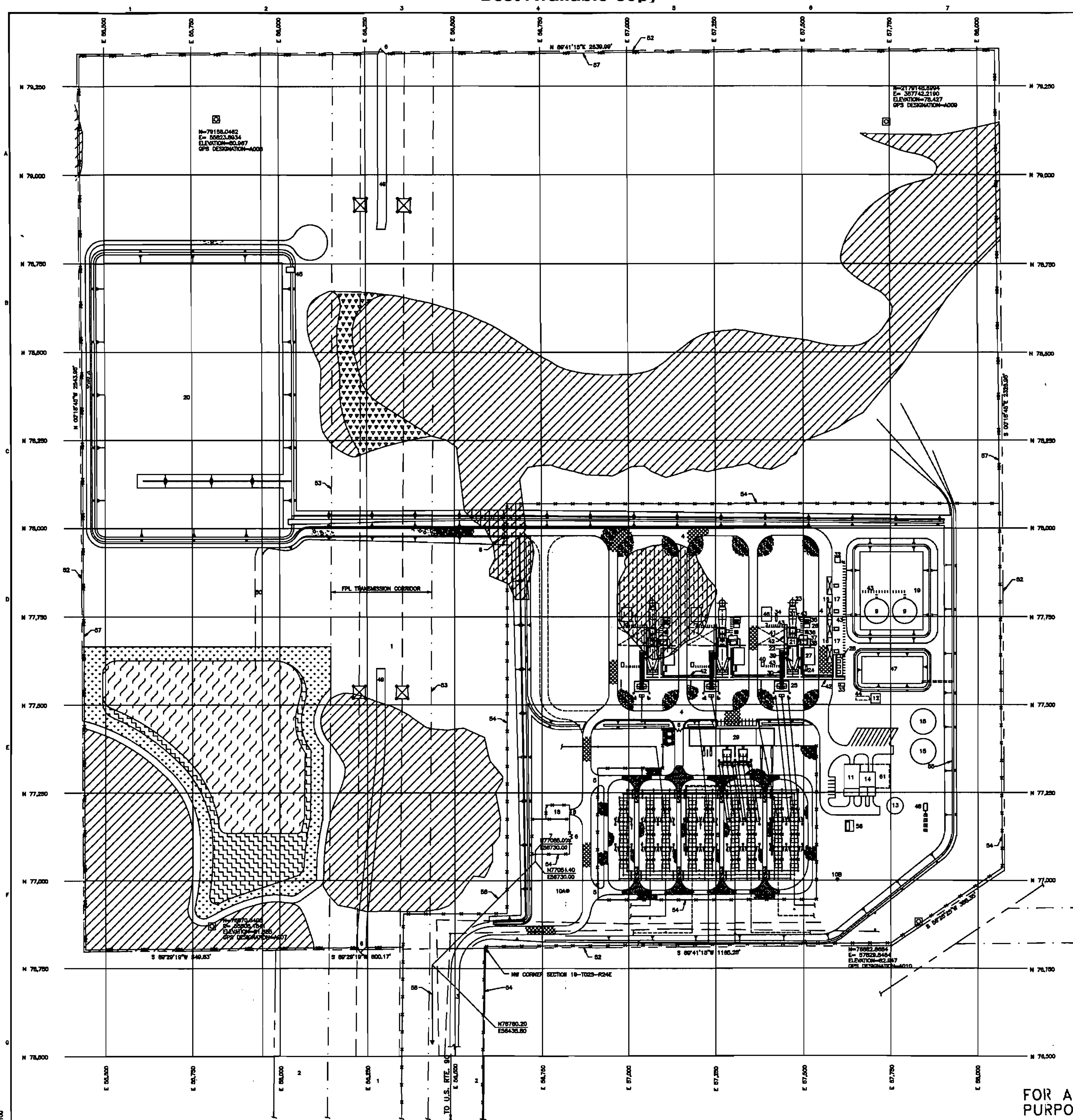


Source: USGS 7.5' Topographic, Baldwin, Florida Quadrangle

# Proposed Project Location

# Attachment B
# Facility Plot Plan

Best Available Copy




## FACILITIES LEGEND

| ITEM NO | DESCRIPTION | LOCATION COORDINATES NORTH | EAST | REFERENCE LOCATION |
|---|---|---|---|---|
| 1 | F.P.&L. RIGHT-OF-WAY | N/A | N/A | |
| 2 | JEA TRANSMISSION CORRIDOR | N/A | N/A | |
| 3 | ACCESS ROAD | N/A | N/A | SEE DWG S3202 |
| 4 | LOOP ROAD | N/A | N/A | SEE DWG S3204 |
| 5 | SLIDE GATE | N/A | N/A | SEE DWG S3205 |
| 6 | SWING GATE | N/A | N/A | SEE DWG S3205 |
| 7 | FUEL GAS METERING STATION | N/A | N/A | SEE DWG S3205 |
| 8 | SUBSTATION AREA | N/A | N/A | SEE NOTE 1 |
| 9 | FUEL OIL STORAGE TANK (1,000,000 GALLONS) | N/A | N/A | SEE M1000 SERIES DWGS |
| 10A | WATER SUPPLY WELL | 76970.00 | 56825.00 | CL WELL |
| 10B | WATER SUPPLY WELL | 77001.92 | 57097.00 | CL WELL |
| 11 | SHOP/STORAGE BUILDING | N/A | N/A | SEE M1000 SERIES DWGS |
| 12 | WASTEWATER PUMPING STATION | N/A | N/A | SEE S3300 SERIES DWGS |
| 13 | RAW WATER/FIRE WATER STORAGE TANK | N/A | N/A | SEE M1000 SERIES DWGS |
| 14 | MECHANICAL EQUIPMENT BUILDING | N/A | N/A | SEE M1000 SERIES DWGS |
| 15 | DEMINERALIZED WATER STORAGE TANK | N/A | N/A | SEE M1000 SERIES DWGS |
| 16 | FUEL OIL UNLOADING AREA | N/A | N/A | SEE M1000 SERIES DWGS |
| 17 | FUEL OIL UNLOADING PUMP AREA | N/A | N/A | SEE M1000 SERIES DWGS |
| 18 | HYDROGEN STORAGE GAS AREA | N/A | N/A | SEE DWG S3205 |
| 19 | FUEL OIL STORAGE TANK SECONDARY CONTAINMENT | N/A | N/A | SEE DWG S3002 |
| 20 | STORM WATER DETENTION POND | N/A | N/A | SEE DWG S3001 |
| 21 | COMBUSTION TURBINE (CT) | N/A | N/A | SEE M1000 SERIES DWGS |
| 22 | CT GENERATOR | N/A | N/A | SEE M1000 SERIES DWGS |
| 23 | CT EXHAUST STACK (UNIT 1) | 77788.26 | 57469.00 | CL STACK |
| 23 | CT EXHAUST STACK (UNIT 2) | 77788.26 | 57269.00 | CL STACK |
| 23 | CT EXHAUST STACK (UNIT 3) | 77788.26 | 57069.00 | CL STACK |
| 24 | CT AIR INLET FILTER | N/A | N/A | SEE M1000 SERIES DWGS |
| 25 | CT GENERATOR STEP-UP TRANSFORMER | N/A | N/A | SEE M1000 SERIES DWGS |
| 26 | CT WATER INJECTION SKID | N/A | N/A | SEE M1000 SERIES DWGS |
| 27 | CONTROL/ELECTRICAL BUILDING | N/A | N/A | SEE M1000 SERIES DWGS |
| 28 | FUEL FORWARDING SKIDS | N/A | N/A | SEE E7200 SERIES DWGS |
| 29 | CONTROL/SHARED SERVICES BUILDING | N/A | N/A | SEE M1000 SERIES DWGS |
| 30 | UNIT AUXILIARY TRANSFORMER | N/A | N/A | SEE M1000 SERIES DWGS |
| 31 | EXHAUST DUCT SILENCER | N/A | N/A | SEE M1000 SERIES DWGS |
| 32 | FIRE PROTECTION FOAM HOUSE | N/A | N/A | SEE M1000 SERIES DWGS |
| 33 | WASH WATER SKID | N/A | N/A | SEE M1000 SERIES DWGS |
| 34 | MISCELLANEOUS DRAIN TANK | N/A | N/A | SEE M1000 SERIES DWGS |
| 35 | CT CO2 FIRE PROTECTION SKID | N/A | N/A | SEE M1000 SERIES DWGS |
| 36 | FALSE START DRAIN TANK | N/A | N/A | SEE M1000 SERIES DWGS |
| 37 | LIQUID FUEL/ATOMIZING AIR MODULE | N/A | N/A | SEE M1000 SERIES DWGS |
| 38 | CT ACCESSORY MODULE | N/A | N/A | SEE M1000 SERIES DWGS |
| 39 | GENERATOR COMPARTMENT | N/A | N/A | SEE M1000 SERIES DWGS |
| 40 | FIRE WATER DELUGE HOUSE | N/A | N/A | SEE M1000 SERIES DWGS |
| 41 | MAINTENANCE AREA | N/A | N/A | SEE M1000 SERIES DWGS |
| 42 | PIPE TRENCH | N/A | N/A | SEE S5000 OR M1000 SERIES DWGS |
| 43 | SLEEPER PIPE RACK | N/A | N/A | SEE S5000 OR M1000 SERIES DWGS |
| 44 | OIL WATER SEPARATOR | N/A | N/A | SEE S3300 SERIES DWGS |
| 45 | STORM WATER DETENTION POND DISCHARGE STRUCTURE | N/A | N/A | SEE DWG S3020 AND S3021 |
| 46 | COOLER | N/A | N/A | SEE M1000 SERIES DWGS |
| 47 | PERCOLATION POND | N/A | N/A | SEE DWG S3002 |
| 48 | SEPTIC TANK AND DRAINFIELD DETAIL | N/A | N/A | SEE S3300 SERIES DWGS |
| 49 | EXISTING ROAD | N/A | N/A | |
| 50 | TEMPORARY CONSTRUCTION ACCESS ROAD | N/A | N/A | |
| 51 | FUTURE WATER TREATMENT EQUIPMENT EXPANSION | N/A | N/A | |
| 52 | PROPERTY BOUNDARY | N/A | N/A | |
| 53 | EASEMENT BOUNDARY | N/A | N/A | |
| 54 | CHAIN LINK SECURITY FENCE | N/A | N/A | SEE DWG S3205 |
| 55 | PERIMETER DITCH | N/A | N/A | |
| 56 | LUBE OIL STORAGE AREA | N/A | N/A | SEE M1000 SERIES DWGS |
| 57 | BARBED WIRE SITE PERIMETER FENCE | N/A | N/A | SEE DWG S3205 |
| 58 | TECO GAS PIPELINE | N/A | N/A | |

## GENERAL LEGEND

- BENCHMARK
- FUTURE FACILITY
- WETLANDS
- CYPRESS (ZONE 2) AREA
- ASPHALT
- CRUSHED ROCK SURFACING
- HERBACEOUS (ZONE 1) AREA
- UPLAND SEEDING AREA
- IMPACTED, DELINEATED WETLANDS
- RESTORATION MITIGATION AREA
- GEOWEB

## REFERENCE DRAWINGS

1. 60903-CMA -S3001 BUILDING & GROUNDS-SITE PREPARATION GRADING AND DRAINAGE-PLAN 1
2. 60903-CMA -S3002 BUILDING & GROUNDS-SITE PREPARATION GRADING AND DRAINAGE-PLAN 2
3. 60903-CMA -S3020 BUILDING & GROUNDS-SITE PREPARATION SECTIONS & DETAILS
4. 60903-CMA -S3021 BUILDING & GROUNDS-SITE PREPARATION SECTIONS & DETAILS
5. 60903-CMA -S3202 PLANT ACCESS ROAD PLAN & PROFILE
6. 60903-CMA -S3204 BUILDING & GROUNDS-ACCESS ROADS ROAD & SURFACING PLAN
7. 60903-CMA -S3205 SITE FENCING PLAN

## NOTES

1. FOR SUBSTATION FENCE LOCATION, SEE DWG S3205. FOR ALL EQUIPMENT/STRUCTURE LOCATIONS WITHIN THE SUBSTATION, SEE BRANDY BRANCH SUBSTATION DRAWINGS.

FOR AIR PERMITTING PURPOSES ONLY

| NO | DATE | REVISIONS AND RECORD OF ISSUE | DRN | CHK | PD | APP |
|---|---|---|---|---|---|---|
| 0 | 08-31-01 | FOR AIR PERMITTING | | | | |

SCALE: 1"=100'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA.
SIGNED ________
DATE ________ REG NO. ________

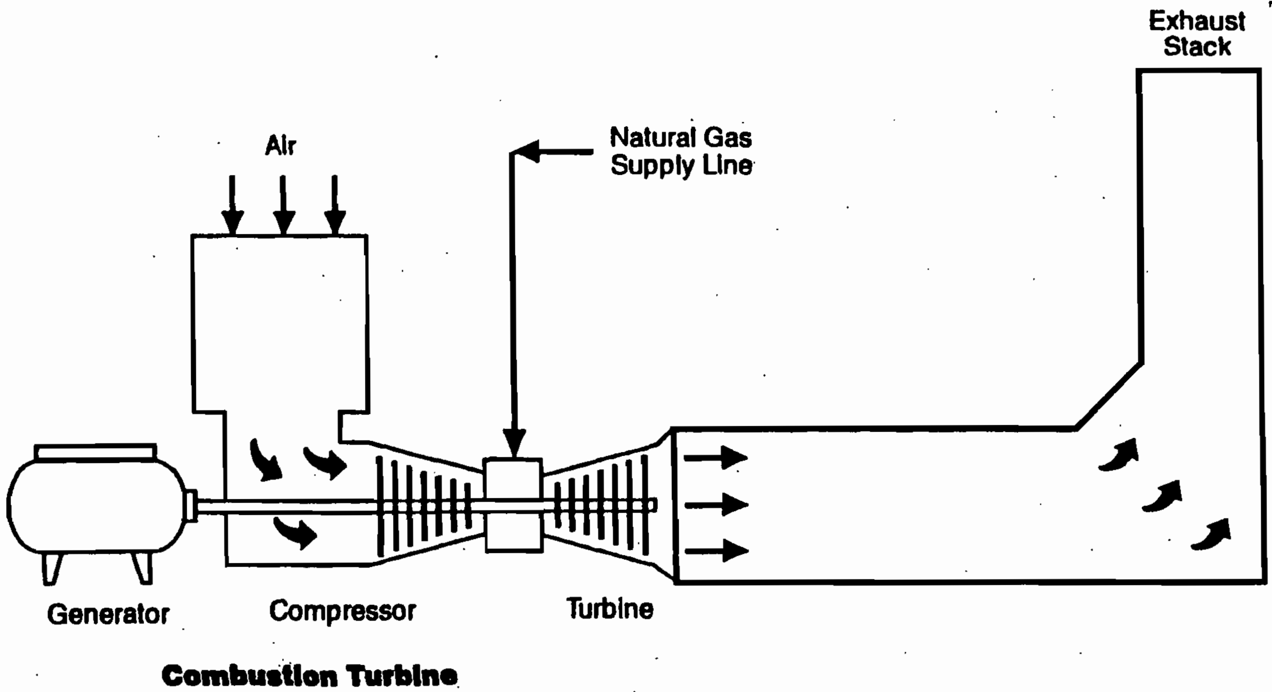
BLACK & VEATCH — JEA Building Community

JEA
BRANDY BRANCH STATION
SITE ARRANGEMENT

PROJECT / DRAWING NUMBER: 60903-CMA -S1000 REV 0

# Attachment C
# Process Flow Diagram

Simple Cycle Combustion Turbine Process Flow Diagram




SIMPLE CYCLE COMBUSTION TURBINE

Attachment D

## Precautions to Prevent Emissions of Unconfined Particulate Matter

The faculty has negligible amounts of unconfined particulate matter as a result of the operation of the facility. Potential example of particulate matter include:

- Fugitive dust from paved and unpaved roads;
- Sandblasting abrasive material from facility maintenance activities;

Several precautions were taken to prevent emissions of particulate matter in the original design of the facility. These include:

- Paving of roads, parking areas and equipment yards;
- Landscaping and planting vegetation.

Operational measures are undertaken at the facility, which also minimize particulate emissions include:

- Maintenance of paved areas as needed;
- Regular mowing of grass and care of vegetation;
- Limiting access to plant property by unnecessary vehicles;

# Attachment E
# Compliance Report and Plan

The new simple cycle combustion turbine generators (emission units 001, 002, 003) are operating in compliance with Air Construction Permit 0310485-001-AC. The units' initial emission stack tests have been completed and the results submitted to the Jacksonville Regulatory and Environmental Services Department (RESD) and DEP's Northeast District Offices. Please refer to the following summary tables:

## USE OF THIS REPORT AND INFORMATION INCLUDED

This Report and the information contained is the property of the individual or organization named on the face hereof and may be freely distributed in its present form.

## REPORT CERTIFICATION

Technical Services, Inc. (TSI) has used its professional experience and best professional efforts in performing this compliance test. I have reviewed the results of these tests and to the best of my knowledge and belief they are true and correct.

**REPORT NO.** 0106A05

Harvey C. Gray, Jr.

HARVEY C. GRAY, JR.
DATE:

Executive Summary

On June 14 and 15, 2001 Technical Services Incorporated (TSI) conducted air emission testing on Jacksonville Electric Authority's (JEA) combustion turbine number BCT-1 located at the Brandy Branch Power Park. This test was performed in order to satisfy specific requirements as specified in the State of Florida issued air construction permit number PSD-FL-267 (0310485-001-AC). The following table presents a summary of the test results. All of the test results indicate compliance with the permit requirements.

| Parameter | Test Method | Permitted Limit | Test Results | Compliance Status |
|---|---|---|---|---|
| Oxides of Nitrogen (NOx) | USEPA Method 20 | 10.5 ppm @ 15% oxygen | 7.1 ppm @ 15% oxygen | Pass |
| Carbon Monoxide (CO) | USEPA Method 10 | 15 ppm | 1 ppm | Pass |
| Volatile Organic Compounds (VOC) | USEPA Method 25a | 2 ppm | 0 ppm | Pass |
| Visible Emissions | USEPA Method 9 | 10 % opacity | 0 % opacity | Pass |
| Flow | USEPA Method 1,2,3,3a, and 4 | N/A | 761771 scfm-dry 838163 scfm-wet | N/A |
| Oxygen | USEPA Method 3a | N/A | 13.8 % | N/A |

Executive Summary

On June 18, 2001 Technical Services Incorporated (TSI) conducted air emission testing on Jacksonville Electric Authority's (JEA) combustion turbine number BCT-2 located at the Brandy Branch Power Park. This test was performed in order to satisfy specific requirements as specified in the State of Florida issued air construction permit number PSD-FL-267 (0310485-001-AC). The following table presents a summary of the test results. All of the test results indicate compliance with the permit requirements. This test was conducted with the turbine operating at **BASE LOAD** fired with **NATURAL GAS**.

| Parameter | Test Method | Permitted Limit | Test Results | Compliance Status |
|---|---|---|---|---|
| Oxides of Nitrogen (NOx) | USEPA Method 20 | 10.5 ppm @ 15% oxygen | 6.8 ppm @ 15% oxygen | Pass |
| Carbon Monoxide (CO) | USEPA Method 10 | 15 ppm | 1 ppm | Pass |
| Volatile Organic Compounds (VOC) | USEPA Method 25a | 2 ppm | 0 ppm | Pass |
| Visible Emissions | USEPA Method 9 | 10 % opacity | 0 % opacity | Pass |
| Flow | USEPA Method 1,2,3,3a, and 4 | N/A | 821920 scfm-dry 903210 scfm-wet | N/A |
| Oxygen | USEPA Method 3a | N/A | 13.8 % | N/A |

Executive Summary

On June 22, 2001 Technical Services Incorporated (TSI) conducted air emission testing on Jacksonville Electric Authority's (JEA) combustion turbine number BCT-2 located at the Brandy Branch Power Park. This test was performed in order to satisfy specific requirements as specified in the State of Florida issued air construction permit number PSD-FL-267 (0310485-001-AC). The following table presents a summary of the test results. All of the test results indicate compliance with the permit requirements. This test was conducted with the turbine operating at **BASE LOAD** fired with **OIL.**

| **Parameter** | **Test Method** | **Permitted Limit** | **Test Results** | **Compliance Status** |
|---|---|---|---|---|
| Oxides of Nitrogen (NOx) | USEPA Method 20 | 42 ppm @ 15% oxygen | 31 ppm @ 15% oxygen | Pass |
| Carbon Monoxide (CO) | USEPA Method 10 | 20 ppm | <1 ppm | Pass |
| Volatile Organic Compounds (VOC) | USEPA Method 25a | 3.5 ppm | <1 ppm | Pass |
| Visible Emissions | USEPA Method 9 | 10 % opacity | 0 % opacity | Pass |
| Flow | USEPA Method 1,2,3,3a, and 4 | N/A | 711902 scfm-dry 805319 scfm-wet | N/A |
| Oxygen | USEPA Method 3a | N/A | 12.5 % | N/A |

Attachment F

**Compliance Certification**

"I, the undersigned, am the responsible official as defined in Chapter 62-210.200, F.A.C., of the Title V source for which this report is being submitted. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made and data contained in this report are true, accurate, and complete."

for ______________________ 9/13/01
Signature Date

# Attachment G
# CEMS QA Plan

# Continuous Emissions Monitoring Systems

## Quality Assurance Plan
40 CFR 75

**Jacksonville Electric Authority**
**Brandy Branch Generating Station**
**Baldwin City, Florida**

**Prepared By:**

**KVB-Enertec, Inc.**
**30191 Avenida de las Banderas, Suite B**
**Rancho Santa Margarita, California 92688-2144**

*KVB-Enertec, Inc.*

**April 2001**
**Revision Number: 0**
**EN-3192**

# TABLE OF CONTENTS

## LIST OF TABLES

# NOTICES TO CUSTOMER

CEMSCAN® is a registered trademark of KVB-Enertec, Inc.

NTDAHS® and FOCUS 2.1® are registered trademarks of KVB-Enertec, Inc.

Product names referenced in this manual are trademarks of their respective manufacturers.

The information in this document has been carefully compiled and edited. While this material is believed to be accurate, no responsibility is assumed for possible inaccuracies or omissions.

---

Always close the door to the shelter/cabinet when not in use. Temperature changes in the shelter/cabinet can adversely affect the accuracy of the analyzers.

Never smoke in the shelter/cabinet. Cigarette smoke will interfere with the normal operations of the analyzers.

Never eat or drink when in the shelter. Any liquid or food that comes in contact with the equipment can impede performance (i.e. computer keyboards).

Never turn off or disable any piece of equipment unless proper authorization is obtained.

Always keep the shelter/cabinet free from debris. The accumulation of dust, dirt, and garbage can lead to equipment malfunction or failure.

Never load unauthorized software on the computer hard drive.

Ensure that the printer paper is in proper alignment with the printer.

Never stack any material in front of the analyzers. This could result in various problems including, but not limited to analyzer overheating and reduced air circulation.

**Caution**

To avoid equipment damage, personnel should read this manual and all manufacturers' manuals prior to operation of the CEMS.

**Caution**

Instrument power should be turned off before attempting to service or remove any printed circuit boards from any analyzer.

**Warning**

Equipment servicing can present hazards (electrical power at 208 VAC and 120 VAC is present when the CEMS is powered up) that may cause death or injury to personnel. Qualified personnel must perform servicing.

# SAFETY PROCEDURES FOR HIGH PRESSURE GAS CYLINDERS

1. Avoid rough handling of cylinders. Do not drop them or allow them to strike each other.
2. The cylinders should always be secured in an approved rack system whenever the bottles are not being used.
3. Whenever possible, store cylinders in a dry enclosure to protect them from extremes of weather and ground moisture. Do not subject cylinders to temperatures higher than 125°F. Storage of calibration gas bottles requires a secure and safe installation as defined by federal and state regulations.
4. Do not allow any part of the cylinder to come in contact with an open flame. Do not allow an arc of an electric arc welder to strike any part of the gas cylinder.
5. Do not remove the valve protection cap until the cylinder has been secured and is ready for use. Do not tamper with any part of the cylinder valve.
6. Use a hand-truck to move cylinders, even for a short distance. Do not drag; roll or slide cylinders.
7. Do not place a cylinder where it may become part of an electric circuit.
8. Per the EPA, **a compressed gas calibration standard should not be used when its gas pressure is below 1.03 megapascals (150 psig)**. NIST has found that some gas mixtures have exhibited a concentration change when the cylinder pressure has fallen below this value.
9. Do not store full and empty cylinders together.
10. Do not tamper with any part of the cylinder valve.

## TECHNICAL BULLETIN

*Safe Handling of Compressed Gases*

**Gas Cylinders**

**Storage**

Store gas cylinders in an orderly, ventilated and well-lighted area away from combustible materials. It is recommended to separate the gases by type and store in assigned locations that can be readily identified. Any labels, decals or other cylinder content identification should not be altered or removed from the gas cylinder.

Storage areas should be away from sources of excessive heat, open flame or ignition and not located in closed or sub-surface areas. Outdoor storage should be above grade, dry and protected from the extremes of weather.

Arrange the cylinder storage area so that the old stock is used first. Empty cylinders should be stored separately and identified.

While in storage, cylinder valve-protection caps must be firmly in place, cylinders should be secured from falling and protected from tampering.

Appropriate fire fighting, personnel safety and first aid equipment should be available in case of emergencies. Cylinders containing flammable gases should be stored separately from oxygen cylinders or other oxidants by a minimum distance of 20 feet or a fire-resistant wall.

Follow all federal, state and local regulations concerning the storage of compressed gas cylinders.

### Handling

Always move cylinders by hand trucks or carts designed for that purpose and never transport a gas cylinder without its valve-protection cap firmly in place. Safety glasses, gloves and safety shoes should be worn when handling cylinders. During transportation, cylinders should be properly secured to prevent them from falling, dropping or striking each other.

### Usage

Before removing the valve-protection cap, gas cylinders should be properly secured by using a floor stand, wall bracket or bench bracket.

Remove the protective cap and inspect the cylinder valve for damaged threads, dirt, oil or grease. Remove any dust or dirt with a clean cloth. If oil or grease is present on the valve of a cylinder that contains oxygen or another oxidant, do not attempt to use. Such combustible substances in contact with an oxidant are explosive. Notify the nearest Scott facility of this condition and identify the cylinder to prevent usage.

## Pressure Regulators

### Inspection

Be certain that the materials of a pressure regulator are chemically compatible with the intended gas service before installation. Inspect the regulator for the proper CGA inlet connection and note the ranges of the pressure gauges. Also examine the physical condition of the regulator including its threads and fittings. Remove any dust or dirt from the regulator or cylinder valve with a clean cloth. Do not install a regulator on a cylinder valve containing oxygen or another oxidant if grease or oil is present on either. Such combustible substances in contact with an oxidant are explosive. Initiate procedures to have the equipment properly cleaned and identify the equipment to prevent usage.

### Installation

The regulator should be securely installed on the cylinder valve using the proper wrench and without forcing the connection. Do not use pipe dopes or pipe thread on cylinder valves. The regulator-adjusting knob should be turned in the full counterclockwise or closed direction. Most Scott regulators are equipped with a needle valve in the regulator output or delivery port. Turning its adjustment knob in the full clockwise direction should close this needle valve. The downstream equipment connection can then be made to the regulator output needle valve.

### Operation

The operator, protected by safety glasses, should stand to the side of the cylinder opposite the regulator and slowly open the cylinder valve until the high-pressure gauge indicates the full cylinder pressure. The regulator output needle valve can be opened after it is certain that all downstream equipment is ready.

Open the regulator by turning its adjustment knob clockwise until the desired output pressure is indicated on the delivery gauge. After this setting is made, inspect the delivery pressure gauge to make certain that the regulator is providing a constant and stable output pressure.

Check the system for leaks by closing the downstream valve, setting regulator pressure, closing the cylinder valve and turning the regulator-adjusting knob one turn counterclockwise. A decrease in the high-pressure gauge will indicate a leak in the cylinder valve inlet fitting or high-pressure gauge. A decrease in the low-pressure gauge indicates a leak in the outlet fitting, low-pressure gauge or a downstream equipment connection. Check for the exact location by using appropriate leak detection instrumentation or methods. A decrease in the high-pressure gauge occurring concurrently with an increase in the low-pressure gauge indicates a leak in the regulator seat. The regulator must then be repaired or returned to Scott for servicing.

Close the cylinder valve when the cylinder is not in use. When the downstream equipment is not being used, close the cylinder valve and open the equipment valve to remove all pressure from the regulator. Close the equipment valve and then release all tension on the regulator adjusting knob by turning it in the full counterclockwise direction.

**Removing the Service**
Close the cylinder valve fully and isolate the regulator by safely removing all gas from it. Consideration must be given to the type of gas in service and the safe removal of residual gas from the regulator or equipment. With no gas pressure in the regulator, remove all tension on the regulator-adjusting knob by turning it in the full counterclockwise direction. Remove the regulator from the cylinder valve by using the proper wrench and protect it from damage and foreign materials. Install the protection cap on the cylinder valve.

*Reprinted with permission of Scott Specialty Gas*

## RELATED REFERENCE MATERIAL LIST

*(Under separate cover)*

Refer to the following manuals for additional information.

**KVB-Enertec, Inc. Hardware Manuals**
Operation and Maintenance Manual (System Manual and Manufacturer's Manuals)

**KVB-Enertec, Inc. Software Manuals**
NTDAHS/FOCUS 2.1 User Guide

## KVB-ENERTEC, INC. CONTACTS

**KVB-Enertec, Inc. Parts,** 8:00 AM - 5:00 PM (Pacific Time), Monday - Friday

| | |
|---|---|
| Within the USA call toll free: | 1-(800) 722-3047 |
| Direct Line: | (949) 766-4010 |
| Outside the USA call: | (949) 509-8036 |
| Fax: | (949) 766-4001 |

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| | |
|---|---|
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# REVISION NOTES

| Revision No. | Revision Date | Revised Sections | Notes |
|---|---|---|---|
| 0 | April 2001 | NA | Original Publication |
| | | | |
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# 1.0 QUALITY ASSURANCE PLAN OVERVIEW

## 1.1 Introduction

The United States Environmental Protection Agency (USEPA) re-published Part 75 to Title 40 of the Code of Federal Regulations (40 CFR 75) in the Federal Register in July, 1999. According to 40 CFR 75, Appendix B a quality control program must be developed and implemented for the continuous emission monitoring systems (CEMS) and their components. This document is in compliance with these requirements.

This Quality Assurance Plan (QAP) has been developed for the gas continuous emissions monitoring systems (CEMS) for the Jacksonville Electric Authority (JEA) at the Brandy Branch Station. KVB-Enertec, Inc., the manufacturer of the CEMS system, developed the plan.

The facility, located in the town of Baldwin City, Florida is within the jurisdiction of USEPA Region 4 and the Florida Department of Environmental Protection (FDEP). The Brandy Brach facility consists of three (3) simple cycle, dual-fired combustion turbines, each rated at 170 megawatts.

## 1.2 Quality Assurance Policy

It is the policy of JEA to adhere to all applicable rules and regulations as set forth in 40 CFR 75. All necessary air emission data will be obtained in order to demonstrate compliance with data quality objectives. The QAP establishes operational procedures that will ensure data and measurements are accurate and precise. At no time will non-quality assured data be reported as valid data.

## 1.3 Definitions

This QAP establishes procedures for both Quality Control and Quality Assurance.

1. **Quality Control** (QC) is defined as the procedures, policies and corrective actions necessary to ensure product quality. QC procedures are typically routine activities. These activities include but are not limited to daily calibrations and routine maintenance.

2. **Quality Assurance** (QA) is defined as the series of checks performed to ensure the QC procedures are functioning properly. The activities include but are not limited to relative accuracy test audits.

## 1.4 Objective

The objective of the QAP is to establish a series of QA and QC activities that will provide a high level of confidence in the data reported by the CEMS. It provides guidelines for implementing QA and QC activities.

## 1.5 Scope of Quality Assurance Plan

In order to comply with the Clean Air Act Amendments (CAAA) of 1990, as determined by the United States Environmental Protection Agency (USEPA), JEA has installed three (3) Continuous Emissions Monitoring Systems (CEMS) at the Brandy Branch facility. Each CEM system utilizes dry extractive type sampling probe, sample transport system, pollutant and diluent analyzers, and a Data Acquisition and Handling System (DAHS).

QA procedures consist of a series of checks and audits that are performed on the CEMS on a predetermined as well as an "as needed" basis. The resulting assessments activate QC measures and corrective actions. After the corrective actions are performed, the data quality is again assessed. The quality of the data will determine whether the corrective actions were successful or whether further actions are required.

The following is a brief description of the type and frequency of QA/QC procedures, as outlined in the Code of Federal Regulations Title 40, Part 75 (40 CFR 75), Appendix B.

A. Daily Assessments

1. Two-point (Zero and Span) calibration drift tests for all pollutant concentration and diluent monitors.

2. If an Out-of-control event occurs as defined in Chapter 4, Table 4-1 of this document, the appropriate maintenance and corrective action(s) will be performed and the daily assessment repeated for the affected monitor.

3. Data recording and tabulation of all calibration error tests according to month, day, and magnitude.

B. Quarterly Assessments

1. Quarterly three-point linearity check for gas concentration monitors (40 CFR 75, Appendix B).

2. If an Out-of-control event occurs as defined in Chapter 5, Section 5.2.3 of this document, the appropriate maintenance and corrective action(s) will be performed and the quarter assessment repeated for the affected monitor.

C. Semi-annual or Annual QA Activities

1. Semi-annual or annual Relative Accuracy Test Audit for $NO_X/O_2$ CEMSs.

2. Bias calculation and adjustment factors for $NO_X$ monitors.

3. If an Out-of-control event occurs as defined in Chapter 5, Section 5.3.10 of this document, the appropriate maintenance and corrective action(s) will be performed and the annual assessment repeated for the affected monitor.

QC procedures are specific maintenance activities necessary to optimize the CEMS performance and reliability. These activities, as required by 40 CFR 75, Appendix B, include daily, weekly, monthly, quarterly, semi-annual and annual checks and inspections (Refer to Table 1-1). Corrective actions, such as corrective maintenance and recalibrations, are performed when limits in the 40 CFR 75, Appendix B are exceeded.

Operation and Maintenance manuals from the analyzer manufacturers were utilized in the development of QC procedures. These documents are maintained at the facility and provide detailed procedures for calibration, troubleshooting, repair, etc. for the analyzers. These documents should be utilized as a major reference source whenever maintenance activities occur.

## 1.6 Document Control

To ensure that all copies of the QAP are revised to contain current procedures, the following document control headers and footers are provided on each page:

Revision Number
Date of Revision
Section/Page Number

## 1.7 Data Recording and Reporting

The Designated Representative (DR) or Assistant Designated Representative (ADR) of a 40 CFR 7 unit, must submit an emissions report to EPA's Acid Rain Division each calendar quarter.

The DR or ADR must submit all quarterly reports to the EPA's National Computer Center mainframe computer electronically.

All hourly data that is required to be recorded and reported on an hourly basis must be recorded electronically and not be manually edited. This includes all CEM data, hourly fuel flow data and data from alternative heat input methodologies that determine heat input on an hourly basis. This data can be recorded through different DAHS components and combined at the end of the quarter. The owner/operator must provide State auditors real time access to this data. Other data, including sampling results, default rates, hourly load data, hourly operating status and long term fuel measurement data, may be recorded electronically or entered manually into the DAHS. Calculations using the raw data and missing data substitution should be performed automatically by a DAHS component.

A central CEM file is kept at the facility. The file contains QAP check forms, audit results, corrective action forms, and calibration gas certificates of analysis. This central file also serves as an archive for all CEM records including log books, daily data summaries, maintenance request forms, and strip charts (as applicable).

The CEMS Data Acquisition and Reporting are controlled by a Data Acquisition and Handling System (DAHS). The DAHS provides automated data monitoring and management capabilities to the CEMS using KVB-Enertec NTDAHS software on a Windows platform.

The CEMS has a Programmable Logic Controller (PLC). The PLC transmits data from the analyzer to the DAHS. The DAHS polls the PLC every ten (10) seconds for data to generate and store one (1) minute averages. The DAHS will indicate any occurrence of specification limit exceedances or CEM operational problems. In the DAHS, necessary reports are generated in the required format for submittal to the applicable regulatory agencies.

Each electronic report submitted to the EPA will be in a single ASCII flat file. The file will be terminated with an ASCII end-of-file character. Each record will begin with the three digit "Record Type Code". All hourly data will be recorded in Standard Time, thus adjustments for daylight savings are not allowed. Each quarterly report will be submitted within 30 days of the end of each quarter. The EPA will acknowledge receipt of all reports received electronically.

All information reported to EPA Region 4 and the FDEP is maintained on file for a minimum of three years (§75.54).

### 1.8 Data Capture Requirements

The CEMS must be capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute interval (40 CFR 75, §75.10(iii)(d)(1)). Emissions concentrations collected by the monitors will be reduced to hourly averages. Hourly averages will consist of at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour.

An hourly average may be computed from two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) if data are unavailable due to performance of a calibration, quality assurance, or preventive maintenance activities. All valid measurements or data points collected during an hour will be used to calculate hourly averages. All data points collected during an hour will be, to the extent practicable, evenly spaced over the hour.

Failure to acquire the minimum number of data points for calculation of an hourly average will result in the failure to obtain a valid hour of data and the loss of such component data for the entire hour. An hourly average $NO_X$ emission rate in lb/mmBtu is valid only if both the pollutant and diluent monitors acquire the minimum number of data points.

If a valid hour if data is not obtained, the owner/operator will estimate and record emissions for the missing hour by means of the DAHS in accordance with the missing data substitution procedures outlined in 40 CFR 75, Subpart D.

## 1.9 Quality Assurance Status

A monitor is considered out-of-control starting with the hour of the failure of any quality assurance test. A test which is initiated and discontinued because the monitoring system is failing to meet the applicable performance specification or is otherwise found to be out-of-control is considered a failed test and the monitoring system is considered out-of-control starting with the hour in which the test was discontinued.

A system is also considered out-of-control beginning in the first hour following the expiration of a previous test if the owner/operator fails to perform a required periodic test.

A system is considered in-control in the hour in which all tests were failed or missed are successfully completed.

## 1.10 Reporting During Out-of-Control Hours

During the period that the CEMS is out-of-control, not operating, or otherwise determined, based on sound engineering judgement or for a known reason, to be producing inaccurate data, the owner/operator must do one of the following:

1. Measure and report data from a backup monitoring system that has met all of the initial and ongoing quality assurance requirements of 40 CFR 75, Appendix B.

2. Measure and report data using a reference method monitoring system.

3. Estimate and report data using the missing data procedures defined in 40 CFR 75, Appendix C.

**Table 1-1. Quality Assurance Test Requirements Summary**
(Reference 40 CFR 75, Appendix B, Figure 1 and Figure 2)

| QA TEST | DAILY* | QUARTERLY* | SEMIANNUAL* | ANNUAL* |
|---|---|---|---|---|
| Calibration Error (2 point) | ✓ | | | |
| Linearity (3 point) | | ✓ | | |
| RATA - gas analyzers | | | ✓ | ✓ [1] |

* – For monitors on bypass stack/duct, "daily" means bypass operating days, only. "Quarterly" means once every QA operating quarter. "Semiannual" means once every two QA operating quarters. "Annual" means once every four operating quarters.

[1] – Testing frequency in Table 1-1 may be reduced if the test results meet the requirements of the incentive program listed in Table 1-2.

**Table 1-2. Relative Accuracy Test Frequency Incentive Program**

| RATA | SEMIANNUAL[1] | ANNUAL[1] |
|---|---|---|
| $NO_x$/diluent | 7.5% < RA ≤ 10% or ±0.020 lb/mmBtu[2, 4] | RA ≤ 7.5% or ±0.015 lb/mmBtu[2, 4] |
| $O_2$ | 7.5% < RA ≤ 10% or ±1.0% $O_2$[2] | RA ≤ 7.5% or ±0.7% $O_2$[2] |

[1] – The deadline for the next RATA is the end of the second (if semiannual) or fourth (if annual) successive QA operating quarters following the quarter in which the CEMS was last tested. Exclude calendar quarters with fewer than 168 operating hours (or, for common stacks and bypass stacks, exclude quarters with fewer than 168 stack operating hours) in determining the RATA deadline. However, the exclusion of calendar quarters is limited as follows: the deadline for the next RATA shall be no more than 8 calendar quarters after the quarter in which a RATA was last performed.

[2] – The difference between monitor and reference method mean values apply to $O_2$ monitors or low emitters, only.

[4] – If average reading of $NO_X$ is ≤0.20 lb/mmBtu then use the ±0.02 lb/mmBtu semiannual and ±0.015 lb/mmBtu annual alternate criteria.

# 2.0 SUMMARY OF AFFECTED FACILITY AND CEM SYSTEM

## 2.1 Facility Description

The Jacksonville Electric Authority's (JEA) Brandy Branch Generating Station consists of three (3) dual-fueled nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators and three (3) 90-foot stacks. The units will operate in simple cycle mode and intermittent duty. The units will be equipped with Dry Low $NO_X$ combustors and wet injection capability.

The facility is located approximately 1 mile N.E. of Baldwin City, Duval County, Florida.

## 2.2 CEM System Description

The CEMS uses a straight extractive measurement technique that utilizes the stack as the process measurement interface. Each system automatically and continuously measures concentrations of oxygen ($O_2$) and oxides of nitrogen ($NO_x$).

Measurement outputs are low-level signals suitable for recording or operating the control system. The signals are transmitted to the Data Acquisition and Handling System (DAHS) via communication links. Contact closures are provided for alarms and system status.

Complete system operation, including calibration and sequencing is automatic. Operator attention is necessary only for periodic manual verification of accuracy and normal maintenance.

Historical data may be downloaded onto disk or tape for reporting, record keeping, or backup.

The CEMS is comprised of the following principal components:

1. Sample probe with filter. The probe enclosure is heated to prevent moisture condensation and contains valves to allow probe purge and probe calibration.

2. Heat-traced sample line from each sample probe terminates at its Main Analysis Enclosure. The heated sample line contains wiring and a bundle of tubes to transport sample and calibration gases between each sample probe enclosure and the Main Analysis Enclosure.

3. The Main Analysis Enclosure houses the sample conditioning system, a Programmable Logic Controller (PLC), and gas analyzers.

4. The Data Acquisition and Handling System (DAHS) consisting of an IBM-compatible computer with a hard drive, CRT, modem, printer, mouse and keyboard is usually located in the control room.

5. Calibration gas bottles that are mounted on the outside of the CEMS shelter.

### 2.2.1 Analyzers Included in the CEMS

**CTG1 CEMS**

| Analyzer | Manufacturer/Model | Analyzer Range |
|---|---|---|
| $NO_X$ | TECO Model 42CHL | 0-20/0-100 ppm |
| $O_2$ | Servomex Model 1440C | 0-25% |

**CTG2 CEMS**

| Analyzer | Manufacturer/Model | Analyzer Range |
|---|---|---|
| $NO_X$ | TECO Model 42CHL | 0-20/0-100 ppm |
| $O_2$ | Servomex Model 1440C | 0-25% |

**CTG3 CEMS**

| Analyzer | Manufacturer/Model | Analyzer Range |
|---|---|---|
| $NO_X$ | TECO Model 42CHL | 0-20/0-100 ppm |
| $O_2$ | Servomex Model 1440C | 0-25% |

## 2.3 Gas Sample System

### 2.3.1 Gas Extraction and Transport System

Particulate matter and moisture must be removed from the sample to present a clean, dry representative sample to the gas analyzers.

The following paragraphs describe the function and operation of system components arranged according to the normal flow of sample gas from the sample probe to the gas analyzers.

### 2.3.2 Sample Probe, Filter and Enclosure

The KVB probe is designed for continuous extraction of gases from dust laden, wet, and high temperature processes. The design features easy installation, reliable operation and trouble free maintenance. The probe is constructed of materials that resist corrosion for long operation life. The probe provides the first stage of sample conditioning with a 5 micron filter. Calibration gases are directly injected at the probe enclosure to assure accurate measurement results.

The probe enclosure is heated to keep the valves, filter, tubing and sample gas above the dew point to prevent condensation. The adjustable temperature switch used to control the heater is factory set to 250-300°F. During probe maintenance, verify the heater is operating correctly. A loss of heat could cause scrubbing of the sample gas.

An electrically actuated valve is used for probe calibration. During normal sampling the 3-way isolation valve is set to allow sample gas to flow from the sample probe and into the heated sample line that carries the sample gas to the analyzers.

During a calibration the cal gas bottle valves are opened to allow calibration gas to flow through the probe enclosure and sample line to the analyzers. The isolate valve is energized to prevent sample gas intermingling with calibration gas.

### 2.3.3 Heat-Traced Sample Line

The heat-traced sample line transports sample gas from each sample probe enclosure to a Main Analysis Enclosure. This line maintains the sample gas above the dewpoint, preventing the moisture in the sample from condensing and biasing the analyzer response low.

The line contains several tubes. Depending on your application, these lines may be made of Teflon, Stainless Steel, or Perm-Bar. Please note that Perm-Bar has a temperature limitation of 250°F, while Teflon has a temperature limitation of 425°F.

A 3/8" tube transports sample gas to the Main Analysis Enclosure. A 1/4" tube transports calibration gas for a probe calibration. Another 3/8" tube is a spare. The heat-traced sample line is insulated with inorganic fiber material and covered with a freeze-protected jacket.

### 2.3.4 Sample Conditioning

Removing the moisture from the sample is accomplished using a completely self-contained sample conditioning system. The primary components of the sample conditioning system are a sample cooler, a sample pump, a dual-head peristaltic pump for removing water from the sample cooler, and a safety water detection sensor.

### 2.3.5 Sample Gas Cooler

The Refrigeration Sample Cooler reduces the gas temperature to 35°F flowing at 15 liters per minute. Gas flows through a heat exchanger surrounded by a water and glycol medium that absorbs the heat. The gas velocity is reduced and is introduced into a separator in a spiraling fashion to spin the water out. The gas and condensed water flow to a water reservoir separator where the water is removed by the peristaltic pump. There are two passes in the refrigerated condenser. The first pass is on the vacuum side of the sample pump. The second pass is on the pressurized side of the sample pump.

### 2.3.6 Condenser Drain

Two peristaltic pumps continuously drain the condensation moisture traps. The pumps are activated by a fixed-speed drive, rotating at 6 RPM.

### 2.3.7 In-Line Filter

Sample gas flows through an in line filter, removing particulate which could damage downstream components. The filter is of the fine in-line type with a replaceable filter element, which can trap particles as small as 2.0 microns.

After flowing through the filter, the sample gas flows past the vacuum gauge. Maintenance intervals will depend upon quantity of particulate matter at the point of sample extraction.

### 2.3.8 Sample Pump

The sample pump is a positive-displacement type that utilizes a moving diaphragm. During normal operation, the pressure at the pump outlet is set at 10 psi, using the backpressure regulator.

When the enclosure is located a considerable distance from the sample point, restriction on the sample lines may induce a substantial vacuum at the pump inlet. Be alert for leaks that could affect accurate measurement, especially where a long sample line run causes a pump inlet vacuum greater than 10" Hg.

The pump shuts down automatically if the conductivity sensor detects moisture in the sample system tubing downstream of the sample gas cooler. The controller also shuts down the sample pump in the event of a fatal alarm if excess moisture is detected in the sample stream that can cause damage to the individual analyzers.

### 2.3.9 Moisture (Conductivity) Sensor

The conductivity sensor monitors the sample gas stream at the sample gas cooler outlet to detect any moisture, which could damage the gas analyzers. Any droplet of moisture across the conductivity sensor electrodes simulates a switch. The Moisture Sensor then sends a signal to the PLC controller causing an alarm. The moisture sensor is also connected to a relay board that automatically shuts off the sample pump, should moisture be detected downstream of the sample conditioner.

### 2.3.10 Total Flow Meter

A rotameter indicates the sample flow rate at the pump outlet. The flow rate should be approximately 5 to 7 liters per minute, depending on the sample line length and sample system vacuum.

### 2.3.11 Sample Flow Meter

Sample gas flow for each analyzer is indicated and controlled by a rotameter. The rotameter flow rate should be approximately 1 liter per minute.

### 2.3.12 Back Pressure Regulator

The sample gas flows through the total flow meter at a rate of approximately 7 liters. The gas flow then divides and flows through the sample flow meter. Excess sample gas is vented through a backpressure regulator.

## 2.4 Sample Analysis

### 2.4.1 TECO Model 42C $NO_x$ Analyzer

The TECO Model 42C, a chemiluminescent analyzer, is used to measure oxides of nitrogen. It is based on the principle that nitric oxide and ozone react to produce a characteristic luminescence with an intensity linearly proportional to the concentration of nitric oxide. Infrared light emission results when the electronically excited $NO_2$ molecules decay to lower energy states.

Nitrogen dioxide must first be transformed into nitric oxide before it can be measured using the chemiluminescent reaction. A molybdenum converter is heated to approximately 325°C to convert $NO_2$ to NO.

The gas sample enters the analyzer through the sample bulkhead. The sample flows through a particulate filter, a capillary, and then to the mode solenoid valve. The solenoid valve routes the sample either straight to the reaction chamber (NO mode) or through the $NO_2$-to-NO converter and then to the reaction chamber ($NO_x$ mode.).

Dry air enters the Model 42C through the dry air bulkhead, through a flow sensor and then through a silent discharge ozonator. The ozonator generates the necessary ozone concentration needed for the chemiluminescent reaction. The ozone reacts with the NO in the ambient air sample to produce electronically excited $NO_2$ molecules. A photomultiplier tube (PMT) housed in a thermoelectric cooler detects the $NO_2$ luminescence.

The NO and $NO_x$ concentrations calculated in the NO and $NO_2$ modes are stored in memory. The differences between the concentration are used to calculate the $NO_2$ concentration. The Model 42C outputs NO, $NO_2$ and $NO_x$ concentrations to both the front panel display and the analog outputs.

### 2.4.2 Servomex 1440C $O_2$ Analyzer

The Servomex Model 1440C oxygen analyzer measures the paramagnetic susceptibility of the sample gas by means of a magneto-dynamic measuring cell. Oxygen is virtually unique in being a paramagnetic gas, this means that it is attracted into a magnetic field.

In the Servomex measuring cell the oxygen concentration is detected by means of a dumb-bell mounted on a torque suspension in a strong, non-linear magnetic field. The higher the concentration of oxygen the greater this dumb-bell is deflected from its rest position. Around the dumb-bell is a coil of wire. A current is passed through this coil to return the dumb-bell to its original position. The current is measured and is proportional to the oxygen concentration.

## 2.5 Data Acquisition System

KVB-Enertec offers a multi-tasking, multi-user package that supports all 40CFR 60 and 75, state and local regulations. Developed specifically to operate on KVB-Enertec CEM systems, our microprocessor based DAHS converts regulatory data into an emissions and operations information management tool to enhance your daily site and corporate management operations. The KVB-Enertec NTDAHS software package provides a graphical user interface, seamless integration into your existing systems, and other advanced features to address both site and plant-wide communications needs.

The DAHS consists of software and two hardware components – a data acquisition computer (DAC), and a remote data collection node (RDCN). The part connected to the analyzers is the RDCN. A number of process-operating parameters are monitored by the RDCN and logged by the DAC. These include calibration control, alarms, analyzer status and process status.

The RDCN consists of the programmable logic controller (PLC) modules. Emissions data is collected from the analyzers via the PLC connected to a high-speed local area network using RS-422 protocol. A number of process-operating parameters are monitored by the RDCN and logged by the DAC. These include calibration control, alarms, analyzer status, and process status.

The DAC consists of an IBM compatible computer, associated hardware and the KVB-Enertec, Inc. NTDAHS software. The DAHS provides the functions required to fully meet 40 CFR Part 60. The system also provides a configurable environment to fulfill all state and local regulations as defined by the site's air permit. Reports may be produced in either hard copy or electronic format.

The operating system for the DAC is Microsoft Windows NT® 4.0. KVB-Enertec, Inc.'s DAC uses all the latest features of the Windows NT operating system to allow the user access to the data collected via a variety of networks and software packages. Open access and connectivity is the key design philosophy behind the many features available.

KVB-Enertec's NTDAHS software allows the operator to monitor the real time readings for all collected data channels as well as minute and hour averages and the status of the collected signal. Episodes for emission exceedances as well as alarm status can be viewed on the real time display.

NTDAHS is based on a graphical users interface that offers "Information-at-a-Glance" so that even the most inexperienced operator can understand the data necessary for efficient CEMS operation and maintenance. In addition it offers:

- Data Base - A powerful regional data base that stores real-time data for immediate and future access
- Graphics - Graphical displays of historical and present data for view on the screen or printing
- Reports - The system enables users to generate, view, print, delete, and copy to disk a variety of reports. Reports can be generated in ASCII formats for copy to disk (electronic format) and submittal to regulatory agencies.
- Remote Access – Whether using a network or modem, the NT technology allows your desktop screen to look identical to the DAHS screen.
- Data Display – An instantaneous data display is available for every data channel

# 3.0 SYSTEM STARTUP, CALIBRATION, AND ROUTINE OPERATION

## 3.1 General

This section contains start-up procedures for the CEMS following a shutdown period. It also contains procedures for a calibration (both automatic and manual modes) to be performed routinely or at operator discretion, to check and assure that the system is operating correctly and with consistent accuracy.

### 3.1.1 Safety Check

Safety awareness of the operational and/or maintenance aspects of any equipment unit should be inherent in the workplace. Before beginning or restarting operation of any CEM unit or system, a safety awareness approach calls for a visual check by an operator who is knowledgeable with the system. In general, the lead person responsible for the operation of the emissions monitoring equipment should perform the following checks.

The information presented below is not intended to be site specific or to contain all safety information that may be applicable to the facility. This section is intended to cover general aspects that the operating personnel should be aware of. All staff should be aware of the specific safety guidance and/or directives that their employer requires of them in the performance of their duties.

If the facility was shut down for maintenance purposes, check that all work orders for all disciplines (electrical, instrumentation and mechanical) have been completed, or that the work has been completed to a degree that the equipment is again operational. Specific maintenance procedures may apply to your facility, in which case it requires that staff be familiar with those procedures.

When electrical work has been performed, check that all panel covers have been replaced, and any breakers, which are required for operation of the components, are in the "on" position. Check that any jumpers have been removed, and that all components are operational. Check that all electrical connections have been made to plugs with the proper voltage, or to the same outlets which have been previously used unless otherwise directed by maintenance staff.

When instrumentation repairs have been completed, check that all instrument covers have been replaced and that any jumpers have been removed from the systems unless otherwise directed by maintenance personnel. Ensure that all units have been slid back into the rack.

After mechanical work has been completed, check that all major components are in place. Check the outside of the structure to ensure that all ladders or other work implements have been removed. Check that all hatches and/or access doors have been put back in place.

For operational purposes, certain checks and procedures may need to be performed on a routine basis. Check that any such procedure has been completed and that the system and component switches have been set to the start-up position. Check that all tools have been removed. Operator familiarity with the system will allow personnel to immediately determine if anything seems to be missing or does not belong.

Portions of the monitoring system are generally mounted on the stack at a considerable height off the ground. Personnel should be aware of safety procedures to be followed when working at heights greater than six feet and in limited access areas.

In general, follow the procedures that are established for your facility in starting or restarting the system. Safety awareness, combined with a site specific program and common sense will enable the operating personnel to safely operate the system equipment.

### 3.1.2 Component Check

The operational integrity of the system components is dependent upon the status indicators of the units being fully functional. Before beginning or restarting the system, check that all indicator light bulbs and displays are operational. Check all knobs, dials, rocker switches, etc. to ensure they are in good working order. Check flowmeters for cleanliness and visual clarity, and check tubing for any loose connections or deterioration. Check all printers and recorders to ensure a sufficient paper supply. Check the calibration gas cylinders to ensure that all connections have been made and are secure. Be sure that all cylinders are open to supply the required gas.

Personnel who will operate the CEM system should take time to become familiar with the system components. Operator familiarity is necessary to be able to troubleshoot and identify minor problems that can become major and cause the system to be inoperable.

### 3.1.3 Shelter Temperature Control

Operation of the system components, particularly the electrical and instrumentation units must be in a controlled environment to ensure accurate and reliable operation. Some of the shelters will be equipped with air conditioners and/or heaters to maintain an environment that will maintain the stability and temperature of the instruments. This will depend on the location of the facility and the area's climatic conditions. The operating temperature should be determined in advance for heating or air conditioning, and personnel should check the thermostats daily. Desired temperatures of 70°F to 75°F should be maintained even when the equipment is not in operation.

## 3.2 Power Verification

1. Verify that all analyzer power switches and all circuit breakers are turned OFF.

2. Verify correct voltage and amperage entering the power distribution panel by comparing with drawings and specifications for this unit.

3. Verify proper ground connection at the power distribution panels. Verify shelter ground. Verify plant instrument ground is connected to isolated ground bar.

4. Turn on circuit breakers in power distribution panels, one at a time, and verify correct voltage and device operation of each circuit breaker. Turn on all analyzer power switches to verify proper analyzer operation.

## 3.3 Start-Up Procedures

KVB-Enertec personnel or qualified station personnel to assure proper system operation initially start the system up following installation.

The following paragraphs pertain to the start-up of the monitoring system after a short or extended shutdown period.

1. Place system in Maintenance Mode.

2. Allow the sample gas cooler to operate for 30 minutes until proper cooling block temperature is achieved.

> **WARNING**
> Do not allow the sample pump to operate until the sample gas cooler temperature has stabilized.

3. Verify that all calibration gas bottles are open and have over 300 psig (inlet stage of regulator) cylinder pressure.

4. Verify that all calibration gas bottles are set to 20 psig outlet pressure.

5. Adjust each analyzer flow meter to provide the required labeled flowrate. ($NO_x$ = 1.5 liters per minute, $O_2$ = 0.4 – 0.5 LPM). $NO_x$ should have excess flow that is visible on the appropriate bypass flowmeter next to it.

6. After sample conditioner reaches normal operating temperature place system in normal operating mode.

### 3.4 Normal System Sampling Flow Verification

1. Place system in Maintenance Mode.

2. Verify pressure gauge reads 0.

3. Verify pressure switch is set to 60 psig.

4. Verify vacuum gauge reads less than 5 in. Hg.

5. Adjust the filter regulator until the pressure regulator gauge reads 80 psig. This sets the pressure for probe purging.

6. Place system in automatic operating mode.

7. Adjust the back pressure regulator to allow total flow of 5 LPM.

8. Adjust each analyzer rotameter to provide 1.2 liter per minute.

9. Verify total flow rotameter is less than 5 liters per minute.

10. Verify that vacuum gauge indicates less than 5" Hg.

11. Perform leak check of system. Manually flow $NO_x$ span gas ($O_2$ free, balance of Nitrogen). Verify $O_2$ analyzer is reading <0.1 % $O_2$. If in-leakage is found, check all Swagelok fittings with leak detection solution ("SNOOP" or similar).

System sampling has now been verified and the CEMS should operate automatically.

### 3.5 Calibration

Calibration is performed automatically by the PLC once every 24 hours. When the controller starts the automatic calibration sequence, automatic sampling sequence is suspended and reset. Data outputs from the PLC are held at the last valid reading until the calibration process is complete. Certified calibration gases are routed up through the sample line to the probe and back down the normal extraction gas sample path to the analyzers. Although each analyzer may be calibrated individually, the normal automatic calibration performed by the CEMS calibrates all analyzers simultaneously.

The gas analyzers automatic calibration, provided by the PLC's program, is divided into several sequential events. During calibration, the PLC energizes the solenoid valves to allow calibration gas to flow to the sample probe and on to the instruments. The time internals for purging and flowing of calibration gases can be altered to match the length of the sample line.

Calibration Gas 1 flows for a preset time interval. Then the PLC flows Calibration Gas 2 and so forth until all appropriate gas bottles have been selected. Upon completion of the calibration check the PLC resets the automatic calibration sequence and resumes normal automatic sampling.

A failed calibration is indicated when either excessive drift in any analyzer is detected, or if a blocked probe alarm occurs during calibration. The operator can use the DAHS to manually initiate a calibration cycle at any time. KVB-Enertec recommends running a calibration check after any maintenance has been performed.

### 3.6 Routine Operation

The KVB-Enertec CEMSCAN® is designed to operate automatically with little operator attention. However, to assure optimal performance, follow the maintenance schedule in Chapter 6 and the routine operation procedures described below.

Perform the following procedures at least once a week to ensure accurate and reliable measurement.

1. Check flow rate of rotameters.

   Verify midscale readings, adjust if necessary. Large variations from required settings indicate a need for maintenance.

2. Check sample pressure.

   Verify pressure gauge reads at least 5 psi. If necessary, adjust with back pressure regulator. Large variations from the required settings indicate a need for maintenance.

3. Check sample vacuum.

   The sample vacuum is not adjustable and is only an indication of the condition of upstream components. As the vacuum reads higher, that is an indication of probe or sample line restriction; it should be checked.

4. Verify sample conditioning unit is operating properly. Check temperature LED (if so equipped) or temperature alarm light.

### 3.7 Minimize Downtime During Routine Operation

The goal of this section is to minimize downtime and the impact on data availability during normal routine maintenance. Following the steps on routine preventative maintenance as well as any additional maintenance requirements on all equipment supplied with this system will greatly reduce emergency or breakdown repairs. All necessary spare parts, tool and equipment should be available to the persons responsible for upkeep of this system at all times. This is critical to plant owners and operators since data availability (according to current EPA regulations) of 95% or less results in missing data substitution, which could have a substantial negative effect on permit limits and emission credits.

Some maintenance can be performed while the CEMS is operating, without effecting data integrity or system availability. Much of the CEMS servicing requires placing the system in Maintenance Request to perform the work. If the system is equipped with a back-up CEMS then service, calibration and a complete check to ensure the function and accuracy of the back-up system should be performed before transferring the data recording task to the back-up system. Ensure that the back-up CEMS is accurately analyzing, recording and reporting data before beginning the maintenance or repairs on the primary unit. Another way to minimize downtime is to take advantage of planned or unplanned steam generator/turbine trips, outages or overhauls. Maintain the DAHS in operational status at all time.

Spending excessive amounts of time in Maintenance Mode will also effect hourly emission averages. This in turn effects data availability. To help prevent loss of data it is helpful to know what constitutes a valid hour of data. During normal sampling, a valid hour of data requires four valid 15-minute averages. A 15-minute average containing only one valid 10-second output from the PLC is considered to be valid. So, during normal sampling, in order for the entire hour to be considered valid it must contain four valid 15-minute averages, with each average built upon at least one valid 10-second PLC dump.

It is important to note that these statistics for data acquisition and what constitutes a valid average may be effected by changes in EPA rules or applicable state regulations. It is strongly recommended that current EPA and state guidelines for valid data should be adhered to and maintenance and repairs should be coordinated so as not to adversely effect valid data averages.

### 3.8 Minimizing Time in Maintenance Mode

Limiting time in Maintenance Mode to 30 minutes or less per maintenance operation will make the servicing "transparent" to the system. Note that most systems purge for 30 seconds upon exiting Maintenance Mode and then remain invalid for up to 10 minutes. This brings the total time in either maintenance or invalid to 40 minutes. Don't attempt to "squeeze" that extra minute of service time out of an hour if it can wait until the next hour. Two valid 15-minute averages are required during a "maintenance/calibration hour" and 10 out of the 15 available minutes for one valid 15-minute average may already be used up by the purge cycle. Keep careful track of the time spent in Maintenance Mode with a chronograph-type wristwatch or a stopwatch.

Frequency of maintenance depends on many variables such as geographic location (humidity), fuel type, stack temperature and moisture content, etc. Consequently, scheduled maintenance intervals will vary from the general guidelines given in the KVB-Enertec, Inc. Operation and Maintenance (O&M) manual and the individual equipment manuals, which constitute the appendices to the O&M manual.

The following items are examples of components that can be serviced without effecting CEMS operation (as applicable to individual applications):

1. Desiccant for $NO_x$ analyzer
2. $CO_2$ source lamp check
3. $SO_2$ source lamp check
4. Cooling air filters on analyzers
5. Air conditioning filters
6. Printer ink cartridges
7. Printer air filters
8. Computer air filters
9. CEMS cabinet blower filters
10. UPS battery test and maintenance
11. UPS air filter
12. Opacity blower air filters
13. Flow blower air filters
14. Instrument air compressor air intake filters
15. Refrigerated instrument air dryer - clean condenser coils

Example of items which require Maintenance Mode to service include:

1. Probe filters
2. Sample line flush
3. System filters such as pre- and post-filter, charcoal, and Purafil replacement, as applicable
4. Analyzer capillaries
5. Sample pump diaphragms and flappers – also $NO_x$ and $SO_2$ pumps, as applicable
6. $CO_2$ scrubber maintenance
8. Instrument air-compressor oil change
9. Filter/regulator filter replacement

# 4.0 QUALITY CONTROL ACTIVITIES

## 4.1 Introduction

All CEM equipment is fully checked out and calibrated at the KVB-Enertec, Inc. facility prior to shipping to the site. Once delivered to the site, the equipment will be installed following guidelines provided by KVB-Enertec, Inc. Initial start-up and calibration procedures are performed by KVB-Enertec, Inc. field representatives. The start-up technicians perform calibration checks in order to verify the accuracy of each analyzer. The Data Acquisition and Handling System (DAHS) and all auxiliary equipment (modem, printer, chart recorders, etc.) are also tested and verified for correct operation and valid data.

## 4.2 Calibration and Audit Gases

All gases used for daily calibrations and daily calibration error tests must be certified by the supplier using the procedure described in 40 CFR 75, Appendix H (Revised Traceability Protocol No. 1). These gases must be certified by the supplier to be within 2.0% of the concentration specified on the gas cylinder label (tag value) or zero air material for the zero level only. The maximum certification shelf life for single concentration calibration and audit gases is 24 to 36 months. For combined concentrations of gases (such as $NO_x$ and CO in the same bottle) the maximum certification shelf life is equal to that of its most briefly certifiable component. If a certified gas is to be used after the certification period has ended, it must be re-certified. A gas standard may be re-certified if the gas pressure remaining in the cylinder is greater than 3.4 megapascals (i.e., 500 psig). Facility personnel will maintain calibration gas bottle certificate records for a minimum of three years.

Calibration gases are used to verify the accuracy of the gas analyzers. Daily calibration gases are used to verify that the instruments are within the allowable error limits for a two-point (zero or low span and high span) on a daily basis. Linearity Error calibration gases are used to verify that the instruments are within the allowable limits for a three-point calibration (low-, mid- and high-span) on a quarterly basis.

The gas cylinders are 2000 psig and must be changed at 150 psig (EPA specifies 100 psig) to maintain correct gas concentrations. Cylinder regulators are set to between 15 and 20 psig. Calibration gases should be reordered when the bottle pressure drops to 1000 psig. Normal daily calibrations will consume about 100 psig per week. Under normal usage rates, calibration cylinders should last more than three months. If the turbo-cal option is installed and used, gas consumption will be higher. Any manual calibrations in addition to the required daily calibration will also increase gas consumption.

Check gas cylinder pressures on a daily basis. Make sure there is enough gas in each cylinder to complete the calibration. The instrument could fail the calibration if the gas runs out during the calibration cycle. Calibration gas can be lost if the cylinder pressure is set too high (lifting the seat on the normally closed solenoid valve that controls gas flow), through leaking fittings, and through a leaking solenoid valve. Brass pressure regulators should be used only on cylinders containing $CO_2$ or $N_2$. Stainless steel regulators must be used on cylinders containing $NO_X$ and $SO_2$.

The cylinders will contain a known concentration of a single gas such as $N_2$ (used for zero or low span calibration), or blended gases such as $CO_2$, $NO_X$, $SO_2$, and $N_2$ (used for high span calibration). Refer to the manufacturer's certification sheet provided with each cylinder for the gas concentration, cylinder certification number, and Protocol 1 statement. Even though the cylinders usually have a tag listing the gas concentrations, always use the values on the certification sheet for entry into the DAHS. Also, record cylinder changes, gas concentrations, expiration dates, and certification numbers in the CEM maintenance log. Keep a copy of the certification sheet as part of the site records.

Even EPA Protocol 1 gas cylinders have been known to be in error. If an analyzer shows excessive drift after changing a cylinder, check the analyzer with the cylinder that was replaced, or another cylinder that is known to be accurate. Also, make sure the new gas values were entered correctly in the DAHS. If a cylinder is suspect, return it to the supplier or have it re-certified at an independent testing lab.

### 4.2.1 Zero Air Material

Zero air material (used in daily calibrations) is defined as:

1. A calibration gas certified by the gas vendor not to contain concentrations of $SO_2$, $NO_X$, or total hydrocarbons (THCs) above 0.1 ppm, a CO concentration above 1 ppm, or a $CO_2$ concentration above 400 ppm.

2. Ambient air conditioned and purified by a CEMS for which the CEMS manufacturer or vendor certifies that the CEMS model produces conditioned gases that does not contain concentrations of $SO_2$, $NO_X$, or THCs above 0.1 ppm, a CO concentration above 1 ppm, or a $CO_2$ concentration above 400 ppm.

3. A multicomponent mixture certified by the supplier of the mixture that the concentration of the component being zeroed is less than or equal to the applicable specified in condition 1 above and that the mixture's other components do not interfere with the CEM readings.

## 4.3 Daily Calibration Error Tests for $NO_X$ and $O_2$ Monitors

A two-point calibration error test of the $NO_X$ and $O_2$ monitors is performed automatically once during each unit operating day. The EPA requires the daily calibration error tests to be performed while the unit is operating for purposes of quality-assuring the data and testing the CEMS. This is because the readings from the CEMS are affected by temperature and pressure conditions.

An off-line daily calibration error test can be performed and can be used to validate data for a monitoring system if the following conditions are meet.

1. An initial certification test of the monitoring system is completed and the results are reported in the quarterly report required under §75.64. The off-line calibration demonstration consists of an off-line calibration error test followed by an on-line calibration error test. Both the off-line test and on-line test must meet the calibration error performance specifications described in Section 4.3.4. After completion of the off-line portion of the calibration demonstration, the zero and upscale monitor responses may be adjusted, but only toward the "true" values of the calibration gases used to perform the test and only in accordance with the routine calibration adjustment procedures specified in the CEMS Operation and Maintenance Manual and it's appendices. After these adjustments, no other adjustments to the monitoring system are allowed until after completion of the on-line portion of this off-line calibration demonstration. Within 26 hours of the completion of the off-line portion of the demonstration, the monitoring system must successfully complete the first attempted on-line calibration error test.

2. For each monitoring system that has passed the off-line calibration demonstration, a successful on-line calibration error test of the monitoring system must be completed no later that 26 unit operating hours after each off-line calibration error test used for data validation.

Units using dual range or auto-ranging monitors and units that use the maximum expected concentration to determine calibration gas values, must perform the calibration error test on each scale of the monitor used since the previous calibration error test.

Example, if the pollutant concentration has not exceeded the low-scale value since the previous calibration error test, the calibration error test may be performed on the low-scale range only. However, if the concentration has exceeded the low-scale value for one hour or longer since the previous calibration error test, the calibration error test must be performed for both ranges of the affected monitors.

### 4.3.1 Conducting the Daily Calibration Error Test

The two-point calibration error test refers to two concentrations for which the calibration error must be calculated. These concentrations are (1) zero to 20 percent of span (zero-level) and (2) 80 to 100 percent of span (high-level). Calibration gas concentrations for daily calibration error tests are shown in Table 4-1. Alternately, a mid-level calibration gas (50 to 60% of span) may be used in lieu of the high-level gas if the mid-level gas is more representative of actual stack gas concentrations.

During calibration, the system controller energizes normally closed solenoid valves to allow the calibration gases to flow. The appropriate calibration gas is introduced into the probe. The monitors are challenged once with each level of the calibration gases. Each gas flows for approximately 10 minutes. The monitor response is recorded by the DAHS.

Do not make manual adjustments to the monitor settings until after taking measurements at both zero and high concentration levels for that day.

The DAHS compares the actual analyzer reading with the expected value of the calibration gas. If the analyzer drift exceeds the specification limits, the failure is indicated on the calibration report. When the daily calibration exceeds the specification limits, this indicates a need for corrective actions. Corrective actions may include, but are not limited to, manual calibration of the failed analyzer.

The calibration error for $NO_X$ pollutant concentration monitors is computed by the DAHS from the test results for each concentration level as follows (40 CFR 75, Appendix A Equation A-5):

$$CE = \frac{|R - A|}{S} x 100$$

Where:

| | | | |
|---|---|---|---|
| | CE | = | Calibration error as a percentage of span of instrument |
| | R | = | Zero or high level calibration gas value, ppm |
| | A | = | Actual monitor response to calibration gas, ppm |
| | S | = | Span of the instrument |

The calibration error for $O_2$ monitors is computed by the DAHS from the test results for each concentration level as follows (40 CFR 75, Appendix A, Equation A-5):

$$CE = |R - A|$$

Where:

| | | | |
|---|---|---|---|
| | CE | = | Calibration error as a percentage of $O_2$ |
| | R | = | Zero or high level calibration gas value, % |
| | A | = | Actual monitor response to calibration gas, % |

### 4.3.2 Additional Calibration Error Tests and Adjustments

Additional calibration error tests must be performed whenever a daily calibration error test has failed; whenever a monitoring system is returned to service after repair or corrective maintenance that could affect the monitor's ability to measure and record emissions data; or after making certain calibration adjustments. Except for routine calibration adjustments, data from the monitor are considered invalid until successful completion of a calibration error test.

Routine calibration adjustments are permitted after any successful calibration error test. These routine adjustments can be done to bring monitor readings as close as possible to the calibration gas reference values. An additional calibration error test is required following routine calibration adjustments when the monitor's calibration has been physically adjusted (i.e., by turning a potentiometer) to verify that the adjustments have been done correctly. An additional calibration error test is not required if the routine calibration adjustments are made by means of a mathematical algorithm programmed into the data acquisition system. The EPA recommends that calibration adjustments be made whenever the daily calibration error exceeds the applicable performance specifications.

Additional (non-routine) calibration adjustments of a monitor are permitted before (but not during) linearity checks and RATAs.

### 4.3.3 Recalibration Limits

The EPA recommends adjusting the calibration, at a minimum, whenever the daily calibration error exceeds the criteria specified in 40 CFR 75, Appendix A. The two-point calibration error test is then repeated after adjustments. The recommended recalibration criteria for the $NO_X$ concentration monitors is CE >2.5% (40 CFR 75, Appendix A, Section 3.1). For the $O_2$ monitor, the recommended recalibration criterion is $|R - A| > 0.5\%$ $O_2$ (40 CFR 75, Appendix A, Section 3.1).

### 4.3.4 Out-of-Control Limits

Out-of-control periods occur when the calibration error exceeds twice the recalibration criteria stated above (i.e. CE >5.0% or exceeds 10 ppm difference for span values of <200 ppm for $NO_X$, or CE >1.0% for $O_2$). The out-of-control criteria are also shown in Table 4-2. The out-of-control period begins with the hour of the failed calibration error test and ends with the hour of the next satisfactory calibration error test after corrective action. If the failed calibration error test, corrective action, and satisfactory calibration error test occur within the same hour, the hour is not considered out-of-control if two or more valid readings are obtained during the hour. A $NO_X$ monitoring system is considered out-of-control if either component (i.e. $NO_X$ or $O_2$ components) exceeds twice the application specification.

The DAHS records the calibration error test results and "flags" the calibration report if the recalibration (or out-of-control) criteria are exceeded. Recalibration or corrective action is taken when the failure is identified.

During the period the CEMS is out-of-control, the CEMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availability.

## 4.4 Fuel Flowmeter Measurements - (40 CFR 75, Appendix D, Section 2)

For each hour that the unit is combusting fuel, measure and record the flow of fuel combusted by the unit. Measure the flow of fuel with an in-line fuel flowmeter and automatically record the data by the DAHS.

Measure fuel flow for purposes of calculating heat input for the affected units as required for recordkeeping and compliance purposes. The information required for reporting includes apportionment using fuel flow measurements, the ratio of load (in MW) in each unit to the total load for all units receiving fuel from a common pipe header.

Each fuel flowmeter must meet a flowmeter accuracy of ±2.0% of the upper range value (i.e., maximum calibrated fuel flow rate), either by design or as calibrated and measured under conditions specified by the manufacturer, independent laboratory, or by the owner/operator. The flowmeter accuracy must include all error from all parts of the fuel flowmeter being calibration based on the contribution to the error in the flowrate.

## 4.5 Data Recording and Data Validation

Record and tabulate all calibration error test data according to month, day, clock-hour, and magnitude in ppm, percent volume, percent opacity, or scfh (as applicable to individual applications). For program monitors which automatically adjust data to the corrected calibration values record either the unadjusted concentrations measured in the calibration error test prior to resetting the calibration or the magnitude of any adjustment. (40 CFR 75, Appendix B, Section 2.1.6)

When a monitoring system passes a daily assessment (daily calibration error test), data from that monitoring system are considered valid for 26 clock hours (24 hours plus a 2-hour grace period) beginning with the hour in which the test is passed, unless another assessment is failed within the 26-hour period. These other assessments consist of additional calibration error checks, or a quarterly linearity check, or a relative accuracy test audit.

Data is considered invalid, beginning with the first hour following the expiration of a 26 hour data validation period or beginning with the first hour following the expiration of an 8-hour start-up period (refer to next section), if a subsequent passing daily assessment has not been conducted.

If an on-line daily calibration error test of the monitoring system in not conducted and passed within 26 unit operating hours of an off-line calibration error test that is used for data validation, then data from that monitoring system are invalid beginning with the 27$^{th}$ unit operating hour following that off-line calibration error test.

Keep a written record of the specific fuel flowmeter, transducer and/or transmitter accuracy test procedures. Keep a written record of adjustments, maintenance, or repairs performed on the fuel flowmeter monitoring system.

Keep records of the standard operating procedures for inspection of the primary element of an orifice-, venturi-, or nozzle-type fuel flowmeter. These should include what to examine on the primary element; how to identify corrosion that may affect the accuracy of the primary element; and what tools (e.g., baroscope), if any, are used.

Keep a written record of the standard procedures used to perform fuel sampling, either by utility personnel or by fuel supply company personnel. These procedures should specify the portion of the ASTM method used, as reference under § 75.6 or other methods as approved by the local Administrator. These procedures should describe safeguards for ensuring the availability of an oil sample. These procedures should identify the ASTM analytical methods used to analyze sulfur content, gross calorific value, and density.

## 4.6 Daily Assessment Start-Up Grace Period

A start-up grace period may apply when a unit begins to operate after a period of non-operation. The requirements to qualify for a start-up grace period is as follows:

1. The unit must have resumed operation after being in outage for 1 or more hours (i.e., the unit must be in a start-up condition) as evidenced by a change in operating time from zero in one clock hour to an operating time greater than zero in the next clock time.

2. For a monitoring system to be used to validate data during the grace period, the previous daily assessment must have passed on-line within 26 clock hours prior to the last hour in which the unit operated before the outage. The monitoring system must also be in-control with respect to quarterly and semi-annual or annual assessments.

If these conditions are met, then a start-up grace period of up to 8 clock hours applies, beginning with the first hour of unit operation following the outage. During the start-up grace period, data generated by the monitoring system are considered quality-assured. A start-up grace period for a calibration error test ends when:

1. A daily assessment (calibration error test) is performed; or

2. 8 clock hours have elapsed (starting with the first hour of unit operation following the outage), whichever occurs first.

Table 4-1. Typical Daily Calibration Gas Concentrations

| $O_2$ Analyzer: Measurement Range = 0-25% | Gas Concentration |
|---|---|
| Zero (0 to 20% of span) | 0 – 5% |
| High (80 to 100% of span) | 20 – 25% |

| $NO_x$ Analyzer: Measurement Range = 20 ppm | Gas Concentration |
|---|---|
| Zero (0 to 20% of span) | 0 - 4 ppm |
| High (80 to 100% of span) | 16 - 20 ppm |

| $NO_x$ Analyzer: Measurement Range = 100 ppm | Gas Concentration |
|---|---|
| Zero (0 to 20% of span) | 0 - 20 ppm |
| High (80 to 100% of span) | 80 - 100 ppm |

NOTE: Do not use gas cylinders if the pressure has fallen below 150 psig.

Table 4-2. Criteria for Excessive Calibration Drift

| Analyzer | Recommended Recalibration Criteria | Out-of-Control Criteria |
|---|---|---|
| $NO_x$ | 2.5% of span* | 5.0% of span* |
| $O_2$ | 0.5% $O_2$ | 1.0% $O_2$ |

* $NO_X$ with ranges of <200 ppm can use alternate criteria.
Recommended recalibration criteria = 5 ppm difference and Out-of-Control Criteria = 10 ppm difference.

Table 4-3. Example of Calibration Gas Cylinder Log Form

| Date Installed | Cylinder Serial Number | Expiration Date | Concentration |
|---|---|---|---|
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# 5.0 QUALITY ASSURANCE ACTIVITIES

## 5.1 Quarterly Assessments - (40 CFR 75, Appendix B, Section 2.2)

The following assessments will be performed during each calendar quarter that the unit combusts fuel. This requirement is in effect the calendar quarter following the calendar quarter in which the monitor or CEMS is certified.

## 5.2 Linearity Check - (40 CFR 75, Appendix B, Section 2.2.1)

The linearity check is performed for each $NO_X$ and $O_2$ monitor at least once during each unit operating quarter. Conduct the linearity checks no less than 30 days apart, to the extent practicable. For dual range analyzers, a linearity check is required only on the range(s) used to record and report emission data during the QA operating quarter. Use separate calibration gas cylinders for each concentration during the audit. When conducting the linearity test, the unit must be on-line. Operate the monitor(s) at its normal operating temperature and conditions.

*Note: If the $NO_X$ analyzer span value is ≤30 ppm, that range of the analyzer is exempt from the linearity test requirements. However, in lieu of a linearity error test, the state regulatory agency may require a two-point 40 CFR 60, Appendix F CGA test in place of the 40 CFR 75 linearity test. Check with the local regulatory agency on this matter.*

To conduct a Linearity Error Check:

1. Challenge the CEMS (both pollutant and diluent portions of the CEMS, if applicable), with an audit gas of known concentration at three points within the following concentration ranges (see Table 5.1 for gas concentrations):

| Audit Point | Pollutant and Diluent Monitors |
|---|---|
| Low | 20 to 30% of span value |
| Mid | 50 to 60% of span value |
| High | 80 to 100% of span value |

   Challenge the CEMS three times at each audit point. Do not use an individual gas concentration consecutively. Instead, alternate between low, mid and high values. Use the average of the three responses for each audit point in determining accuracy (see Table 5-2). The DAHS may be capable of performing this calculation. The monitor should be challenged at each audit point for a sufficient period of time to assure that any sample gas in the lines is flushed out and the calibration gas flow has stabilized. The injection time should also take into account the response time of the analyzers and sample system.

2. Operate each monitor in its normal sampling mode, i.e. pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. At a minimum, the audit gas should be introduced at the connection between the probe and sample line.

3. Use EPA Protocol 1 or NIST certified gases. The gases must be vendor-certified to be within 2.0% of the concentration specified on the cylinder label (tag value).

4. The difference between the actual concentration of the audit gas and the concentration indicated by the monitor will determine the accuracy of the CEMS.

Calculate the linearity error using the following equation (40 CFR 75, Appendix A, Section 7.1, Equation A-4):

$$LE = \frac{|R-A|}{R} \times 100$$

Where: LE = %, linearity error
R = calibration gas reference values
A = average of monitor responses

Linearity checks are acceptable for monitor certification if none of the test results exceed the applicable performance specifications of 40 CFR 75, Appendix A, Section 3.2. The results of the $NO_X$ and $O_2$ linearity check shall be less than 5.0% as calculated by the above equation or the alternative criteria of 0.5% $O_2$ or 5 ppm difference for $NO_X$ (Reference Method - 40 CFR 75, Appendix A, Section 3.2).

$$LE = |R - A|$$

Where: LE = %, linearity error
R = calibration gas reference values
A = average of monitor responses

### 5.2.1 Data Validation – Linearity Check (40 CFR 75, Appendix B, Section 2.2.3)

A linearity check cannot be performed if the monitoring system is operating out-of-control with respect to any required daily or semiannual quality assurance assessments.

The linearity check may be done after performing only routine or non-routine calibration adjustments at the various calibration gas levels (zero, mid, or high), but no other corrective maintenance, repair, re-linearization or reprogramming of the monitor is allowed. Trial gas injection runs may be performed after the calibration adjustments prior to the linearity check to optimize the performance of the monitor. The trial gas injections do not have to be reported provided they meet the specification for trial gas injections described in §75.20(b)(3)(vii)(E)(1). However, if this specification is not met, the trial injection will be counted as an aborted linearity check.

The linearity check may be done after repair, corrective maintenance or reprogramming of the monitor. In this case, the monitor will be considered out-of-control from the hour of the repair, corrective maintenance, or reprogramming was performed until the hour of a successful linearity check. Alternately, the data validation procedures and associated timelines in §§75.20(b)(3)(ii) through (ix) may be followed when the repair, corrective maintenance, or reprogramming of the monitor has been completed.

Once the linearity check has been started, no adjustments of the monitor are permitted during the test period other than routine calibration adjustments.

If a daily calibration error test failed during a linearity test period, prior to completing the test, the linearity check must be re-started. Data from the monitor are invalidated from the hour of the failed calibration error test until the hour of a successful calibration error test. The linearity error check cannot be re-started until a successful calibration error test has been completed.

For each monitoring system, report results of all completed and partial linearity tests that affect data validation in the required quarterly report. Linearity attempts that were aborted because of problems with the calibration gases or plant operational problems do not need to be reported. A record of all linearity tests, trail gas injections and test attempts (reported or unreported) must be kept on-site as part of the official test log for each monitoring system.

No more than four successive calendar quarters shall elapse after the quarter in which a linearity check was last performed without a subsequent linearity test having been conducted. If a linearity test has not been completed by the end of the fourth calendar quarter since the last linearity test, then the linearity test must be completed within a 168 unit operating hour grace period following the end of the fourth successive elapsed calendar quarter. Data collected by the monitoring system will otherwise be considered invalid.

**5.2.2 Linearity Error Grace Period** - (40 CFR 75, Appendix B, Section 2.2.4)

When a required linearity test has not been completed by the end of the QA operating calendar quarter in which it is due, or because of infrequent operation of a unit, infrequent use of a required high range monitor or monitoring system, four successive calendar quarters have elapsed after the quarter in which a linearity was last performed, the owner/operator has a grace period of 168 consecutive operating hours in which to perform the linearity test. The grace period starts with the operating hour following the calendar quarter in which the linearity test was due. Data validation during a linearity test grace period will be done in accordance with the applicable provisions outlined in 40 CFR 75, Appendix B, Section 2.2.3.

If at the end of this 168 unit operating hour grace period, the required tests have not been performed, data from the monitoring system will be considered invalid beginning with the hour of the missed 168 hour grace period. Data from the monitoring system will remain invalid until the hour of completion of a subsequent successful hands-off linearity test. A linearity test performed within a grace period satisfies the QA requirements for the missed quarter but not for the quarter that the grace period linearity test was completed.

**5.2.3 Out-of-Control Period** - (40 CFR 75, Appendix B, Section 2.2.3)

An out-of-control period occurs when the error in linearity at any of the three concentrations (six for dual range) exceeds the applicable specifications of >5% error (refer to 40 CFR 75, Appendix A, Section 3.2). The out-of-control period begins with the hour of the failed linearity check and ends with the hour of a satisfactory linearity check following the corrective action. For the $NO_x$ CEMS, the system is considered out-of-control if either of the component monitors ($NO_x$ or $O_2$) exceed the applicable specifications.

During the period the CEMS is out-of-control, the CEMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availability.

**5.3 Semiannual and Annual Assessments** - (40 CFR 75, Appendix B, Section 2.3)

Perform the following assessments (refer to 40 CFR 75, Appendix B, Section 2.3) either once every two successive operating quarters (semiannual) or once every four successive operating quarters (annual) after the calendar quarter in which the monitor was last tested, and no less than 4 months apart. These tests are conducted in accordance with the procedures contained in 40 CFR 75, Appendix A, Section 6.5. Please note that the EPA Regional office requires a 30-day notification of the RATA test schedule.

Exclude calendar quarters with fewer than 168 operating hours in determining the RATA deadline. However, the exclusion of calendar quarters is limited as follows: the deadline for the next RATA shall be no more than 8 calendar quarters after the quarter in which a RATA was last performed.

Relative accuracy test audits (RATAs) may be performed on an annual basis rather than a semi-annual basis under the following conditions, which are referred to as the "relative accuracy test frequency incentive program criteria:"

1. The relative accuracy during the previous audit for an $O_2$ monitor or $NO_X$ CEMS, is 7.5% or less.

An additional pass/fail criteria summary can be found in Table 1-4 in Section 1. As many RATA attempts as are necessary may be performed to achieve the desired RATA test frequencies and/or bias adjustment factors as long as the data validation procedures as described later in this chapter and in 40 CFR 75, Appendix A and B are followed.

The Relative Accuracy Test Audit (RATA) will be performed on-site for each $O_2$ and $NO_x$ monitoring system in accordance with 40 CFR 75, Appendix A, Section 6.5. An independent testing contractor will conduct these RATAs, in accordance with 40 CFR 75, Appendix A, Section 6.5.10. The selected Reference Test Methods for these RATAs are instrumental analyzer methods from 40 CFR 60, Appendix A. These Test Methods will be conducted in accordance with the corresponding Performance Specifications of 40 CFR 60, Appendix B as follows:

| Parameter | 40 CFR 60, Appendix A Test Method | 40 CFR 60, Appendix B Performance Specification |
|---|---|---|
| Traverse Points | 1 | N/A |
| $O_2$ | 3A | 3 |
| $NO_x$ | 7E | 2 |

Calibration gases will be selected in accordance with 40 CFR 60, Appendix A, Method 6C, Sections 5.3.1 through 5.3.3. Also, prior to conducting each RATA, the response time of the test CEMS and that of the utility CEMS will be determined. Based on these response times, the timing of the data will be adjusted to ensure proper correlation between the test CEMS results and that of the utility CEMS.

The Relative Accuracy Test Audits for the pollutant and diluent gas analyzers will be conducted simultaneously for each unit (i.e., simultaneous testing of each unit's $NO_x$, and $O_2$ monitors). During Relative Accuracy Testing, each unit will operate at its normal level and combusting its primary fuel (40 CFR 75, Appendix A, Sections 6.5.2 and 6.5, respectively).

For dual range analyzers, the RATA will be performed on the range that is normally used for measuring emissions. For units that use fuel switching or for which the emission controls are operated seasonally, either range may be considered normal. In such cases, the RATA will be performed on the range that is in use at the time of the scheduled test.

Reference Method measurement locations will be in accordance with 40 CFR 75, Appendix A, Section 6.5.5. Selection of the traverse point locations will comply with 40 CFR 75, Appendix A, Section 6.5.6. The traverse sampling points will be located so as to establish a "measurement line" through the centroidal area of the stack.

### 5.3.1 Load Level Definition

The owner/operator will determine the upper and lower boundaries of the range of operation for each unit. The lower boundary of the range of operation will be the minimum safe, stable load. The upper boundary of the range of operation will be the maximum sustainable load. The maximum sustainable load is the higher of either the nameplate or rated capacity of the unit, less any physical or regulatory limitations or other deratings; or the highest sustainable unit load, based on at least four quarters of representative historical operating data.

The operating levels for relative accuracy test audits will be (except for peaking units) as follows:

| | | |
|---|---|---|
| Low | - | The first 30% of the range of operation |
| Mid | - | The middle portion of the range of operation (>30% to 60%) |
| High | - | The upper end of the range of operation (>60% to 100%) |

The owner/operator will identify the "normal" load level or levels (low, mid or high) based on the operating history of the unit(s). To identify the normal load levels, at a minimum, determine the relative number of operating hours at each of the three load levels over the past four representative operating quarters. Determine to the nearest 0.1%, the percentage of the time that each load level has been used during that time period. A summary of the data used for this determination and calculated results must be kept on-site in a format suitable for inspection.

A second most frequently used load level may also be designated as an additional normal level.

For peaking units, normal load designations are unnecessary as the entire operating load range will be considered normal.

The owner/operator shall report the upper and lower boundaries of the range of operation for each unit, in units of megawatts or thousands of lb/hr of steam production, in the electronic quarterly report. Except for peaking units, in the electronic quarterly report the load level(s) designated as normal will also indicate the two most frequently used load levels.

### 5.3.2 Sampling Strategies

Reference Method measurement locations will be in accordance with 40 CFR 75, Appendix A, Section 6.5.5. Selection of the traverse point locations will comply with 40 CFR 75, Appendix A, Section 6.5.6. The traverse sampling points will be located so as to establish a "measurement line" through the centroidal area of the stack.

For moisture determinations where the moisture data are used only to determine stack gas molecular weight, a single reference method point, located at least 1.0 meter from the stack wall, will be used.

The minimum acceptable time for a gas monitoring system RATA run is 21 minutes. For each run of a gas monitoring system RATA, all necessary pollutant and diluent concentration measurements must, to the extent practicable, be made within a 60-minute period.

To properly correlate individual $NO_X$ emission data with the reference method data, the beginning and end of each reference method test run (including exact time of day) will be annotated on the chart recorder or other permanent recording device.

### 5.3.3 Correlation of Data

It will be confirmed that the monitoring system and reference method test results are on a consistent moisture, pressure, temperature, and diluent concentration basis (e.g., flow monitor measures flow rate on a wet basis, Method 2 test results must also be on a wet basis). Response times of the emission monitoring system and flow monitoring system will be compared with the reference method measurements to ensure comparison of simultaneous measurements.

For each RATA test run, the measurements from the monitors will be compared against the corresponding reference method values. The paired data will be tabulated in a table and relative accuracy results calculated.

A minimum of nine sets of paired monitor data and reference method test data will be performed.

More than nine sets of paired data may be collected. If done, a maximum of three sets of test results may be rejected, as long as the total number of test results is greater than or equal to nine.

All data, including any rejected paired runs will be reported.

### 5.3.4 Data Validation - (40 CFR 75, Appendix B, Section 2.3.2)

A RATA cannot be performed if the monitoring system is operating out-of-control with respect to any of the required daily and quarterly quality assurance assessments.

The RATA may be done with no corrective maintenance, repair, calibration adjustments, re-linearization or reprogramming of the monitoring system prior to the test.

The RATA may be done after performing only routine or non-routine calibration adjustments at the zero and/or upscale calibration gas levels, but no other corrective maintenance, repair, re-linearization or reprogramming of the monitoring system is allowed. Trial RATA runs may be performed after the calibration adjustments and additional adjustments within the allowable limits found in 40 CFR 75, Appendix B, Section 2.1.3 may be made prior to the RATA to optimize the performance of the CEMS. The trial RATA runs need not be reported provided they meet the specification for trial RATA runs in §75.20(b)(3)(vii)(E)(2). However, if this specification is not met, the trial run will be counted as an aborted RATA attempt.

The RATA may be done after repair, corrective maintenance, re-linearization or reprogramming of the monitoring system. In this case, the monitoring system will be considered out-of-control from the hour in which the repair, corrective maintenance, re-linearization or reprogramming is commenced until the RATA has passed. Alternately, the data validation and associated timelines in §§75.20(b)(3)(ii) through (ix) may be followed when repair, corrective maintenance, re-linearization or reprogramming has been completed.

Once a RATA has started, no adjustments of the monitor's calibration is permitted during the test period, other than routine adjustments following daily calibration error tests.

If a daily calibration error test failed during a RATA test period, prior to completing the test, the RATA must be repeated. Data from the monitor are invalidated from the hour of the failed calibration error test until the hour of completion of a subsequent successful calibration error test. The RATA cannot be re-started until the monitor has successfully passed a calibration error test.

If a RATA has failed or has been aborted prior to completion due to a problem with the CEMS, then the CEMS is out-of-control and all emission data from the CEMS are invalidated from the hour of the failed or aborted RATA until the hour of completion of a subsequent successful RATA. A monitoring system will not be considered out-of-control when a RATA is aborted for reasons other than monitoring system malfunction.

If the diluent monitor used as a component in a $NO_X$-diluent monitoring system fails, then both components of the system are considered out-of-control from the hour of completion of the failed diluent monitor RATA until the hour of completion of a subsequent hands-off RATA which demonstrates that both system components have passed the applicable specifications.

For each monitoring system, report the results of all completed and partial RATAs that affect data validation in the required quarterly report. RATA attempts that are aborted or invalidated due to problems with the reference method or due to operational problems with the affected unit(s) need not be reported. Such runs do not affect the validation status of emission data recorded by the CEMS. However, a record of all RATAs, trial RATA runs and RATA attempts must be kept on-site as part of the official test log for each monitoring system.

Failure of the bias test does not result in the system or monitor being out-of-control.

During the period the CEMS is out-of-control, the CEMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availability.

### 5.3.5 Emission Limits

The following emission limits are referenced from the facility's air permit. If needed for state required reporting, these emission limits will be utilized as the "applicable standard" for alternate pass/fail criteria for reporting 40 CFR 60 RATA results.

| | $NO_X$ |
|---|---|
| Natural Gas fired | 10.5 ppm @15%$O_2$ |
| No. 2 Fuel Oil | 42 ppm @ 15%$O_2$ |

### 5.3.6 $O_2$ Relative Accuracy Test

Relative accuracy of the $O_2$ monitor (diluent gas) will be conducted concurrently with the pollutant gas tests. EPA Test Method 3A, an instrumental test method, will be used proposed as the reference method for this QA/QC program. A sample is continuously extracted from the effluent stack gas stream. A portion of the sample stream is conveyed to a paramagnetic or polargraphic analyzer for the determination of $O_2$ concentration. The $O_2$ RATA will be conducted simultaneously with the $NO_x$ RATA. Each sample run will be 30 minutes in duration with approximately 15 minutes between sampling runs for test CEMS calibration.

For each Reference Method 3A determination, the flue gas will be sampled at a number of traverse points, which will be determined prior to testing using EPA Method 1 procedures. The differences between the reference method sample and the $O_2$ monitor's readings will be evaluated from a minimum of nine (9) sets of paired monitor and reference method test data (40 CFR 75, Appendix A, Section 6.5.9). From these differences, the 95% confidence coefficient is calculated, and the relative accuracy determined (40 CFR 75, Appendix A, Section 7.3). Any tests not included in the calculations for the determination of relative accuracy (maximum of three) will be included in the final test report.

The $O_2$ relative accuracy will be established on-site. In accordance with 40 CFR 75, Appendix A, Section 3.3.3, the $O_2$ RATA results are acceptable if the $O_2$ relative accuracy does not exceed 10.0% (semiannual). Alternately, if the mean difference of the $O_2$ monitor measurements and the corresponding reference method measurements, calculated using Equation A-7 of 40 CFR 75, Appendix A, are within ±1.0 percent $O_2$. Under the incentive program if the RATA results are ≤7.5% then the next RATA can be performed on an annual basis rather than semiannual. Alternately, the mean difference must not exceed ±0.7%.

If required for State regulatory reporting purposes additional relative accuracy calculations will be made in accordance with 40 CFR 60, Appendix B, Specification 3A. The $O_2$ relative accuracy test results are acceptable if the $O_2$ relative accuracy does not exceed 20.0% of the mean value of the RM test data in terms of units of the emission standard or 1.0% $O_2$. RATA is performed annually under 40 CFR 60.

### 5.3.7 $NO_x$ Relative Accuracy Test

EPA Test Method 7E, an instrumental test method, will be used proposed as the reference method for this QA/QC program. This method is an instrumental analyzer procedure. A sample is continuously extracted from the effluent gas stream. A portion of the sample stream is conveyed to an instrumental chemiluminescent analyzer for the determination of $NO_x$ concentration. The $NO_x$ RATA will be conducted simultaneously with the $O_2$ RATA. Each sample run will be 30 minutes in duration with approximately 15 minutes between sampling runs for test CEMS calibration.

For each reference method 7E determination, the flue gas will be sampled at a number of traverse points, which will be determined prior to testing using EPA Method 1 procedures. The difference between the reference method sample and the $NO_X$ monitor's reading will be evaluated from a minimum of nine sets of paired monitor and reference method test data (40 CFR 75, Appendix A, Section 6.5.9). From these differences, the 95% confidence coefficient is calculated, and the relative accuracy determined (40 CFR 75, Appendix A, Section 7.3). The diluent gas tests will be conducted concurrently with the pollutant gas tests. Any tests not included in the calculations for the determination of relative accuracy (maximum of three) will be included in the final test report.

The $NO_x$ relative accuracy will be established on-site. In accordance with 40 CFR 75, Appendix A, Section 3.3.2, the $NO_x$ RATA results are acceptable if the $NO_x$ relative accuracy does not exceed 10.0% (semiannual). Alternatively, if during the RATA the average $NO_x$ emission rate is less than or equal to 0.20 lb/MMBtu, the mean value of the $NO_x$ CEMS does not exceed ±0.02 lb/MMBtu of the reference method mean value. The alternative criteria will only be utilized if the 10% relative accuracy requirement is not achieved. Under the incentive program if the RATA results are ≤ 7.5% then the next RATA can be performed on an annual basis rather than semiannual. Alternately, if the average $NO_x$ emission rate is less than or equal to 0.20 lb/MMBtu, the mean difference must not exceed ±0.015 lb/MMBtu.

If required for State reporting purposes additional relative accuracy calculations will be made in accordance with 40 CFR 60, Appendix B, Specification 2. The $NO_X$ relative accuracy test results are acceptable if the $NO_X$ relative accuracy does not exceed 20.0% of the mean value of the RM test data in terms of units of the emission standard or 10% of the applicable standard, whichever is greater. RATA is performed annually under 40 CFR 60.

### 5.3.8 Relative Accuracy Calculations

The following equations will be used to calculate relative accuracy:

**Arithmetic Mean** - (40 CFR 75, Appendix A, Section 7.3.1, Equation A-7):

$$\bar{d} = \frac{1}{n}\sum_{i=1}^{n} d_i$$

Where: $n$ = number of data points

$\sum_{i=1}^{n} d_i$ = algebraic sum of the individual differences, di

**Standard Deviation** - (40 CFR 75, Appendix A, Section 7.3.2, Equation A-8):

$$S_d = \sqrt{\frac{\sum_{i=1}^{n} d_i^2 - \frac{\left(\sum_{i=1}^{n} d_i\right)^2}{n^2}}{n-1}}$$

**Confidence Coefficient** - (40 CFR 75, Appendix A, Section 7.3.3, Equation A-9):

$$cc = t_{0.025}\frac{S_d}{\sqrt{n}}$$

Where: $t_{0.025}$ = t value

**Relative Accuracy** - (40 CFR 75, Appendix A, Section 7.3.4, Equation A-10):

$$RA = \frac{|\bar{d}| + |cc|}{\overline{RM}} \times 100$$

Where:
- $\overline{RM}$ = arithmetic mean of the reference method values
- $\bar{d}$ = the absolute value of the mean difference between the reference method values and the corresponding CEMS values
- cc = absolute value of the confidence coefficient

### 5.3.9 Bias Test (Refer to 40 CFR 75, Appendix A, Section 7.6.4)

The bias test is conducted using the RATA data and the relative accuracy calculations. For $NO_X$, if the mean difference is positive and greater than the absolute value of the confidence coefficient, the $NO_X$ monitoring system has failed to meet the EPA's bias test criteria.

If the monitor fails to meet the bias test requirement, adjust the value obtained from the monitor using the equations in 40 CFR 75 Appendix A, 7.6.5.

$$CEM_i^{ADJUSTED} = CEM_i^{MONITOR} \times BAF$$

*Reference Method* - Equation A-11, 40 CFR 75, Appendix A,

Where:

$CEM^{ADJUSTED}$ = Data Value, adjusted for bias, at time i.

$CEM^{MONITOR}$ = Data (measurements) provided by the monitor at time i.

BAF = Bias Adjustment Factor, defined by

$$BAF = 1 + \frac{|\bar{d}|}{\overline{CEM}_{AVG}}$$

Where:

$|\bar{d}|$ = Arithmetic mean of the difference obtained during the failed bias test from the Arithmetic mean calculation of the relative accuracy test Audit

$\overline{CEM}_{AVG}$ = Mean of the data values provided by the monitor during the failed bias test

Apply this adjustment prospectively to all monitor data from the date and time of the failed bias test until the data and time of a relative accuracy test audit that does not show bias. Use the adjusted values in computing substitution values in the missing data procedures, and in reporting the emitted tons of $CO_2$ and the average $NO_x$ emission rate during the quarter and calendar year.

### 5.3.10 Out-of-Control Period - (40 CFR 75, Appendix B, Section 2.3.2)

An out-of-control period occurs when any of the following conditions exist:

1. When the relative accuracy of the $NO_x/O_2$ CEMS exceeds 10%.

For $NO_X$ and $O_2$ relative accuracy test audit at a single operating level, the out-of-control period begins with the hour of completion of the failed RATA and is over at the end of the hour of a passing RATA.

Failure of the bias test does not result in the system or monitor being out-of-control.

During the period the CEMS is out-of-control, the CEMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availability.

### 5.3.11 RATA Grace Period

The owner/operator has a grace period of 720 unit operating hours in which to complete the required RATA when the RATA has not been performed by the end of the QA operating quarter in which it is due; or eight (8) successive calendar quarters have elapsed, following the quarter in which a RATA was last performed, due to infrequent operation of the unit(s).

The grace period begins with the first unit operating hour following the calendar quarter in which the required RATA was due. Data validation during a RATA grace period shall be done in accordance with the application provisions found in 40 CFR 75, Appendix B, Section 2.3.2.

## 5.4 Fuel Flowmeters – (40 CFR 75, Appendix D, Section 2.1.6)

Recalibrate each fuel flowmeter to a flowmeter accuracy of ±2.0% of the upper range value at least once every four fuel flowmeter QA operating quarters. No more than 20 successive calendar quarters will elapse after the quarter in which a fuel flowmeter was last tested for accuracy without a subsequent flowmeter accuracy test heaving been conducted. Test more frequently if required by manufacturer specifications.

Except for orifice-, nozzle-, and venturi-type flowmeters, perform the recalibration using procedures outlined in 40 CFR 75, Appendix D, Section 2.1.5.1 or 2.1.5.2 ("Initial Certification Requirement for all Fuel Flowmeters"). Each fuel flowmeter must meet the 2.0% accuracy specification of 40 CFR 75, Appendix D, Section 2.1.5.

For orifice-, nozzle-, and venturi-type flowmeters, perform the required flowmeter accuracy test in accordance with 40 CFR 75, Appendix D, Section 2.1.5.1 or 2.1.5.2 or perform a transmitter accuracy test once every four fuel flowmeter QA operating quarter and a primary element visual inspection.

If a fuel flow-to-load test (40 CFR 75, Appendix D, Section 2.1.7) is performed during each operating quarter, subsequent to a required flowmeter accuracy test or transmitter accuracy test and primary element inspection, those procedures may be used to meet the periodic quality assurance requirement for a period of up to 20 calendar quarters from the previous accuracy test or transmitter accuracy tests and primary element inspection.

### 5.4.1 Certification Requirement for Fuel Flowmeters - (40 CFR 75, Appendix D, Section 2.1.5)

All fuel flowmeters must meet an initial certification flowmeter accuracy requirement of 2% of the upper range value (maximum calibrated fuel flow rate) across the range of the fuel flow rate. Flowmeter accuracy can be determined by design or measurement under laboratory conditions; by the manufacturer; by an independent laboratory or by the owner/operator. Flowmeter accuracy may also be determined against a NIST traceable reference method.

Alternately, the flowmeter accuracy can be determined by comparing it against the measured flow from a reference flowmeter that has been either designed according to the specifications of American Gas Association Report No. 3 or ASME MFC-3M-1989, or tested for accuracy during the previous 365 days, using a standard listed in 40 CFR 75, Appendix D, Section 2.1.5.1 or by a procedure pre-approved by the EPA Administrator. Any secondary elements, such as pressure and temperature transmitters, must be calibrated prior to the comparison. Perform the comparison over a period of no more than seven consecutive unit operating days. Compare the average of three fuel flow rate readings over 20 minutes or longer for each meter at each of three different flow rate levels. The three flow rate levels shall correspond to:

1. Normal full unit operating load
2. Normal minimum operating load
3. A load point approximately equally spaced between the full and minimum unit operating loads

Calculate the flowmeter accuracy at each of the three flow levels by the following (40 CFR 75, Appendix D, equation D-1):

$$ACC = \frac{|R - A|}{URV} x 100$$

Where:

| | | | |
|---|---|---|---|
| ACC | = | Flowmeter accuracy at a particular load level, as a percentage of the upper range value |
| R | = | Average of the three flow measurements of the reference flowmeter |
| A | = | Average of the three measurements of the flowmeter being tested |
| URV | = | Upper range value of the fuel flowmeter being tested |

If an in-place reference meter or prover is used for periodic quality assurance, the reference meter calibration requirement (calibration within 65 days prior to an accuracy test) may be waived if, during the previous in-place accuracy test with that reference meter, the reference meter and meter being tested agreed to within ± 1.0% of all levels tested. This exception will apply for a period of no longer than five consecutive years (20 consecutive calendar quarters).

If the flowmeter accuracy exceeds specifications, the flowmeter is considered out-of-control. Either recalibrate the flowmeter until accuracy is within specification, or replace with another flowmeter that has been proven to meet the accuracy specification. Substitute for fuel flow rate using missing data procedures until quality assured fuel flow data is available.

### 5.4.2 Transmitter or Transducer Accuracy Test

Calibrate the transmitter or transducer (as applicable) with equipment that has a current certificate of traceability to NIST standards. Check the calibration of the transmitter or transducer by comparing its readings to that of the certified equipment at least once at each of the following levels: the zero-level and at least two other levels (mid and high) such that the full range of the transmitter or transducer readings correspond to normal unit operation.

Calculate the accuracy of each transmitter or transducer at each level by the following (40 CFR 75, Appendix D, equation D-1a):

$$ACC = \frac{|R - T|}{FS} x 100$$

Where:

| | | |
|---|---|---|
| ACC | = | Accuracy of transmitter or transducer as a % of full-scale |
| R | = | Reading of the NIST traceably reference value |
| T | = | Reading of the transmitter or transducer |
| FS | = | Full-scale range of the transmitter or transducer being tested |

If each transmitter or transducer meets an accuracy of ±1.0% of full-scale range at each level tested, the fuel flowmeter accuracy of 2.0% is considered to be met at all levels. If the transmitter or transducer does not meet ±1.0% of full-scale range at a particular level, then a demonstration may be made that the fuel flowmeter meets the total accuracy specification of 2.0% at that level by one of the following methods. If, at a particular level, the sum of the individual accuracies of the three transducers is less than or equal to 4.0%, the fuel flowmeter accuracy specification if 2.0% is considered to be met at that level. Or, if at a particular level, the total fuel flowmeter accuracy is 2.0% or less, when calculated in accordance with Part 1 of "American Gas Association Report No. 3 General Equations and Uncertainty Guidelines", the flowmeter accuracy requirement is considered to be met for that level.

Record the accuracy of the orifice, nozzle, or venturi or it's individual transmitters or transducers and keep in a file at the site in a location suitable for inspection.

When testing individual orifice, nozzle, or venturi meter transmitters or transmitters, include the information as displayed in 40 CFR 75, Appendix D, Table D-2. At a minimum, record results for each transmitter or transducer at the zero-level and at least two other levels across the range of the transmitter or transducer that correspond to normal unit operation.

When accuracy testing of the orifice, nozzle, or venturi meter is performed in accordance with 40 CFR 75, Appendix D, Section 2.1.5.2, record the information as displayed in 40 CFR 75, Appendix D, Table D-1.

Report the results of all fuel flowmeter accuracy tests, transmitter or transducer accuracy tests, and primary element inspections, as applicable, in the required quarter emissions report for the quarter in which these tests were performed.

#### 5.4.2.1 Out-of-Control

If any accuracy test fails to meet the flowmeter accuracy specification of 2% at any of the load levels, then the fuel flowmeter is out-of-control. Repair or replace transmitter(s) or transducer(s) as needed until the flowmeter accuracy specification has been achieved at all levels.

Data from the fuel flowmeter are considered invalid from the hour of the failed accuracy test until the date and hour of a successful accuracy test. In addition, if during normal operation of the fuel flowmeter, one or more transmitters or transducers malfunction, data from the fuel flowmeter will be considered invalid from the hour of the failure to the hour of completion of a successful 3-level transmitter or transducer accuracy test. During fuel flowmeter out-of-control periods, provide data from another fuel flowmeter that meets the requirements of §75.20(d) and 40 CFR 75, Appendix D, Section 2.1.5. Alternately, substitute for fuel flow rate using the missing data procedures located in 40 CFR 75, Appendix D, Section 2.4.2. Record and report test data and results as applicable.

#### 5.4.2.2 Primary Element Inspection

Conduct a visual inspection of the orifice, nozzle, or venturi at least once every twelve calendar quarters. If a fuel flow-to-load procedure is utilized (40 CFR 75, Appendix D, Section 2.1.7), the frequency of inspection may be reduced to at least once every 20 calendar quarters.

The inspection may be performed using a baroscope. If the visual inspection indicates any damage or corrosion then replace or restore to an "as new" condition. After, determine the overall accuracy of the flowmeter using approved ASME methods.

During this period, provide data from another fuel flowmeter that meet all applicable specifications or substitute missing data procedures.

### 5.4.3 Fuel Flow-to-Load Quality Assurance Testing – (40 CFR 75, Appendix D, Section 2.1.7)

The following procedures may be used as an optional supplement to the quality assurance procedures in 40 CFR 75, Appendix D, Sections 2.1.5.1, 2.1.5.2, 2.1.6.1, or 2.1.6.2 when conducting periodic quality assurance testing of a certified fuel flowmeter. However, these procedures may not be used unless the 168-hour data requirement of 40 CFR 75, Appendix D, Section 2.1.7.1 has been met. If following a flowmeter accuracy test or flowmeter transmitter test and primary element inspection (as applicable), the following procedures are performed during each subsequent fuel flowmeter QA operating quarter, then these procedures may be used to meet the requirement for periodic quality assurance for a period of up to 20 calendar quarters from the previous quality assurance procedure performed in accordance with 40 CFR 75, Appendix D, Sections 2.1.5.1, 2.1.5.2, 2.1.6.1, or 2.1.6.2.

#### 5.4.3.1 Baseline Flow Rate-to-Load Ratio or Heat Input-to-Load Ratio

A baseline value of the ratio of fuel flow rate to unit load is determined. A baseline period of 168 hours of quality assured fuel flowmeter data is established. Baseline data collection begins with the first hour of fuel flowmeter operation following completion of the most recent quality assurance procedure(s). During baseline data collection, data may be excluded as non-representative any hour in which the unit is "ramping" up or down, (i.e., the load during the hour differs by more that 15% from the load in the previous or subsequent hour). Data may also be excluded for any hour in which the unit load is in the lower 25% of the range of operation (unless operation in this lower 25% of the range is considered normal for the unit). The baseline data must be collected no later than the end of the fourth calendar quarter following the calendar quarter of the most recent fuel flowmeter quality assurance procedure.

Calculate the baseline fuel flow rate-to-load ratio as follows (40 CFR 75, Appendix D, equation D-1b):

$$R_{base} = \frac{Q_{base}}{L_{avg}}$$

Where:

| | | | |
|---|---|---|---|
| | $R_{base}$ | = | Value of the fuel flowmeter rate-to-load ratio during baseline period |
| | $Q_{base}$ | = | Average fuel flow rate measured by the fuel flowmeter during baseline period |
| | $L_{avg}$ | = | Average unit load during the baseline period |

Alternately, a baseline value of the gross heat rate (GHR) may be determined in lieu of $R_{base}$. (40 CFR 75, Appendix D, Equation D-1c.)

$$(GHR)_{base} = \frac{(\text{Heat Input})_{avg}}{L_{avg}} \times 1000$$

Where:

| | | | |
|---|---|---|---|
| | $GHR_{base}$ | = | Baseline value of the gross heat rate |
| | Heat $\text{Input}_{base}$ | = | Average hourly heat input rate recorded by fuel flowmeter during baseline period |
| | $L_{avg}$ | = | Average unit load during the baseline period |

#### 5.4.3.2 Data Preparation

At the end of each fuel flowmeter QA operating quarter, use the following equations to calculate hourly fuel flow-to-load ratio or hourly gross heat rate (in lieu of the hourly flow-to-load ratio), for every quality assured hourly average obtained with a certified fuel flowmeter (40 CFR 75, Appendix D, equations D-1d and D-1e).

$$R_h = \frac{Q_h}{L_h}$$

Where:

| | | | |
|---|---|---|---|
| | $R_h$ | = | Hourly value of the fuel flow rate-to-load ratio |
| | $Q_h$ | = | Hourly fuel flow rate, as measured by the fuel flowmeter |
| | $L_h$ | = | Hourly unit load |

or use

$$(GHR)_h = \frac{(\text{Heat Input})_h}{L_h} \times 1000$$

Where:

| | | |
|---|---|---|
| $GHR_h$ | = | Hourly value of the gross heat rate |
| Heat $Input_h$ | = | Hourly heat input rate, as determined using the applicable equation in 40 CFR 75, Appendix F |
| $L_h$ | = | Hourly unit load |

Perform a separate data analysis for each fuel flowmeter. Base each analysis on a minimum of 168 hours of data. If fewer that 168 hourly flow-to-load ratios (or GHR) are available, then an evaluation is not required for that flowmeter for that calendar quarter.

Calculate the percentage difference from the baseline fuel flow-to-load ratio using the following (40 CFR 75, Appendix D, equation D-1f):

$$\%D_h = \frac{|R_{base} - R_h|}{R_{base}} x\,100$$

Where:

| | | |
|---|---|---|
| $\%D_h$ | = | Absolute value of the % difference between the hourly fuel flow rate-to-load ratio and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR) |
| $R_h$ | = | Hourly fuel flow rate-to-load ratio (or GHR) |
| $R_{base}$ | = | Value of the fuel flow rate-to-load ratio (or GHR) from the baseline period |

Next, determine the arithmetic average of all the hourly percent difference (percent $D_h$) values using the following (40 CFR 75, Appendix D, D-1g):

$$E_f = \sum_{h=1}^{q} \frac{\%D_h}{q}$$

Where:

| | | |
|---|---|---|
| $E_f$ | = | Quarterly average percentage difference between hourly flow rate-to-load ratios and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR) |
| $\%D_h$ | = | Percentage difference between the hourly fuel flow rate-to-load ration and the baseline value of the fuel flow rate-to-load ratio or hourly and baseline GHR) |
| q | = | Number of hours used in fuel flow-to-load (or GHR) evaluation |

When the quarterly average load value used in the data analysis is greater than 50 MWe (or 500 klb steam per hour), the results of a quarterly fuel flow rate-to-load (or GHR) evaluation is acceptable. No further action is required if the quarterly average percent difference ($E_f$) is no greater than 10%. When the arithmetic average of the hourly load values used in the data analysis is ≤50 MWe (or 500 klb steam per hour), the value of $E_f$ is no greater than 15%.

### 5.4.3.3 Optional Data Exclusions

If $E_f$ is outside of allowed limits, the hourly fuel flow rate-to-load ratios (or GHRs) may be re-examined. Identify and exclude any non-representative fuel flow-to-load ratios or GHRs. These exclusions can include any hour in which the unit combusted another fuel in addition to the fuel measured by the fuel flowmeter being tested; or any hour for which the load differed by more than 15% from the load during either the preceding or subsequent hour; or any hour for which the unit load was in the lower 25% of the range of operation (unless this 25% of the range is considered normal for that unit).

After re-examining and excluding non-representative data, analyzer the quarterly fuel flow rate-to-load data a second time.

#### 5.4.3.4 Out-of-Control

If $E_f$ is outside of the applicable limit, perform transmitter accuracy tests in accordance with 40 CFR 75, Appendix D, Section 2.1.6.1 or perform a fuel flowmeter accuracy test in accordance with 40 CFR 75, Appendix D, Section 2.1.5.1 or 2.1.5.2. In addition, repeat the fuel flow-to-load comparison using six to twelve hours of data following a passed transmitter accuracy test to verify that no significant corrosion has affected the primary element. If the abbreviated 6-12 hour test does not meet the applicable limit, then perform a visual inspection of the primary element and repair or replace as needed.

Substitute for fuel flow rate, for any hour when that fuel is combusted, using missing data procedures in 40 CFR 75, Appendix D, Section 2.4.2, beginning with the first hour of the calendar quarter following the quarter for which $E_f$ was found to be outside of the applicable limit and continuing until quality assured fuel flow data becomes available.

Following a failed flow rate-to-load or GHR evaluation, data from the flowmeter will not be considered as quality assured until the hour in which all required flowmeter accuracy tests, transmitter accuracy test, visual inspections and diagnostic tests have been passed. Additionally, a new $R_{base}$ or $(GHR)_{base}$ will be established no later than two flowmeter QA operating quarters after the quarter in which the required quality assurance tests are completed.

#### 5.4.3.5 Test Results

Report the results of each quarterly flow rate-to-load (of GHR) evaluation in the electronic quarterly report as required under §75.64.

**Table 5-1. Typical Quarterly Linearity Audit Calibration Gas Concentrations**

| **$O_2$ Analyzer: Measurement Range = 0-25%** | **Gas Concentration** |
|---|---|
| Low (20 to 30% of span) | 5 - 7.5% |
| Mid (50 to 60% of span) | 12.5 - 15% |
| High (80 to 100% of span) | 20 - 25% |

The low range of the $NO_X$ analyzer is exempt from the linearity test requirement.

| **$NO_x$ Analyzer: Measurement Range = 0-100 ppm** | **Gas Concentration** |
|---|---|
| Low (20 to 30% of span) | 20 - 20 ppm |
| Mid (50 to 60% of span) | 50 - 60 ppm |
| High (80 to 100% of span) | 80 - 100 ppm |

**NOTE: All calibration gases used for linearity must be Protocol 1 gases.**

NOTE: Do not use gas cylinders if the pressure has fallen below 150 psig.

Table 5-2. Linearity Error Determination Example Form

| Audit Point | Date | Reference Gas Value | Monitor Reading | Difference |
|---|---|---|---|---|
| Low 1 | | | | |
| Low 2 | | | | |
| Low 3 | | | | |
| Average of three challenges for low level | | | | |
| % of Reference Value | | | | |
| Mid 1 | | | | |
| Mid 2 | | | | |
| Mid 3 | | | | |
| Average of three challenges for mid level | | | | |
| % of Reference Value | | | | |
| High 1 | | | | |
| High 2 | | | | |
| High 3 | | | | |
| Average of three challenges for high level | | | | |
| % of Reference Value | | | | |

**Table 5-3. Relative Accuracy Determination for Gas Analyzers Example Form**
(Refer to 40 CFR 75, Appendix A, Figure 2.)

Unit No.________ Range ________
Gas ________ Load ________

| Run | Date | Time (Start/End) | Reference Method | Monitor Reading | Difference |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | | | | | |
| 3 | | | | | |
| 4 | | | | | |
| 5 | | | | | |
| 6 | | | | | |
| 7 | | | | | |
| 8 | | | | | |
| 9 | | | | | |
| 10 | | | | | |
| 11 | | | | | |
| 12 | | | | | |
| | | | | Average RM | |
| | | | | Average Difference | |
| | | | | Number of Runs | |
| | | | | Standard Deviation | |
| | | | | T-Value | |
| | | | | Confidence Coefficient | |
| | | | | Relative Accuracy % | |

**Table 5-4. Relative Accuracy Determination Example Form - $NO_x$/Diluent ($O_2$)**
(Refer to 40 CFR 75, Appendix A, Figure 4.)

Unit No. ________
Date ________
Range ________
Load ________

| Run | Time (Start/End) | RM $NO_X$ ppm | RM ($O_2$%) | RM $NO_X$ lb/MMBtu | CEMS $NO_x$ lb/MMBtu | Difference |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |
| 11 | | | | | | |
| 12 | | | | | | |
| | | | | | Average RM | |
| | | | | | Average Difference | |
| | | | | | Number of Runs | |
| | | | | | Standard Deviation | |
| | | | | | T-Value | |
| | | | | | Confidence Coefficient | |
| | | | | | Relative Accuracy, % | |

**Table 5-5. Table of Flowmeter Transmitter or Transducer Accuracy Results**
(40 CFR 75, Appendix D, Table D-2)

Test #: ______________ Test Completion Date: __________ Unit or Pipe ID: ______________
Flowmeter S/N: ________ Component/System ID: ________
Full-scale Value: _______ Units of Measure: ____________

Transducer/Transmitter Type (check one):
_______Differential Pressure
_______Static Pressure
_______Temperature

| Measurement Level (percent of full-scale) | Run number | Run time (HHMM) | Transmitter/ transducer input (pre-calibration) | Expected transmitter/ transducer output (reference) | Actual transmitter/ transducer output | Percent accuracy (percent of full-scale) |
|---|---|---|---|---|---|---|
| Low (minimum) level percent of full-scale | | | | | | |
| Mid-level percent of full-scale (If tested at more than 3 levels) | | | | | | |
| 2nd Mid-level percent of full-scale (If tested at more than 3 levels) | | | | | | |
| 3rd Mid-level percent of full-scale (If tested at more than 3 levels) | | | | | | |
| High (maximum) level percent of full-scale | | | | | | |

At a minimum, it's required to test at zero-level and at least two other levels across the range of the transmitter or transducer readings corresponding to normal unit operation.

It is required to test at least once at each level.

Use the same units of measure for all readings (e.g., use degrees (°), inches of water ($H_2O$), pounds per square inch (psi), or milliamperes (ma) for both transmitter or transducer readings and reference readings).

### Table 5-6. Table of Flowmeter Accuracy Results
(40 CFR 75, Appendix D, Table D-1)

Test #: ______________ Test Completion Date: ________ Test Completion Time: ________
Reinstallation date[2] (for testing under 2.1.5.1 only): ______________ Reinstallation time[1]: ________
Unit or pipe ID: _______ Component/System ID: ________
Flowmeter S/N: _______ Upper Range Value: __________
Units of measurement for flowmeter and reference flow readings: ________________

| Measurement level (% of URV) | Run No. | Time of run (HHMM) | Candidate flowmeter reading | Reference flow reading | % accuracy (% of URV) |
|---|---|---|---|---|---|
| Low (minimum) level ___%[3] of URV | 1 | | | | |
| | 2 | | | | |
| | 3 | | | | |
| | Average | | | | |
| Mid (minimum) level ___%[3] of URV | 1 | | | | |
| | 2 | | | | |
| | 3 | | | | |
| | Average | | | | |
| High (minimum) level ___%[3] of URV | 1 | | | | |
| | 2 | | | | |
| | 3 | | | | |
| | Average | | | | |

[1] Report the date, hour, and minute that all test runs were completed

[2] For laboratory tests not performed inline, report the date and hour that the fuel flowmeter was reinstalled following the test.

[3] It is required to test at least at three different levels: (1) normal unit operating load, (2) normal minimum unit operating load, and (3) a load point approximately equally spaced between the full and minimum unit operating loads.

Table 5-7. Baseline Information and Test Results for Fuel Flow-to-Load Test
(40 CFR 75, Appendix D, Table D-1)

Plant Name: ____________ State: ________ ORIS Code: ________
Unit/pipe ID: ____________ Fuel flowmeter component/system ID: ____________
Calendar quarter (1st, 2nd, 3rd, 4th) and year: ____________
Range of operation: ________ to ____________ MWe or klb steam/hr (indicate units)

| Time period | |
|---|---|
| Baseline period | Quarter |
| Completion date and time of most recent primary element inspection (orifice, nozzle, and venturi-type flowmeters only):<br><br>___/___/___ ___:___ | Number of hours excluded from quarterly average due to co-firing different fuels:<br><br>____ hours |
| Beginning date and time of baseline period:<br><br>___/___/___ ___:___ | Number of hours in the lower 25% of the range of operation excluded from quarterly average:<br><br>____ hours |
| End date and time of baseline period<br><br>___/___/___ ___:___ | Quarterly percentage difference between hourly ratios and baseline ratio:<br><br>_____ % |
| Average load: _____ (MWe or 1000 lb steam/hr)<br>Baseline fuel flow-to-load: ______<br>Baseline GHR: ____<br>Units of fuel flow-to-load: ____<br>Number of hours excluded from baseline ration or GHR due to ramping load: ____<br>Number of hours in the lower 25% of the range of operation excluded form baseline ratio or GHF:<br>_____ hours | Test result: pass, fail |

# 6.0 ROUTINE PREVENTIVE MAINTENANCE

In accordance with 40 CFR 75, Appendix B, Section 1.3, the source owner or operator must keep a written record of procedures needed to maintain the CEMS in proper operating condition and a schedule for these procedures.

## 6.1 Frequency of Checks

The following is the schedule of checks that must be followed to ensure reported data is reliable and the CEMS operates dependably. The following includes information about when checks and audits should be performed and when a situation indicates the need for corrective actions. It is essential the personnel conducting the checks and audits completely fill out every item on the appropriate forms. This includes the recording of any comments concerning the condition of the CEMS. Corrective actions should be initiated immediately upon identification of a problem or malfunction.

It is recommended that zero and span calibration drift checks be conducted immediately prior to any maintenance and a calibration must be performed after any maintenance. If the post-maintenance zero or calibration drift test shows excessive drift, correction action and recalibration must be conducted to bring the CEMS and its components within specifications. All corrective action activities must be documented. Refer to Table 6-1 for an example of a Corrective Action Report Sheet.

## 6.2 Corrective Actions Requiring Recertification

According to 40 CFR 75, Subpart C, Section 75.20(5(b)), any change that affects the monitors measuring systems or analysis systems in such a way that measurements or calibrations have changed significantly (including the DAHS), triggers a recertification. Change resulting from routine or normal corrective maintenance and/or quality assurance activities do not require recertification, nor do software modifications in the automated data acquisition and handling system, where the modification is only for the purpose of generating additional or modified reports for the State Implementation Plan (SIP) or for reporting requirements under 40 CFR 75 Subpart G.

The following are examples of situations that require recertification. These changes include, but are not limited to:

- changes in gas cells
- path lengths
- sample probe
- system optics
- replacement of analytical methods (including the analyzer(s), monitor(s))
- change in location or orientation of the sampling probe or site
- rebuilding of the analyzer or all monitoring system equipment

These changes may require EPA notification and recertification. Replacement of analyzers in total will require recertification unless the analyzer was previously certified as a backup for a given CEM under the following conditions:

1. The backup system has been certified at the same sampling location within the previous two calendar quarters.
2. All components of the backup system have previously been certified.
3. Component monitors of the backup system pass a linearity check (for pollutant monitors) prior to their use for monitoring of emissions.

In addition, if a CEMS system has not operated for more than 2 calendar years, then the owner or source operator shall recertify the CEMS system.

Recertification of the CEMS may also be triggered if the owner/operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that significantly changes the flow or concentration profile of the monitored emissions.

For recertification testing, the owner/operator shall re-perform all initial certification tests as outlined in the site's original certification test protocol (located under separate cover), as approved by the local Administrator. Approval and notice of recertification test dates must be obtained by petition or may be provided in written guidance from the Administrator.

### 6.3 Logbook Maintenance

A logbook will be kept and maintained to track all scheduled and unscheduled maintenance, calibration gas bottle pressures and any other anomalies or information relevant to the history of the individual CEMS. This will also serve as a record of maintenance performed to manufacturers' instructions for warranty purposes.

### 6.4 Preventive Maintenance

This section contains suggestions for performing routine preventive maintenance. For detailed maintenance procedures refer to the manufacturers' instruction manuals and other technical data included under separate cover(s).

#### 6.4.1 Calibration Failure

One of the best indicators of system performance is the validity of the data being generated. The CEMS and the component analyzers are programmed to conduct a daily calibration check once every 24 hours. Daily scrutiny of these results will indicate whether maintenance will be needed.

If a calibration failure occurs, first check the gauge on the related calibration gas cylinder to see if the pressure is adequate. If the gas pressure is adequate, manually perform a calibration. If a calibration cannot be successfully completed by adjusting the analyzers, troubleshoot and perform maintenance as required on the analyzer

It's recommended that a zero and span calibration drift check be performed immediately prior to any maintenance and a calibration must be performed after any maintenance. If the post maintenance calibration drift test shows excessive drift, corrective action and recalibration must be conducted to bring the CEMS within specifications. All corrective actions must be fully logged and documented.

#### 6.4.2 Excessive Zero Drift

If a calibration failure requires a substantial readjustment of the zero calibration on an analyzer, and if subsequent automatic calibrations indicate a widely drifting zero output, troubleshoot and service that analyzer following the procedures in the manufacturer's instruction manual.

#### 6.4.3 Abnormal Measurement Output Voltage

If output voltage range is not between the required range for each analyzer and calibration is completed successfully, refer to the manufacturer's instruction manuals for adjustment and repair information.

#### 6.4.4 Water Contamination

Following a sample failure alarm, first check for any water in line or a high cooler temperature. To find the cause of the water contamination, proceed as follows:

1. Check to see that the temperature of the sample gas cooler is 35°F.
2. Remove, dry out, and replace the conductivity sensor (CS1) filter elements.

### 6.5 Routine Maintenance for the Sample Probe

The probe has no moving parts. It does have a particulate filter and an electric heater. The electric heater can be checked by using a clamp-on AC amp meter to detect current on the power wires going from the analyzer cabinet into the sample line up to the probe. The probe also has a low temperature alarm contact that will detect an inoperable probe heater. The filter is manually checked as part of scheduled routine maintenance as described later.

### 6.6 Routine Maintenance for the Sample Line

The sample line requires no maintenance. However, it is advisable to periodically inspect the sample line visually to detect any damage or wear due to rubbing, vibration, physical damage, etc. If the sample line is installed properly there should be no stress points which could cause the tubing to become kinked in any manner. Typical life of the sample line heat trace is approximately 10-12 years depending on the temperature maintained and ambient conditions. Sample line heat trace is not a serviceable item and thus would require replacement in its entirety.

### 6.7 Routine Maintenance for the Sample Conditioning Unit

The sample-conditioning unit has several items that are part of the system maintenance requirements as follows:

1. Filters – Visually inspect through glass housing
2. Insure sample pump is operating properly
3. Insure condensate pump is operating correctly

### 6.8 Preventive Maintenance Schedule

This section contains a suggested schedule for performing preventive maintenance. Maintenance schedules may vary depending upon site-specific conditions (i.e., filters may need to be changed more often in a "dirty" environment or less often under "clean" conditions). For detailed maintenance procedures refer to the manufacturer's instruction manuals and other technical data included separate cover.

Some items, such as filter checks, may not exhibit a failure condition until damage has occurred to other components. Initially, these items will require careful and frequent checking to determine replacement frequency specific to individual applications. Any changes of the operating characteristics of the system should trigger a maintenance response to prevent loss of data and/or equipment damage. This includes paying attention to any shift (sudden or prolonged) in one direction and close observation of the visual indicators in the system.

CEMS alarms indicate that service is required. They do not necessarily indicate that the collected data is invalid. The alarms do indicate that the system is operating outside of design tolerance and incorrect data and equipment damage will occur if the system continues operation without corrective action. For this reason, the alarms themselves should be tested on a regular basis to assure that they are operating as designed. All alarm conditions require quick attention and resolution.

### 6.8.1 Daily Preventive Maintenance Check Form Example

Unit No.: _______ Date: _______

| ITEM | INITIALS | RECORD VALUES WHERE APPLICABLE | COMMENTS |
|---|---|---|---|
| **SAMPLE SYSTEM** | | | |
| Check sample pressure and vacuum. | | | |
| Record sample flow - total flow meter (cc/minute). | | | |
| Record each analyzer's flow meter (cc/minute). | | | |
| Visually inspect particulate filter. If the filter shows buildup and flow levels are dropping, replace filter. | | | |
| Check sample cooler temperature alarm. | | | |
| Record calibration bottle pressures. | | | |
| **DAHS** | | | |
| Check/verify Daily Report and Calibration Report. | | | |
| Check printer and/or recorder for on-line, paper faults, and ribbon/ink. | | | |
| **TECO MODEL 42C $NO_x$** - Daily | | | |
| Check calibration results. | | | |
| **SERVOMEX MODEL 1440C $O_2$** - Daily | | | |
| Observe display for error messages. | | | |

### 6.8.2 Weekly Preventive Maintenance Check Form Example

Unit No.: _______ Date: _______

| ITEM | INITIALS | RECORD VALUES WHERE APPLICABLE | COMMENTS |
|---|---|---|---|
| **SAMPLE SYSTEM** | | | |
| Perform daily checks. | | | |
| Perform manual calibration and adjust analyzers as needed. | | | |
| Check moisture sensor and tubing downstream of sample conditioner for moisture – Remove and dry as necessary. Investigate sample conditioner for proper operation. | | | |
| Check all filters, replace as necessary (usually every two to three months). | | | |
| **TECO MODEL 42C $NO_x$** - Weekly | | | |
| Perform Zero and Span adjustment, if required. | | | |
| Check desiccant at $NO_x$ analyzer. Color changes from blue to pink as desiccant absorbs moisture. Replace as necessary (usually every three months). | | | |

### 6.8.3 Monthly Preventive Maintenance Check Form Example

Unit No.: _______ Date: _______

| ITEM | INITIALS | RECORD VALUES WHERE APPLICABLE | COMMENTS |
|---|---|---|---|
| SAMPLE SYSTEM | | | |
| Perform Weekly Maintenance. | | | |
| Check sample pump, replace diaphragms, and disks as needed (usually every 4 months). | | | |
| Check peristaltic pump tubing, replace as necessary. | | | |
| Change desiccant media. | | | |
| Perform sample system leak check. | | | |

## 6.8.4 Quarterly Preventive Maintenance Check Form Example

Unit No.: _______ Date: _______

| ITEM | INITIALS | RECORD VALUES WHERE APPLICABLE | COMMENTS |
|---|---|---|---|
| **SAMPLE SYSTEM** | | | |
| If sample gas pressure shows a decline, perform probe maintenance. Replace the filter element and clean filter chamber as necessary. Verify probe box heater is operating. If flow is low, check sample pump. | | | |
| Verify and calibrate all CEMS alarm switches. | | | |
| Perform Weekly and Monthly Maintenance. | | | |
| **TECO MODEL 42C $NO_x$** - Quarterly | | | |
| Check pump diaphragm and Teflon wafer, rebuild as needed (every 4 months) | | | |
| Inspect sample filter, replace if needed. | | | |
| Inspect ozone reducing capillary for blockage (discoloration). The capillary should be clear, if not replace. | | | |
| Inspect sample reducing capillary for blockage (discoloration). The capillary should be clear, if not replace. | | | |
| Insect capillary O-rings for wear, replace if needed. | | | |
| Inspect ozone generator and scrubber. | | | |
| **SERVOMEX MODEL 1440C $O_2$** - Quarterly | | | |
| Replace the filter element, located in the Automatic flow control device on the rear panel. (This period may be extended for clean samples.) Adjust 4-20 ma outputs to match LED display. | | | |

### 6.8.5 Semi-Annual Preventive Maintenance Check Form Example

Unit No.: _______ Date: _______

| ITEM | INITIALS | RECORD VALUES WHERE APPLICABLE | COMMENTS |
|---|---|---|---|
| **SAMPLE SYSTEM** | | | |
| Perform Quarterly Maintenance. | | | |
| **TECO MODEL 42C $NO_x$** - Semi-Annual | | | |
| Perform digital to analog converter test when a problem with the analog outputs is suspected. | | | |
| Inspect and clean cooler fins on the PMT. | | | |
| Inspect and clean fan filters. | | | |

### 6.8.6 Annual Preventive Maintenance Check Form Example

Unit No.: _______ Date: _______

| ITEM | INITIALS | RECORD VALUES WHERE APPLICABLE | COMMENTS |
|---|---|---|---|
| SAMPLE SYSTEM | | | |
| Perform Quarterly Maintenance. | | | |

Table 6-1. Corrective Action Report Sheet – Example

Date: ______________________ Initials: ______________________
Time: ______________________ Reviewed By: ______________________
Locations: ______________________ Unit: ______________________

Analyzer/Monitor/Component Being Serviced: ______________________

Problem (Describe the problem that initiated the corrective action, including active alarms, out-of-control conditions etc.):

______________________
______________________
______________________
______________________
______________________
______________________

Corrective Action (Describe the procedures, checks, tests, etc. performed to correct the problem. Include a list of parts used.):

______________________
______________________
______________________
______________________
______________________
______________________

As Corrected Condition (Describe the state of the analyzer/monitor/component/system following corrective action. Include alarms cleared, calibration results, analyzer readings, etc.):

______________________
______________________
______________________
______________________
______________________
______________________
______________________

# 7.0 CORRECTIVE MAINTENANCE

This section contains information on performing troubleshooting and corrective maintenance. For detailed procedures refer to the manufacturer's instruction manuals and other technical data included under separate cover. The technician should be familiar with the material in these manuals before attempting any troubleshooting.

## 7.1 Troubleshooting the CEMSCAN System

| Problem | Corrective Action |
|---|---|
| Power failure. | 1. Check circuit breakers.<br>2. Check power wiring.<br>3. Check alarm system. |
| Heat-trace failure. | 1. Check sample line temperature.<br>2. Check voltage/current for heated sample line<br>3. Check line for external damage. |
| Loss of sample. | 1. Check sample pump motor, wiring, diaphragm and seals.<br>2. Check sample vacuum and pressure.<br>3. Check setpoint at pressure for 3 psi<br>4. Check sample gas cooler.<br>5. Check moisture/conductivity sensor.<br>6. Adjust back pressure regulator.<br>7. Check gauges for sticking or fouling.<br>8. Check filters and sample line for blockage/leaks, proper connection.<br>9. Check analyzer vents for blockages.<br>10. Remove, clean, repair or replace sample line components causing flow restrictions |
| High Vacuum. | 1. Check probe for blockage.<br>2. Check sample line for blockage.<br>3. Replace vacuum switch. Using ohmmeter, run switch up and down watching vacuum gauge or trip point; watch ohmmeter for contact closure. |
| Water in Line. | 1. Check temperature alarm of sample gas cooler<br>2. Check sample line heating.<br>3. Peristaltic drain pump is inoperative.<br>4. Solid state switch in conductivity sensor needs replacing. |
| Instrument air loss. | 1. Check instrument air supply.<br>2. Check for proper setpoint. |
| Calibration Gas Cylinder Pressure. | 1. Check regulator gauges.<br>2. Install new cylinders. |

### 7.1.1 Leak Check Procedure

This leak check procedure should be done once a year or whenever a leak is suspected.

1. Place the system in Maintenance Request.
2. Make sure sample pump is on.
3. Perform a manual calibration through the probe (remote cal.). Manually flow $NO_x$ span gas (balance of Nitrogen).
4. Watch $O_2$ analyzer reading.
5. $O_2$ analyzer should read <0.1%.
6. If system fails the test in step 5, plug line on inlet side of sample gas cooler and repeat steps 3-5, except perform a local calibration.
7. If system passes the test in step 6, check sample line, probe check valve, and probe filter housing. Troubleshoot and repair as required.

**NOTE:** Pressure side leaks are not covered by this check and are best found with "Snoop" or other leak detection liquid.

### 7.1.2 Flow Balance Procedure

1. In the Sample Mode, set back pressure regulator to 5 psi as indicated on pressure gauge.
2. Adjust rotameters for 1 liter per minute.
3. Continue steps 1 and 2 until adjusted.
4. Perform a manual calibration.
5. Adjust trim valve to midrange.
6. Adjust pressure on calibration gas bottle 1 to achieve 10 psi as indicated by pressure gauge.
7. Ensure rotameters stay at 1 liter per minute.
8. While calibration gas 2 is flowing adjust the bottle pressure for 10 psi as indicated by pressure gauge.
9. Do this for all remaining calibration gas bottles.
10. Return to the Auto Sampling Mode and check for 10 psi at pressure gauge and 1 liter per minute at the rotameters. If not, repeat System Flow Balance Procedure.

## 7.2 Troubleshooting the DAHS

The following table should help resolve simple problems that may occur from time to time.

| Problem | Probable Cause | Solution |
|---|---|---|
| System screen blank or dark | The system may be turned off, or the monitor may be turned off, unplugged or defective. | Verify that the system and monitor power cords are plugged in. Verify that the system and monitor power switches are turned on and the small (generally green) status lights are lit. If system is plugged in and turned on, and status lights are not lit; contact Customer Support. |
| System power switches are on, the system is plugged in, (system and monitor status lights are lit) but system does not respond to the keyboard entries. | The keyboard may be unplugged or defective. | Verify that the keyboard is plugged into the back of the computer. If the keyboard is plugged in; contact Customer Support. |
| Unreadable characters in filenames in the root or modem directory. | The modem has been reconfigured. | Contact your System Administrator or KVB-Enertec Customer Service to reconfigure your modem. CAUTION: Changing the settings on the modem can result in unpredictable commands being executed, typically creating zero length files with random filenames. This may also result in the loss of data. |
| Printer does not print reports. | Printer may be out of paper. Set OFFLINE; turned OFF, or unplugged. | Check printer status. The printer status light should be ON. If printer status light is OFF, press the ONLINE button to reset the printer. |

## 7.3 Troubleshooting the TECO Model 42C Analyzer

NOTE: Power should be removed from the instrument before any corrective maintenance is performed.

| Malfunction | Cause | Solution |
|---|---|---|
| Does Not Start Up | No power | Is instrument plugged in properly |
| | | Check fuse |
| | Power Supply | Check voltages |
| | Digital electronics | Unplug power cord. Check that all boards are seated properly. Replace one board at a time with known good board. |
| No Output Signal (or very low output) | No sample reaching analyzer | Check input sample flow |
| | Block sample capillary | Unplug power cord. Clean or replace capillary. |
| | No ozone reaching the reaction chamber | Check to see that ozonator is ON |
| | | Check Dry Air supply |
| | Disconnected or defective input or HV supply | Unplug power cord. Check that cables are connected properly |
| | | Check resistance of cables |
| | Analyzer not calibrated | Recalibrate |
| | Defective ∀ 15 volt | Check supply voltages |
| Excessive noise | Defective or low sensitivity PMT | Unplug power cord. Install known good PMT and check performance |
| | Defective cooler | Check background values (< 15 ppb) and temperature (< -2EC at $T_{amb}$ = 25EC) |
| Calibration Drift | Dryer to ozonator depleted | Replace |
| | Line voltage fluctuations | Check to see if line voltage is within specifications |
| | Unstable NO or $NO_2$ source | Replace |
| | Clogged capillaries | Unplug power cord. Clean or replace capillary. |
| | Clogged sample air filter | Replace filter element |

| | | |
|---|---|---|
| Nonlinear response | Incorrect calibration source | Verify accuracy of multipoint calibration source gas |
| | Leak in sample probe line | Check for variable dilution. Perform leak check. |
| Excessive response time | Partially blocked sample capillary | Unplug power cord. Clean or replace capillary |
| | Hang up in sample filter | Replace filter element |
| Improper converter operation | Incorrect calibration gas value | Verify accuracy |
| | Converter temperature too high or too low | Temperature should be about 325°C |
| | Low line voltage | Check that line voltage is within specifications. |
| | Molybdenum consumed | Replace converter |

NOTE: After any analyzer corrective preventive maintenance that may change analyzer performance, the CEM should be recalibrated.

## 7.4 Troubleshooting the Servomex Model 1440C $O_2$ Analyzer

Servomex recommends that only the manufacturer service the Model 1440C or qualified technicians.

## 8.0 RECOMMENDED SPARE PARTS LIST

To ensure the highest level of system availability and performance, KVB-Enertec, Inc. recommends that certain supplies and essential components be stocked at the CEM facility.

Parts lists, arranged by frequency of use and overall impact on the CEMS, are appended in this Section. For current spare parts pricing, call the KVB-Enertec, Inc. Parts Department (the toll-free number is listed in table of contents of this manual).

**Level A - Consumable Supplies**

Consumable supplies are spare parts that will require regular replacement over the life of the equipment.

**Level B - Basic Spare Parts**

Basic spare parts occasionally require replacement over the life of the equipment. These parts usually need to be replaced within a time frame of one to three years.

**Level C - Critical Repair Items**

Spare parts belonging to this group are generally very reliable, however, should these parts fail they would contribute to system downtime.

**Level D - In Depth Repair Items**

Included in this group are low failure rate components that are important for optimum system performance.

# EN 3192 JACKSONVILLE ELECTRIC AUTHORITY
## Brandy BranchTurbine Project
## Two Cemscan System

Recommended Spare Parts

2/15/01

Level A - Consumable Supplies (One Year Supply)

| Qty | P/N | Description | Frequency | Component |
|---|---|---|---|---|
| 1 | 25638 | Battery, For DB Module | Yearly | A/B SLC 500 PLC |
| 8 | 15121 | Capillary, 058 Mil-L | Quarterly | NOX 42CHL |
| 8 | 15117 | Capillary, 10 MIL L. | Quarterly | NOX 42CHL |
| 1 | 26266 | Fuse, 3 Amp Slo-Blo Pk/5 | Yearly | NOX 42CHL |
| 2 | 26259 | Pump Rebuild Kit, Vaccum | Yearly | NOX 42CHL |
| 1 | 15108-R | Capillary O-ring (pkg 10) | Yearly | NOX 42CHL |
| 5 | 20-008 | Ac Supply Fuse 2a | Yearly | 1440C-Servomex |
| 2 | 63023 | Moisture Sensor Element | Yearly | Sample System |
| 2 | 70035 | Filter, Porous Metal 12" ss | Yearly | Sample System |
| 2 | 12208 | Filter Elment for regulator | Yearly | Sample System |
| 2 | 12323-Jug | Silica Gell 5lb jug | 60 Days | Sample System |
| 2 | 12322-Jug | Desicant 5lb Jug | 60 Days | Sample System |
| 12 | 12815 | Sample Pump Diaphragm | 60 Days | Samp. Pump |
| 12 | 12865 | Sample Pump Gasket | 60 Days | Samp. Pump |
| 24 | 12866 | Sample Pump Disks (2) | 60 Days | Samp. Pump |
| 25 | 17062 | Tubing, Size 15, Black (Per Foot) | 60 Days | Peristaltic Pump |

Due upon receipt F.O.B. Rancho Santa Margarita, CA

# EN 3192 JACKSONVILLE ELECTRIC AUTHORITY

## Brandy BranchTurbine Project

Recommended Spare Parts

2/15/01

### Level B - Basic Spare Parts

| Qty | P/N | Description | MTBF | Component |
|---|---|---|---|---|
| 1 | 20-050 | AFCD Filter Element Kit | 1-2 Years | 1440C-Servomex |
| 1 | 20-002 | Front Swithcing PCB | 1-2 years | 1440C-Servomex |
| 1 | 20-003 | Main Control PCB | 1-2 years | 1440C-Servomex |
| 1 | 20-006 | Low Flow Sensor | 1-2 years | 1440C-Servomex |
| 1 | 20-007 | Automatic Flow Control Device | 1-2 years | 1440C-Servomex |
| 1 | 20-009 | Led Display Module | 1-2 years | 1440C-Servomex |
| 1 | 20-010 | Sample Plumbing Kit | 1-2 years | 1440C-Servomex |
| 1 | 70035 | Filter, SS 5 Micron | 1-2 Years | KVB Probe |
| 1 | 70125 | Heater 500 watts | 1-2 Years | KVB Probe |
| 5 | 12203 | Seal Kit, Ball Valve | 1-2 Years | KVB Probe |
| 2 | 12231 | O-Ring,PPL Filter | 1-2 Years | Samp. Pump |
| 1 | 70035 | Filter, Porous Metel 12" ss | 1-2 Years | Samp. Pump |
| 1 | 12803 | Dual Purpose Water Pump | 1-2 Years | Condenser |

### Level C - Critical Repair Items

| Qty | P/N | Description | MTBF | Component |
|---|---|---|---|---|
| 1 | 31-004 | Solenoid Valve, 3 Valve Manifold | 3-5 Years | Samp. System |
| 1 | 26234 | Ozonater Assy | 3-5 Years | NOX 42CHL |
| 1 | 26233 | Transformer Assy | 3-5 Years | NOX 42CHL |
| 1 | 25648 | Power Supply 5 amp | 5-10 Years | A/B SLC 500 PLC |
| 1 | 25647 | Digital Input A-B | 5-10 Years | A/B SLC 500 PLC |
| 1 | 25650 | Analog In A-B | 5-10 Years | A/B SLC 500 PLC |
| 1 | 25664 | Module Digital Output 16Pt | 5-10 Years | A/B SLC 500 PLC |

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# EN 3192 JACKSONVILLE ELECTRIC AUTHORITY

Recommended Spare Parts

## Brandy BranchTurbine Project

2/15/01

### Level D - In Depth Repair Items

| Qty | P/N | Description | MTBF | Component |
|---|---|---|---|---|
| 1 | 12172 | 3 Way 1/4" SS Ball Valve | 3-5 Years | KVB Probe |
| 1 | 12175 | Actuator, 3 Way Ball Valve | 3-5 Years | KVB Probe |
| 1 | 12730 | Pump Motor, Fixed Speed 6RPM | 5-10 Years | Peristaltic Pump |
| 1 | 12731 | Pump Head | 5-10 Years | Peristaltic Pump |
| 1 | 71026 | Switch, Temperature Setpt 280F | 5-10 Years | Sample System |
| 1 | 12514 | Regulator 2 Stage , BR w/gauges | 5-10 Years | Sample System |
| 1 | 12531 | Regulator 2 Stage , SS w/gauges | 5-10 Years | Sample System |
| 1 | 36-007 | Power Supply 24vdc 4 amp | 5-10 Years | Sample System |
| 1 | 14915 | Level Controller, Moisture Sensor | 5-10 Years | Sample System |
| 1 | 12334 | 2 Stream Condenser w/pump no HV | 5-10 Years | Sample System |
| 1 | 12721 | Sample Pump, ADI 316 SS | 2-5 Years | Samp. Pump |
| 1 | 20-109 | Heater, Converter SS | 5-10 Years | NOX 42CHL |
| 1 | 20-110 | PCB Power Supply | 5-10 Years | NOX 42CHL |
| 1 | 26335 | PC Board, Power Supply, PMT | 5-10 Years | NOX 42CHL |
| 1 | 20-058 | PMT, Tube | 5-10 Years | NOX 42CHL |
| 1 | 20-059 | Pmt, Base | 5-10 Years | NOX 42CHL |
| 1 | 26272 | Thermocouple Probe Assy | 5-10 Years | NOX 42CHL |
| 1 | 26337 | Thermister Assy | 5-10 Years | NOX 42CHL |
| 1 | 26277 | Pump,Vaccum KNF | 5-10 Years | NOX 42CHL |
| 1 | 26268 | Converter Molly (Optional) | 5-10 Years | NOX 42CHL |
| 1 | 20-072 | SS Converter | 5-10 Years | NOX 42CHL |

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## 9.0 COMMONLY USED EQUATIONS

**CEM Accuracy by Linearity Check (quarter audit):** Accuracy determined by linearity error check is specific to each analyzer or channel for the three audit gases injected (40 CFR 75, Appendix A).

$$\frac{|R-A|}{R} \times 100 = LE$$

or for alternate criteria use:

$$|R - A| = LE$$

| | | | |
|---|---|---|---|
| Where: | LE | = | Percent accuracy of the CEM |
| | R | = | Calibration gas reference value |
| | A | = | Average of monitor response |

**CEM Accuracy by RATA:** CEM accuracy determined using a RATA is specific to each pollutant measurement and is expressed in the units of the applicable emissions standard (40 CFR 60, Appendix B, PS-2).

$$100 \times \frac{d + cc}{RM} = RA$$

| | | | |
|---|---|---|---|
| Where: | RA | = | Percent relative accuracy |
| | d | = | Absolute value of the mean difference of the CEM response and the reference method results |
| | cc | = | Absolute value of the confidence coefficient |
| | RM | = | Average reference method measured emissions or applicable standard |

**Bias Adjustment:** The bias test is conducted using the RATA data and calculations. If the monitor fails to meet the bias test requirement, adjust the value obtained from the monitor using the following equations (40 CFR 75, Appendix A):

$$CEM_i^{ADJUSTED} = CEM_i^{MONITOR} \times BAF$$

Where: $CEM^{ADJUSTED}$ = Data value, adjusted for bias, at time i.
$CEM^{MONITOR}$ = Data (measurements) provided by the monitor at time i.
BAF = Bias adjustment factor, defined by

$$BAF = 1 + \frac{|\bar{d}|}{\overline{CEM}_{AVG}}$$

Where:

| | | |
|---|---|---|
| $\bar{d}$ | = | Arithmetic mean of the difference obtained during the failed bias test from the Arithmetic mean calculation of the relative accuracy test audit |
| $\overline{CEM}_{AVG}$ | = | Mean of the data values provided by the monitor during the failed bias test |

**Pollutant Analyzer Daily Calibration Error**

$S_d \geq$ Setpoint = Calibration Fail (Span)

$$S_d = \frac{S_r - S_b}{FS} \times 100$$

$Z_d \geq$ Setpoint - Calibration Fail (Zero)

$$Z_d = \frac{Z_r - Z_b}{FS} \times 100$$

| | | | |
|---|---|---|---|
| Where: | $S_d$ | = | Span drift, percent (upscale drift) |
| | $Z_d$ | = | Zero drift, percent |
| | $S_r$ | = | Span reading (upscale actual) |
| | $S_b$ | = | Span bottle value, (calibration variable) (upscale expected) |
| | FS | = | Analyzer fullscale value, ppm (for diluent, FS = 100) |
| | $Z_r$ | = | Zero reading (zero actual) |
| | $Z_b$ | = | Zero bottle (typical 0.0) (zero expected) |
| | Setpoint | = | 2 x PS (performance standard) for 1 day calibration fail |

**Diluent Analyzer Calibration Drift**

$S_d \geq$ Setpoint = Calibration Fail (Span)

$$S_d = S_r - S_b$$

Zd $\geq$ Setpoint - Calibration Fail (Zero)

$$Z_d = Z_r - Z_b$$

Where:

| | | |
|---|---|---|
| $S_d$ | = | Span drift, percent (upscale drift) |
| $Z_d$ | = | Zero drift, percent |
| $S_r$ | = | Span reading (upscale actual) |
| $S_b$ | = | Span bottle value, (calibration variable) (upscale expected) |
| $Z_r$ | = | Zero reading (zero actual) |
| $Z_b$ | = | Zero bottle (typical 0.0) (zero expected) |
| Setpoint | = | 2 x PS (performance standard) for 1 day calibration fail |

## 40 CFR 75, Appendix D Equations:

**$SO_2$ Mass Emissions Calculations for Oil:**
Use the following equation to calculate $SO_2$ Mass emissions per hour (Eq. D-2).

$$M_{SO2} = 2.0 \times M_{oil} \times \frac{\%S_{oil}}{100}$$

| | | | |
|---|---|---|---|
| Where: | $M_{SO2g}$ | = | Hourly mass of $SO_2$ emitted due to combustion of oil, lb/hr |
| | $M_{oil}$ | = | Mass of oil consumed per hour, lb/hr |
| | $\%S_{oil}$ | = | Percentage of sulfur by weight measured in sample |
| | 2.0 | = | Ratio of $SO_2$/lb S |

Where density of the oil is determined by the application of ASTM procedures use the following equation to calculate the mass of oil consumed in lb/hr (Eq. D-3).

$$M_{oil} = V_{oil} \times D_{oil}$$

| | | | |
|---|---|---|---|
| Where: | $M_{oil}$ | = | Mass of oil consumed, lb/hr |
| | $V_{oil}$ | = | Volume of oil consumed per hr, measured in scf, gal, barrel, or $m^3$ |
| | $D_{oil}$ | = | Density of oil, measured in lb/scf, lb/gal, lb/barrel, or lb/$m^3$ |

**$SO_2$ Mass Emissions Calculation for Gaseous Fuels:**
Use the following to calculate $SO_2$ emissions using gas sampling and analysis procedures described in 40 CRF 75, Appendix D, Section 2.3.1 (Eq. D-4).

$$M_{SO2g} = \frac{2.0}{7000} \times Q_g \times S_g$$

| | | | |
|---|---|---|---|
| Where: | $M_{SO2g}$ | = | Hourly mass of $SO_2$ emitted due to combustion of gaseous fuel, lb/hr |
| | $Q_g$ | = | Hourly metered flow or amount of gaseous fuel combusted, 100 scf/hr |
| | $S_g$ | = | Sulfur content of gaseous fuel, in grain/100 scf |
| | 2.0 | = | Ratio of $SO_2$/lb S |
| | 7000 | = | Conversion of grains/100 scf to lb/100 scf |

Use the following equation to calculate the $SO_2$ emissions using the default 0.0006 lb/MMBtu emission rate (Eq D-5):

$$M_{SO2g} = ER \times HI_g$$

| | | | |
|---|---|---|---|
| Where: | $M_{SO2g}$ | = | Hourly mass of $SO_2$ emitted due to combustion of pipeline natural gas, lb/hr |
| | ER | = | $SO_2$ default emission rate of 0.0006 lb/MMBtu for pipeline natural gas |
| | HIg | = | Hourly heat input of pipeline natural gas, calculated using procedures found in 40 CFR 75, Appendix F, in MMBtu/hr |

**Prorated Heat Input Calculation**

When both oil and gas are combusted within the same hour, a prorated heat input equation will be utilized (40 CFR 75, Appendix F, Equation D15).

$$HI_{rate\ hr} = \frac{\sum_{all\,fuels} HI_{rate\ i}\, t_i}{t_u}$$

Where:

| | | |
|---|---|---|
| $HI_{rate\text{-}hr}$ | = | Total heat input rate from all fuels combusted during the hour |
| $HI_{rate\text{-}i}$ | = | Heat input rate for each type of gas or oil combusted during the hour |
| $t_u$ | = | Operating time of the unit |
| $t_i$ | = | Time each gas or oil fuel was combusted for the hour (fuel usage time) (fraction of an hour) |

## 40 CFR 75, Appendix F Equations:

**Procedures for $NO_X$ Emission Rate**

When the $NO_X$ monitor uses $O_2$ as the diluent and measurements are on a dry basis, use the following (Eq. F-5):

$$E = K \times C_h \times F \frac{20.9}{20.9 - \%O2}$$

Where:

| | | |
|---|---|---|
| E | = | Pollutant emissions, lb/MMBtu |
| K | = | $1.194 \times 10^{-7}$ (lb/dscf)/ppm $NO_X$ |
| $C_h$ | = | Hourly average pollutant concentration, ppm dry |
| $\%O_2$ | = | Oxygen concentration, % volume |
| F | = | A factor representing a ratio of the volume of dry flue gases generated to the caloric value of the fuel combusted (F) – refer to F factor table |

Use the following equations to calculate F factors in lieu of the default F factors (Eq. F-7a and F-7b respectively):

$$F = \frac{3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)}{GCV} \times 10^6$$

Where H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent, as determined on the same basis as the gross calorific value (GCV) by ultimate analysis of the fuel combusted using ASTM D3176-89. F and $F_c$ factors are calculated at standard conditions of 68°F (20°C) and 29.92 inches Hg.

**Prorated F Factor Calculation**

When both oil and gas are combusted within the same hour, a prorated F factor equation will be utilized (40 CFR 75, Appendix F, Equation F-8).

$$F = \sum_{i=1}^{n} X_i F_i$$

Where:

| | | |
|---|---|---|
| $X_1$ | = | Fraction of total heat input derived from each type of fuel |
| $F_i$ | = | Applicable F factor for each type of fuel |
| n | = | Number of fuels being combusted in combination. |
| F | = | Prorated F factor |

**Procedures for $NO_X$ Mass Emissions**
40 CFR 75, Appendix F, equation F-24 will be utilized to calculate $NO_X$ mass emissions.

$$M_{(NOx)h} = E_{(NOx)h} \times HI_h \times t_h$$

Where:

| | | |
|---|---|---|
| $M_{(NOx)h}$ | = | $NO_X$ mass emissions in lbs for the hour |
| $E_{(NOx)h}$ | = | Hourly average $NO_X$ emission rate for hour h, lb/MMBtu (bias adjusted) |
| $HI_h$ | = | Hourly average heat input rate for hour h, MMBtu/hr |
| $t_h$ | = | Monitoring location operating time for hour h, in hours or fraction of an hour. |

**Procedures for Heat Input:**
For a unit that does not have a flow monitor and heat input is determined by fuel sampling use the following series of equations.

When the unit is combusting oil, use the following (Eq. F-19):

$$HI_o = M_o \times \frac{GCV_o}{10^6}$$

Where:

| | | |
|---|---|---|
| $HI_o$ | = | Hourly heat input from oil, MMBtu/hr |
| $M_o$ | = | Mass of oil consumed per hour, in lb, tons, or kg |
| $GCV_o$ | = | Gross calorific value of oil, as measured daily, Btu/unit mass |
| $10^6$ | = | Conversion of Btu to MMBtu |

When unit is combusting gaseous fuel, use the following (Eq. F-20):

$$HI_g = Q_g \times \frac{GCV_g}{10^6}$$

Where:

| | | |
|---|---|---|
| $HI_g$ | = | Hourly heat input from gaseous fuel, MMBtu/hr |
| $Q_g$ | = | Measured flow or amount of gaseous fuel combusted during the hour, hundred cubic feet |
| $GCV_o$ | = | Gross calorific value of gaseous fuel, as determined by sampling at least every month the gaseous fuel is combusted, or as verified by contractual supplier at least once every month the gaseous fuel is combusted |
| $10^6$ | = | Conversion factor, (Btu-100 scf/MMBtu-scf) |

## 40 CFR 75, Appendix G Equations:

Procedures for estimating $CO_2$ emissions from combustion. Use the following equation to calculate daily $CO_2$ mass emissions (in tons/day) from the combustion of fossil fuels (Eq. G-1):

$$W_{CO2} = \frac{(MW_c + MW_{O2}) \times W_c}{2{,}000 \times MW_c}$$

Where:

| | | |
|---|---|---|
| $W_{CO2}$ | = | $CO_2$ emitted from combustion, tons/day |
| $MW_c$ | = | Molecular weight of carbon (12.0) |
| $MW_{O2}$ | = | Molecular weight of oxygen (32.0) |
| $W_c$ | = | Carbon burned, lb/day, determined using fuel sampling and analysis and fuel feed rates |

In lieu of using the procedures, methods, and equations in Section 2.1 of 40 CFR 75, Appendix G, the owner/operator of an affected gas-fired unit may use the following equation and records of hourly heat input to estimate hourly $CO_2$ mass emissions, in tons (Eq. G-4):

$$W_{CO2} = \frac{F_c \times H \times U_f \times MW_{CO2}}{2000}$$

Where:

| | | |
|---|---|---|
| $W_{CO2}$ | = | $CO_2$ emitted from combustion, tons/day |
| $F_c$ | = | Carbon based F-factor |
| $H$ | = | Hourly heat input in MMBtu |
| $U_f$ | = | 1/385 scf $CO_2$/lb-mole at 14.7 psia and 69°F |
| $MW_{CO2}$ | = | Molecular weight of carbon (12.0) |

**F Factors for various fuels at standard conditions**
20°C (68°F) and 760 mm Hg (29.92 in. Hg)

| Type of fuel | $O_2$ Dry Basis ($F_d$) dscf/$10^6$ Btu | $O_2$ Wet Basis ($F_w$) dscf/$10^6$ Btu | $CO_2$ Basis ($F_c$) dscf/$10^6$ Btu |
|---|---|---|---|
| Coal | | | |
| Anthracite | 10100 | 10540 | 1970 |
| Bituminous | 9780 | 10640 | 1800 |
| Lignite | 9860 | 11950 | 1910 |
| Oil | 9190 | 10320 | 1420 |
| Gas | | | |
| Natural | 8710 | 10610 | 1040 |
| Propane | 8710 | 10200 | 1190 |
| Butane | 8710 | 10390 | 1250 |

# Attachment H
# Fuel Analysis

Fuel is specified as pipeline quality sweet natural gas and No. 2 fuel oil containing no more than 0.05 percent sulfur.

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FLORIDA GAS TRANSMISSION COMPANY
FERC Gas Tariff
Third Revised Volume No. 1

Third Revised Sheet No. 102C
Superseding
Second Revised Sheet No. 102C

GENERAL TERMS AND CONDITIONS
(continued)

am. GISB Definitions - shall mean any such definitions issued by GISB which have been adopted by the FERC. Transporter incorporates GISB Definitions (Version 1.3, July 31, 1998) 1.2.8 through 1.2.12 and 4.2.1 through 4.2.8 by reference herein.

2. QUALITY

A. Gas delivered by Shipper or for its account into Transporter's pipeline system at receipt points shall conform to the following quality standards:

1. shall be free from objectionable odors, solid matter, dust, gums, and gum forming constituents, or any other substance which might interfere with the merchantability of the gas stream, or cause interference with proper operation of the lines, meters, regulators, or other appliances through which it may flow;

2. shall contain not more than seven (7) pounds of water vapor per one thousand (1,000) MCF;

3. shall contain not more than one quarter (1/4) grain of hydrogen sulphide per one hundred (100) cubic feet of gas;

4. shall contain not more than ten (10) grains of total sulphur per one hundred (100) cubic feet of gas;

5. shall contain not more than a combined total three percent (3%) by volume of carbon dioxide and/or nitrogen;

6. shall contain not more than one quarter percent (1/4%) by volume of oxygen;

Issued by: Robert B. Kilmer, Vice President
Issued on: July 1, 1999

Effective: August 1, 1999

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# Attachment I
# Detailed Description of Control Equipment

The new simple cycle combustion turbine generator's pollution control equipment consists of dry low $NO_x$ burners and water injection to control emissions of $NO_x$ during natural gas and fuel oil firing respectively. A detailed description of the control equipment is summarized in the attached Technical Evaluation and Preliminary Determination document.

**JEA Brandy Branch Facility**
**PSD-FL-267 and 0310485-001-AC**
**Duval County, Florida**

## BACKGROUND

The applicant, JEA (formerly Jacksonville Electric Authority) proposes to install three nominal 170 megawatt (MW) General Electric PG 7241 FA combustion turbine-electrical generators at the planned Brandy Branch Facility near Baldwin City, Duval County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and $PM_{10}$), carbon monoxide (CO), nitrogen oxides ($NO_X$), sulfur dioxide ($SO_2$), and sulfuric acid mist (SAM). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The new units will operate in simple cycle mode and intermittent duty and exhaust through separate 90-foot stacks. JEA proposes to operate these units up to 4000 hours on natural gas and 800 hours on maximum 0.05 percent sulfur distillate fuel oil. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated August 11, 1999, accompanying the Department's Intent to Issue.

## DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on May 18, 1999 and included a proposed BACT proposal prepared by the applicant's consultant. Black & Veatch.

## REVIEW GROUP MEMBERS:

Michael P. Halpin, P.E. and A. A. Linero, P.E.

## BACT DETERMINATION REQUESTED BY THE APPLICANT:

| POLLUTANT | CONTROL TECHNOLOGY | PROPOSED BACT LIMIT |
|---|---|---|
| Nitrogen Oxides | Dry Low $NO_X$ Combustors<br>Water Injection (Oil) | 12 ppmvd @ 15% $O_2$ (gas)<br>42 ppmvd @ 15% $O_2$ (oil) |
| Particulate Matter | Pipeline Natural Gas<br>No. 2 Distillate Oil (800 hr/yr)<br>Combustion Controls | 10% Opacity |
| Carbon Monoxide | As Above | 15 ppm (gas, baseload)<br>20 ppm (oil baseload) |
| Sulfur Dioxide | As Above | 0.05% S in fuel oil |
| Sulfuric Acid Mist | As Above | 0.05% S in fuel oil |

According to the application, the maximum emissions from the facility will be approximately 858 tons per year (TPY) of $NO_X$, 366 TPY of CO, 75 TPY of $PM/PM_{10}$, 124 TPY of $SO_2$, 15 TPY of SAM, and 21 TPY of VOC.

## BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212.400, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

## STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd $NO_X$ @ 15% $O_2$ (assuming 25 percent efficiency) and 150 ppmvd $SO_2$ @ 15% $O_2$ (or <0.8% sulfur in fuel). The BACT proposed by JEA is within the NSPS limit, which allows $NO_X$ emissions, over 110 ppmvd for the high efficiency units to be purchased for the Brandy Branch Facility.

No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

## DETERMINATIONS BY EPA AND STATES:

The following table is based primarily on "F" Class intermittent-duty simple cycle turbines recently permitted or still under review. One project (PREPA) based on smaller units but permitted to operate continuously is included as an example of a simple cycle unit with add-on control equipment. Another continuous-duty project (Lakeland) based on the larger "G" Class is also included. The proposed JEA Brandy Branch project is included to facilitate comparison.

# APPENDIX BD
## BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

| Project Location | Power Output and Duty | $NO_X$ Limit ppmvd @ 15% $O_2$ and Fuel | Technology | Comments |
|---|---|---|---|---|
| Lakeland, FL | 250 MW SC CON | 9/9 – NG (by 2002)<br>42/15 - No. 2 FO | DLN/HSCR<br>WI/HSCR | 250 MW WH 501G CT<br>Initially 25 ppm $NO_X$ limit on gas<br>Issued 7/98. 250 hrs on oil. |
| Oleander Cocoa, FL | 850 MW SC INT | 9 - NG<br>42 - No. 2 FO | DLN<br>WI | 5x170 MW GE PG7241FA CTs<br>Draft 4/99. 1000 hrs on oil |
| **JEA Brandy, FL** | 510 MW SC INT | 12 - NG<br>42 - No. 2 FO | DLN<br>WI | 3x170 MW GE MS7241FA CTs<br>Application 5/99. 800 hrs on oil |
| JEA Kennedy, FL | 170 MW SC INT | 15 - NG<br>42 - No. 2 FO | DLN<br>WI | 170 MW GE MS7241FA CT<br>Issued 2/99. Not PSD/BACT |
| TEC Polk Power, FL | 330 MW SC INT | 10.5 – NG<br>42 – No. 2 F.O. | DLN<br>WI | 2x165 MW GE MS7241FA CTs<br>Application 2/99. 876 hrs on oil |
| Dynegy Heard, GA | 510 MW SC INT | 15 – NG | DLN | 3x170 MW WH 501F CTs<br>Application. Gas only |
| Tenaska Heard, GA | 960 MW SC INT | 15 - NG<br>42 - No. 2 FO | DLN<br>WI | 6x170 MW GE PG7241FA CTs<br>Issued 12/98. 720 hrs on oil |
| Thomaston, GA | 680 MW SC INT | 15 - NG<br>42 - No. 2 FO | DLN<br>WI | 4x170 MW GE PG7241FA CTs<br>Application. 1687 hrs on oil |
| Dynegy Reidsville, NC | 900 MW SC INT | 15 – NG (by 2002)<br>42 – No. 2 FO | DLN<br>WI | 5x180 MW WH 501F CTs<br>Initially 25 ppm $NO_X$ limit on gas<br>Draft 5/98. 1000 hrs on oil. |
| RockGen Cristiana, WI | 525 MW SC INT | 15/12 – NG<br>42 - No. 2 FO | DLN<br>WI | 3x175 MW GE PG7241FA CTs<br>15/12 ppm are on 1/24 hr basis<br>Issued 1/99. 800 hrs on oil |
| SEI Neenah, WI | 330 MW SC INT | 15/12 - NG<br>42 - No. 2 FO | DLN<br>WI | 2x165 MW GE PG7241FA CTs<br>15/12 ppm are on 1/24 hr basis<br>Issued 1/99. 8760/699 hrs gas/oil |
| PREPA, PR | 248 MW SC CON | 10 - No. 2 FO | WI & HSCR | 3x83 MW ABB GT11N CTs<br>Issued 12/95. |

CON = Continuous; SC = Simple Cycle; INT = Intermittent; DLN = Dry Low $NO_X$ Combustion; SCR = Selective Catalytic Reduction; HSCR = Hot SCR; FO = Fuel Oil; NG = Natural Gas; WI = Water or Steam Injection; GE = General Electric; WH = Westinghouse; ABB = Asea Brown Bovari

| Project Location | CO - ppm (or as indicated) | VOC - ppm (or as indicated) | PM - lb/hr (or as indicated) | Technology and Comments |
|---|---|---|---|---|
| Lakeland, FL | 25 - NG or 10 by Ox Cat<br>75 - FO @ 15% $O_2$ | 4 – NG<br>10 – FO | 10% Opacity | Clean Fuels<br>Good Combustion |
| Oleander Cocoa, FL | 12 - NG<br>20 - FO | 3 – NG<br>6 – FO | 10% Opacity | Clean Fuels<br>Good Combustion |
| **JEA Brandy, FL** | 15 - NG<br>20/26 (full/part load) - FO | 1.4 – NG<br>1.4 – FO | 9 lb/hr - NG<br>17 lb/hr - FO | Clean Fuels<br>Good Combustion |
| JEA Kennedy, FL | 15 - NG<br>20 - FO | 1.4 – NG<br>3.5 – FO | 9 lb/hr - NG<br>17 lb/hr - FO | Clean Fuels<br>Good Combustion |
| TEC Polk Power, FL | 15 - NG<br>33 - FO | 7 – NG<br>7 – FO | 10% Opacity | Clean Fuels<br>Good Combustion |
| Dynegy Heard Co., GA | 25 - NG | ? – NG | ? - NG | Clean Fuels<br>Good Combustion |
| Tenaska Heard Co., GA | 15 - NG<br>20 - FO | ? – NG<br>? – FO | ? - NG<br>? lb/hr - FO | Clean Fuels<br>Good Combustion |
| Dynegy Reidsville, NC | 25 - NG<br>50 - FO | 6 lb/hr – NG<br>8 lb/hr – FO | 6 lb/hr - NG<br>23 lb/hr - FO | Clean Fuels<br>Good Combustion |
| RockGen Cristiana, WI | 12@>50% load – NG<br>15@>75% 24@<75% - FO | 2 - NG<br>5 - FO | 18 lb/hr – NG<br>44 lb/hr - FO | Clean Fuels<br>Good Combustion |
| SEI Neenah, WI | 12@>50% load – NG<br>15@>75% 24@<75% - FO | 2 - NG<br>5 - FO | 18 lb/hr - NG<br>41 lb/hr - FO | Clean Fuels<br>Good Combustion |
| PREPA, PR | 9 – FO @15% $O_2$ | 11 – FO @15% $O_2$ | 0.0171 gr/dscf | Clean Fuels<br>Good Combustion |

## OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the information submitted by the applicant and that mentioned above, other information available to the Department consists of:

- Comments from EPA dated September 10, 1999
- Comments from the Fish and Wildlife Service dated July 20, August 12 and August 30, 1999
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - $NO_X$ Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for Jacksonville Electric Authority Brandy Branch Station Project
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combustion Turbine Startup Curves
- JEA Website – www.jea.com
- Goal Line Environmental Technologies Website – www.glet.com
- Catalytica Website – www.catalytica-inc.com

## REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for $NO_X$ Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

### Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal $NO_X$ forms in the high temperature area of the gas turbine combustor. Thermal $NO_X$ increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for $NO_X$ formation. Prompt $NO_X$ is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall $NO_X$ is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for $NO_X$ control by lean combustion.

Fuel $NO_X$ is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not a significant issue for the JEA project because these units will not be continuously operated, but rather will be "peakers". Also, low sulfur fuel oil (which has more fuel-bound nitrogen than natural gas) is proposed to be used for no more than 800 hours per year (per CT). Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% $O_2$). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% $O_2$ for each turbine of the JEA Project. The proposed $NO_X$ controls will reduce these emissions significantly.

### $NO_X$ Control Techniques

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal $NO_X$ formation. Typical emissions achieved by wet injection are in the range of 15–25 ppmvd when firing gas and 42 ppmvd when firing fuel oil in large combustion turbines. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection increase emissions of both of these pollutants.

Combustion Controls

The excess air in lean combustion cools the flame and reduces the rate of thermal $NO_X$ formation. Lean premixing of fuel and air prior to combustion can further reduce $NO_X$ emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is depicted in Figure 1 for a General Electric DLN-1 can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

To further reduce $NO_X$ emissions, GE developed the DLN-2.0 (cross section shown in Figure 1) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

GE has made further improvements in the DLN design. The most recent version is the DLN-2.6 (proposed for the JEA project). The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle. The emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 2 for a unit tuned to meet a 15 ppmvd $NO_X$ limit (by volume, dry corrected to at 15 percent oxygen) at Jacksonville Electric Authority's Kennedy Station.

$NO_X$ concentrations are higher in the exhaust at lower loads because the combustor does not operate in the lean pre-mix mode. Therefore such a combustor emits $NO_X$ at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.

The combustor can be tuned differently to achieve emissions as low as 9 ppm of $NO_X$ and 9 ppm of CO. Emissions characteristics while firing oil are expected to be similar for the DLN-2.6 as they are for those of the DLN-2.0 shown in Figure 3. Simplified cross sectional views of the totally premixed DLN-2.6 combustor to be installed at the JEA project are shown in Figure 4.

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal $NO_X$ formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, lowers achievable thermal efficiency for the unit.

Larger units, such as the Westinghouse 501 G or the planned General Electric 7H, use steam in a closed loop system to provide much of the cooling. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Instead it is normally sent back to a steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and $NO_X$ emissions can therefore be maintained at comparatively low levels even at high firing temperatures. At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

The relationship between flame temperature, firing temperature, unit efficiency, and $NO_X$ formation can be appreciated from Figure 5 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are as low as 9 ppmvd from gas turbines smaller than 200 MW (simple cycle), such as GE "F Class" units. Even lower $NO_X$ emissions are achieved from certain units smaller than 100 MW, such as the GE 7EA line.

Selective Catalytic Combustion

Selective catalytic reduction (SCR) is an add-on $NO_X$ control technology that is employed in the exhaust stream following the gas turbine. SCR reduces $NO_X$ emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with $NO_X$ in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1125 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Per the above table, only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. SCR is also proposed on a permanent basis for the expansion of the FPC Hines Facility (Power Block II). Seminole Electric will install SCR on a previously-permitted 501F unit at the Hardee Unit 3 project. The reasons are similar to those for the FPC Hines Power Block I.

Permit limits as low as 2.25 to 3.5 ppmvd $NO_X$ have been specified using SCR on combined cycle F Class projects throughout the country.

<u>Selective Non-Catalytic Combustion</u>

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100 °F is too low to support the $NO_X$ removal mechanism.

The Department did, however, specify SNCR as one of the available options for the combined cycle Santa Rosa Energy Center. The project will incorporate a large 600 MMBtu/hr duct burner in the heat recovery steam generator (HRSG) and can provide the acceptable temperatures (between 1400 and 2000 °F) and residence times to support the reactions.

<u>Emerging Technologies: SCONOX™ and XONON™</u>

There are at last two technologies on the horizon that will influence BACT determinations. These, as usual, are prompted by the needs specific to non-attainment areas such as Southern California.

The first technology is called $SCONO_X$™ and is a catalytic technology that achieves $NO_X$ control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires a dilute hydrogen reducing gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[1] California regulators and industry sources have stated that the first 250 MW block to install SCONOx ™ will be at U.S. Generating's La Paloma Plant near Bakersfield.[2] The overall project includes several more 250 MW blocks with SCR for control.[3] USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx™ system

SCONOx™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for $NO_X$ reduction. Advantages of the SCONOx ™ process include in addition to the reduction of $NO_X$, the elimination of ammonia and the control of some CO emissions. SCONOx™ has not been applied on any major sources in ozone attainment areas.

In a letter dated March 23, 1998 to Goal Line Environmental Technologies, the SCONOx™ process was deemed as technically feasible for maintaining $NO_x$ emissions at 2 ppmvd on a combined cycle unit. ABB Environmental was announced on September 10, 1998 as the exclusive licensee for SCONOx™ for United States turbine applications larger than 100 MW. ABB Power Generation has stated that scale up and engineering work will be required before SCONOx™ can be offered with commercial guarantees for large turbines (based upon letter from Kreminski/Broemmelsiek of ABB Power Generation to the Massachusetts Department of Environmental Protection dated November 4, 1998). SCONOx requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for this project. Therefore the SCONOx system cannot be considered as achievable or demonstrated in practice for this application.

The second technology is XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower $NO_X$ combustion) followed by flameless catalytic combustion to further attenuate $NO_X$ formation. The technology has been demonstrated on combustors on the same order of size as $SCONO_X$ ™ has. However GE has teamed with Catalytica to develop a combustor for gas turbines in the 80-90 MW range before continuing with development on a combustor for a larger unit. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

Catalytica Combustion Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. In a press release on October 8, 1998 Catalytica announced the first installation of a gas turbine equipped with the XONON™ Combustion System in a municipally owned utility for the production of electricity. The turbine was started up on that day at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, Calif. The XONON™ Combustion System, deployed for the first time in a commercial setting, is designed to enable turbines to produce environmentally sound power without the need for expensive cleanup solutions. Previously, this XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests which documented its ability to limit emissions of nitrogen oxides, a primary air pollutant, to less than 3 parts per million.

Catalytica's XONON™ system is represented as a powerful technology that essentially eliminates the formation of nitrogen oxides air emissions in gas turbines without impacting the turbine's operating performance. In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON™ systems for both new and installed GE E-class and F-class turbines used in power generation and mechanical drive applications. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. It is not yet available for fuel oil and cycling operation.

## REVIEW OF SULFUR DIOXIDE ($SO_2$) AND SULFURIC ACID MIST (SAM)

$SO_2$ control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for $SO_2$.

For this project, the applicant has proposed as BACT the use of 0.05% sulfur oil for up to 800 hours per CT as well as pipeline natural gas. The applicant estimated total emissions for the project at 124 TPY of $SO_2$ and 15 TPY of SAM. The Department expects the emissions to be lower because of the limited oil consumption and the typical natural gas in Florida that contains less than 1 grain of sulfur per 100 standard cubic feet (gr S/100ft$^3$). This value is well below the "default" maximum value of 20 gr. S/100 ft$^3$, but high enough to require a BACT determination.

## REVIEW OF PARTICULATE MATTER (PM/PM$_{10}$) CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the $NO_X$ controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM$_{10}$).

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and its use is proposed for only 800 hours per year making any conceivable add-on control technique for PM/PM$_{10}$ either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM$_{10}$ is a combination of good combustion practices, fuel quality, and filtration of inlet air. Total annual emissions of PM$_{10}$ for the project are expected to be approximately 75 tons per year.

## REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

All combustion turbines using catalytic oxidation appear to be combined cycle units. Among the most recently permitted ones are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppm. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Seminole Electric recently proposed catalytic oxidation in order to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[4]

Most combustion turbines incorporate good combustion to minimize emissions of CO. So far this appears to be the only technology proposed at simple cycle turbine projects. These installations typically achieve emissions between 10 and 25 ppm at full load while firing gas. The values of 15 and 20 ppm for gas and oil respectively at baseload proposed in JEA's original application are within the range of recent determinations for simple cycle CO BACT determinations. By comparison, values of 12 and 20 ppm for gas and oil respectively (at baseload) were proposed for the Oleander's project using identical equipment. Values given in GE-based applications are representative of operations between 50 and 100 percent of full load.

## REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques as the combustion turbine itself is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by JEA for this project are 1.4 ppm for both gas and oil firing at baseload. According to GE, however, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[5] By comparison, limits of 3 and 6 ppm were proposed for gas and oil firing respectively in the Oleander application. The limits proposed by JEA are sufficiently low to exempt the Brandy Branch project from BACT for VOC.

## BACKGROUND ON PROPOSED GAS TURBINE

JEA plans the purchase of three 170 MW (nominal) General Electric PG 7241FA simple cycle gas turbines. This is the most recent designation of GE's line of "F" Class units.

The first commercial GE 7F Class unit was installed in a combined cycle project at the Virginia Power Chesterfield Station in 1990.[6] The initial units had a firing temperature of 2300 °F and a combined cycle efficiency exceeding 50 percent. By the mid-90s, the line was improved by higher combustor pressure, a firing temperature of 2400 °F, and a combined cycle efficiency of approximately 56 percent based on a 167 MW combustion turbine. The line was redesignated as the 7FA Class.

The first GE 7F/FA project in Florida was at the FPL Martin Plant in 1993 and entered commercial service in 1994.[7] The units were equipped with DLN-2 combustors with a permitted $NO_X$ limit of 25 ppmvd. These actually achieved emissions of 13-25 ppmvd of $NO_X$, 0-3 ppm of CO, and 0-0.17 ppm of VOC.[8] The City of Tallahassee recently received approval to install a GE 7FA Class unit at its Purdom Plant.[9] Although permitted emissions are 12 ppmvd of $NO_X$, the City obtained a performance guarantee from GE of 9 ppmvd.[10] FPL also obtained a guarantee and permit limit of 9 ppmvd $NO_X$ for six GE 7241FA turbines to be installed at the Fort Myers Repowering project.[11] The Santa Rosa Energy Center in Pace, Florida, also received a permit with a 9 ppmvd $NO_X$ limit for a GE 7241 turbine with DLN-2.6 burners.[12]

Most recently, the Department issued draft BACT determinations for the simple cycle Oleander project in Brevard County and the combined cycle projects in Volusia (Duke Energy) and Osceola County (Kissimmee Utilities). These three draft permits also include $NO_X$ limits of 9 ppmvd based on the DLN-2.6 technology installed on F Class units.

General Electric has primarily relied on further advancement and refinement of DLN technology to provide sufficient $NO_X$ control for their combined cycle turbines in Florida. Where required by BACT determinations of certain states, General Electric incorporates SCR in combined cycle projects.[13] In its recent permits, Florida has included separate and lower limits in the event that DLN emissions limits are not attainable or the applicant selects a manufacturer that does not provide combustors capable of meeting 9 ppmvd.

GE's approach of progressively refining such technology is a proven one, even on some relatively large units. Recently GE Frame 7FA units met performance guarantees of 9 ppmvd with "DLN-2.6" burners at Fort St. Vrain, Colorado and Clark County, Washington.[14] Although the permitted limit is 15 ppmvd, GE has already achieved emission levels of approximately 6-7 ppmvd on gas at a dual-fuel 7EA (120 MW combined cycle) KUA Cane Island Unit 2.[15] Unit 2 is equipped with DLN-2 combustors. According to GE, similar performance is expected soon on the 7FA line such as the one that will be installed for the JEA Brandy Branch Project. Performance guarantees less than 9 ppmvd can be expected for DLN-2.6 combustors on units delivered in a couple of years.[16]

The 12 ppmvd $NO_X$ limit on natural gas proposed by JEA is a fairly stringent BACT determination for simple cycle F Class, though it is becoming less so. The company has obtained a guarantee from GE to achieve 9 ppmvd, which is for a performance test on a "new and clean unit." The test must be conducted at a steady-state load of 50 to 100 percent and completed within the first 100 fired hours of operation as specified in the GE protocols.

With the frequent start-ups and shutdowns of the unit, JEA is concerned about the ability to maintain the low (9 ppmvd) $NO_X$ values for long periods of time following the performance tests. Presumably, this concern would be lessened should these units be converted to a more continuous duty (i.e combined cycle). Although the Department is not fully aware of the details of the GE guarantee for Oleander (proposed 9 ppmvd on a simple cycle unit), the Department is aware from discussions with other applicants that a continuing guarantee is available at a substantial cost.[17]

The GE Speedtronic™ Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. Since emissions are controlled utilizing dry low $NO_X$ techniques, fuel staging and combustion mode are also controlled by the Mark V, which also monitors the process. Sequencing of the auxiliaries to allow fully automated start-up, shutdown and cool-down are also handled by the Mark V.[18]

## DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the JEA project assuming full load. Values for $NO_X$ are corrected to 15% $O_2$ on a dry volume basis. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions No. 20 through 25.

| POLLUTANT | CONTROL TECHNOLOGY | PROPOSED BACT LIMIT |
|---|---|---|
| $PM/PM_{10}$ | Pipeline Natural Gas<br>Good Combustion | 10 Percent Opacity<br>9 lb/hr – Gas<br>17 lb/hr – Fuel Oil |
| CO | As Above | 12* ppm – Gas<br>20 ppm – Fuel Oil |
| $SO_2$/SAM | As Above | 2 grains of sulfur per 100 $ft^3$ gas<br>0.05 percent sulfur in fuel oil |
| $NO_X$ | Dry Low $NO_X$, WI for F.O., limited oil use | 10.5 ppmvd – Gas<br>42* ppmvd – F.O. for 750 of 4750hours |

* See discussion below.

## RATIONALE FOR DEPARTMENT'S DETERMINATION

- JEA has agreed to shutdown its Southside facility, also located in Duval County. This will result in a net decrease of regulated pollutants which are emitted.
- General Electric has provided a "clean and new" one-time guarantee of 9 ppmvd $NO_X$.
- Typical "continuous" permit limits nation-wide for these GE 7FA units while operating on natural gas and in simple cycle mode and intermittent duty are 12-15 ppmvd even though GE provides the same "new and clean" guarantees for them. Limits as high as 25 ppmvd have been recently proposed by some for similar units produced by other manufacturers.
- A level of 9 ppmvd $NO_X$ by DLN has been demonstrated on GE 7FA combustion turbines at Fort St. Vrain, Colorado and Clark County, Washington. However the permitted limits are actually higher at these two facilities providing some level of operating margin.
- A limit of 9 ppmvd was <u>proposed</u> by Oleander for five GE7 FA units and is reflected in the Department's recent Draft BACT Determination for that facility. A BACT level of 9 ppmvd has been proposed by Virginia Power for a GE 7FA unit to avoid non-attainment New Source Review.
- The proposed 9 ppmvd limit at Oleander and Virginia Power while firing natural gas is the lowest known <u>Draft</u> BACT value for an "F" frame combustion turbine operating in simple cycle mode and intermittent duty. The 42 ppmvd limit while firing fuel oil is typical.
- The Department prepared a Draft permit for the TEC Polk Power Station Project adopting TEC's proposed 10.5 ppmvd limit for two GE 7FA units, but limited the hours of operation on fuel to less than the hours allowed at Oleander. The TEC Draft BACT is being issued concurrently with the Draft BACT for the JEA project.
- JEA's <u>proposed</u> 12 ppmvd limit for the Brandy Branch Facility while firing natural gas is relatively low for a GE 7FA Class simple cycle, intermittent duty unit.
- The <u>Department</u> however, proposes a BACT limit of 10.5 ppmvd, which is the same as proposed for the TEC project. The Department also proposes to limit oil firing to the same number of hours as TEC (750) and less than the number of hours at Oleander (1000). Considering the applicant's shutdown of its Southside facility in conjunction with the Department's BACT limits, net annual $NO_X$ emissions (TPY) will be approximately zero.
- The Department will still require JEA to meet to meet the "clean and new" limit of 9 ppmvd during initial testing as well as requiring a continuous 9 ppmvd guarantee (or better) in the event that JEA converts the units to continuous duty (i.e. combined cycle).
- The proposed BACT limit of 10.5 ppmvd is about one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- The units will be operated in simple cycle mode. Therefore control options, which are feasible for combined cycle units, are not applicable. This rules out Low Temperature (conventional) SCR, which achieves 4.5 ppmvd $NO_X$ or lower. It also rules out the possibility of SCONOx. XONON is not available for F Class dual fuel projects.
- The simple cycle "F Class" turbines have very high exhaust temperatures of up to 1200 °F. Without additional cooling, this is at the higher limit of the present operational temperature of

- Hot SCR zeolite catalyst (around 1125 °F). The PREPA simple cycle turbines, which use Hot SCR, have exhaust temperatures ranging from 824 to 1024°F and burn exclusively #2 oil.

- The levelized costs of $NO_X$ removal by Hot SCR for the JEA project were estimated by Black & Veatch at $13,380 per ton assuming 4000 hours of operation on natural gas and a reduction from 12 to 5 ppmvd. The Department estimates that this figure is reduced by including oil operation (up to 750 hours per year) and other criteria, but still exceeds $7,000 per ton.

- TEC estimated the cost of Hot SCR at $9,717 per ton of $NO_X$ removed assuming 4,380 and 876 hours per year of operation on gas and oil respectively.

- The Department previously concluded that Hot SCR is cost-effective for continuous duty simple cycle service (Lakeland). EPA also concluded Hot SCR is cost-effective on continuous duty simple cycle projects (PREPA).

- Although the Department does not have a "bright line" cost-effectiveness figure and does not necessarily adopt the precise cost calculations for the JEA and TEC projects, the values projected by JEA and TEC indicate that Hot SCR is not cost-effective for their respective projects.

- Comments from the National Park Service on the Oleander project suggested that a reduction in the applicant's proposed $NO_X$ emissions on oil from 42 ppmvd to 25 ppmvd is possible based on reported oil-fired units listed in the BACT Clearinghouse. GE has advised that it only offers a 42 ppmvd $NO_X$ guarantee on F Class units when firing oil.

- The Department is aware that ABB offers a DLN technology for fuel oil firing applicable to at least certain smaller combustion turbines (ABB-GTX). It is noted, however that ABB does not offer a guarantee of 9 ppmvd on the same unit when firing natural gas.

- It is possible that the $NO_X$ emissions while firing oil from may be reduced from 42*ppmvd by increasing the water injection rate. In order to address this possibility, a specific condition will be added to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department's review to ensure that the lowest reliable $NO_X$ emission rates while firing oil have been achieved.

- The Department's overall BACT determination is equivalent to approximately 0.5 lb./MW-hr $NO_X$ emissions for combined gas and oil operation. For reference, the new NSPS promulgated on September 3, 1998 requires that new conventional power plants (based on boilers, etc.) meet a limit of 1.6 lb/MW-hr. FDEP BACT analyses typically target values less than 1.0 lb./MW-hr for simple cycle CT's and less than 0.5 lb./MW-hr for combined cycle units.

- VOC emissions of 1.4 ppm while firing gas or oil proposed by the applicant clearly reflect BACT and, in fact, exempt the project from a BACT determination for VOC. The Department will set VOC limits at 2 ppm (gas) and 3.5 ppm (oil). These values are still sufficient to maintain VOC emissions to less than 40 tons per year.

- The Department will set CO limits achievable by good combustion at full load as 12* ppm (gas) and 20 ppm (oil). These values are equal to the lowest values from permitted or proposed simple cycle units and are equal to those proposed by the Department for Oleander and TEC project. Due to the applicant's (higher) guarantee while firing gas of 15 ppm, the specific permit condition will be worded so as to allow for initial 15 ppm operation with a requirement

- to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department's review to ensure that the lowest reliable CO emission rates while firing gas have been achieved.

- Black & Veatch evaluated the use of an oxidation catalyst for the JEA project with an 88 percent control efficiency and having a three-year catalyst life. The oxidation catalyst control system was estimated to increase the capital cost of the project by $1,905,000 with an annualized cost of $509,000 per year. Levelized costs for CO catalyst control were calculated at $4,700 per ton. This figure does not appear to be cost-effective for removal of CO.

- BACT for $PM_{10}$ was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; use of clean, low ash, low sulfur fuels for limited hours, and operation of the unit in accordance with the manufacturer-provided manuals.

- $PM_{10}$ emissions will be very low and difficult to measure. Additionally, the higher emission mode will involve fuel oil firing which will occur only approximately 750 hours per year. It is not practical to require running the turbine on oil, simply to conduct tests. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, the City of Tallahassee, Santa Rosa Energy Center, FPL Fort Myers, and the Southern Company Barry projects.

**Compliance Procedures**

| POLLUTANT | COMPLIANCE PROCEDURE |
|---|---|
| Particulate Matter | Method 9 |
| Carbon Monoxide | Annual Method 10 (can use RATA if at capacity) |
| $NO_X$ (performance) | Annual Method 20 (can use RATA if at capacity) |
| $NO_X$ (24-hr block average) | $NO_X$ CEMS, $O_2$ or $CO_2$ diluent monitor, and flow device as needed |
| $SO_2$ and SAM | Custom Fuel Monitoring Schedule |

**DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:**

Michael P. Halpin, P.E., Review Engineer, New Source Review Section MPHalpin PE
A. A. Linero, P.E. Administrator, New Source Review Section AA Linero PE
Department of Environmental Protection / Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

CH Fancy

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

10/13/99
Date:

Approved By:

CH Fancy

for Howard L. Rhodes, Director
Division of Air Resources Management

10/13/99
Date:

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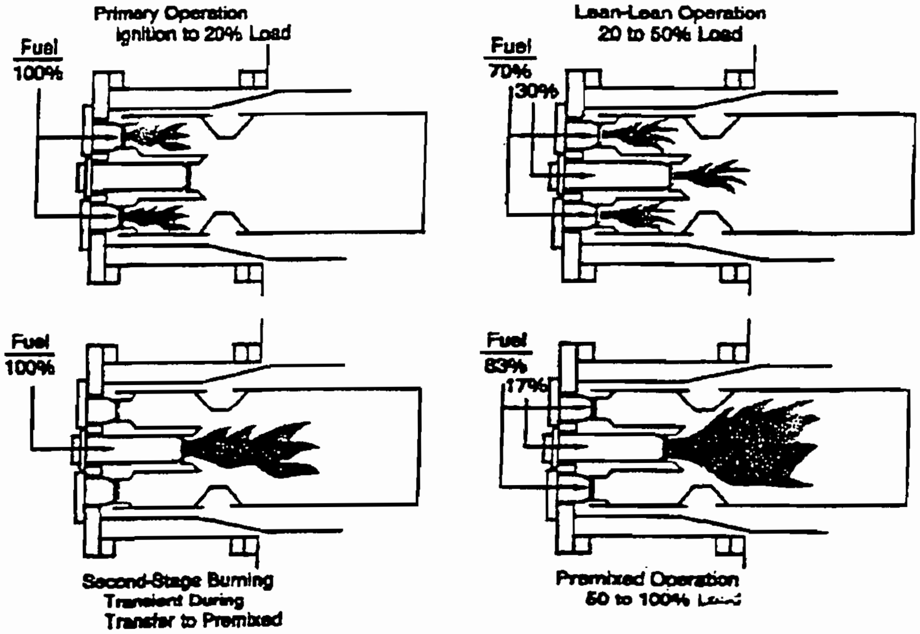


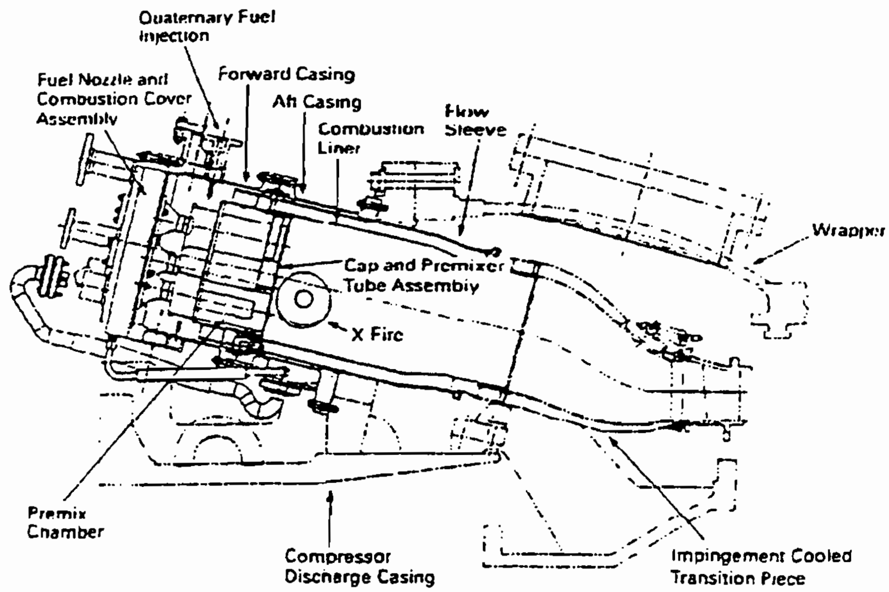


Figure 1 - Dry Low NOx Operating Modes - DLN-1

Cross Section of GE DLN-2

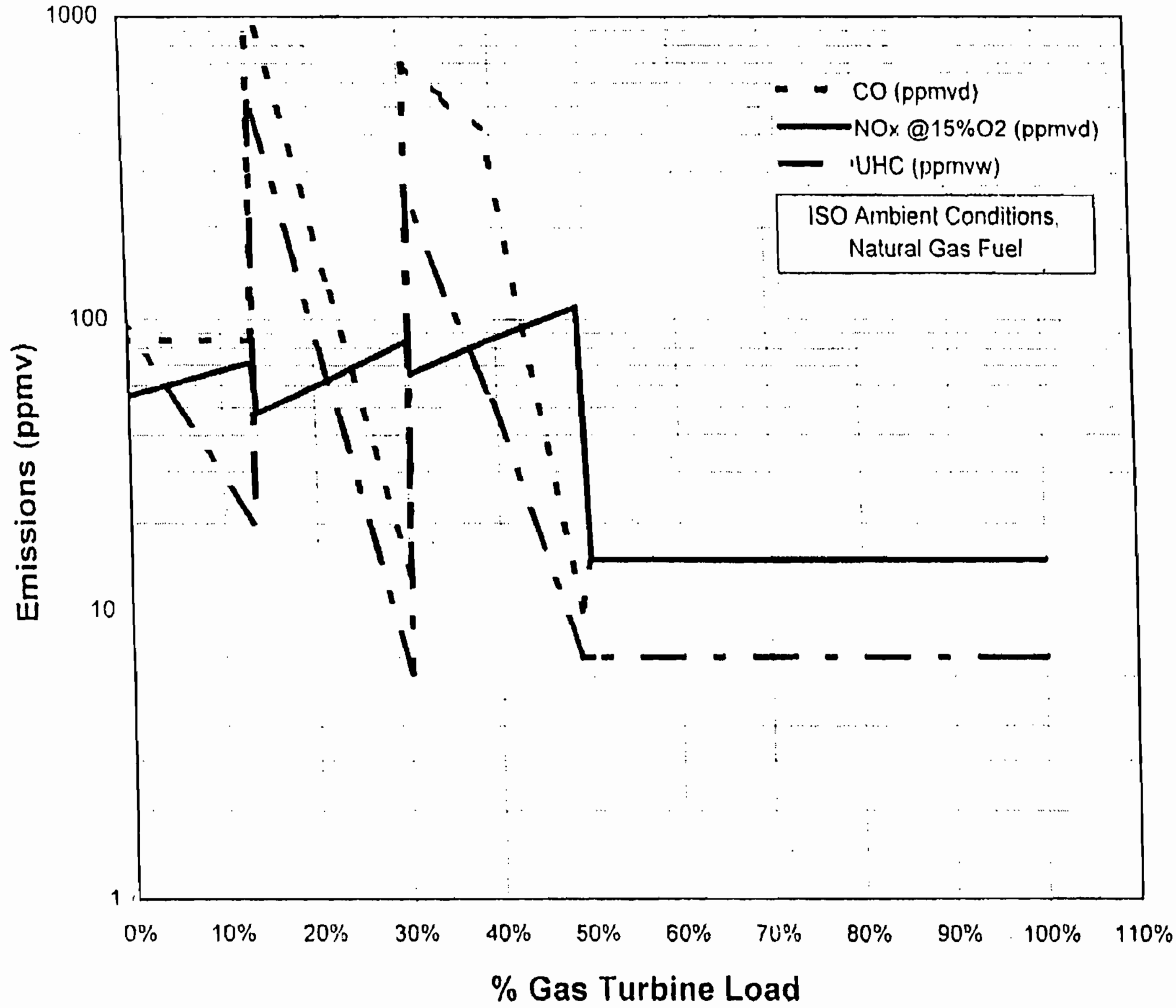


Figure 2 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

(Simple Cycle Intermittent Duty – If Tuned to 15 ppmvd $NO_X$)

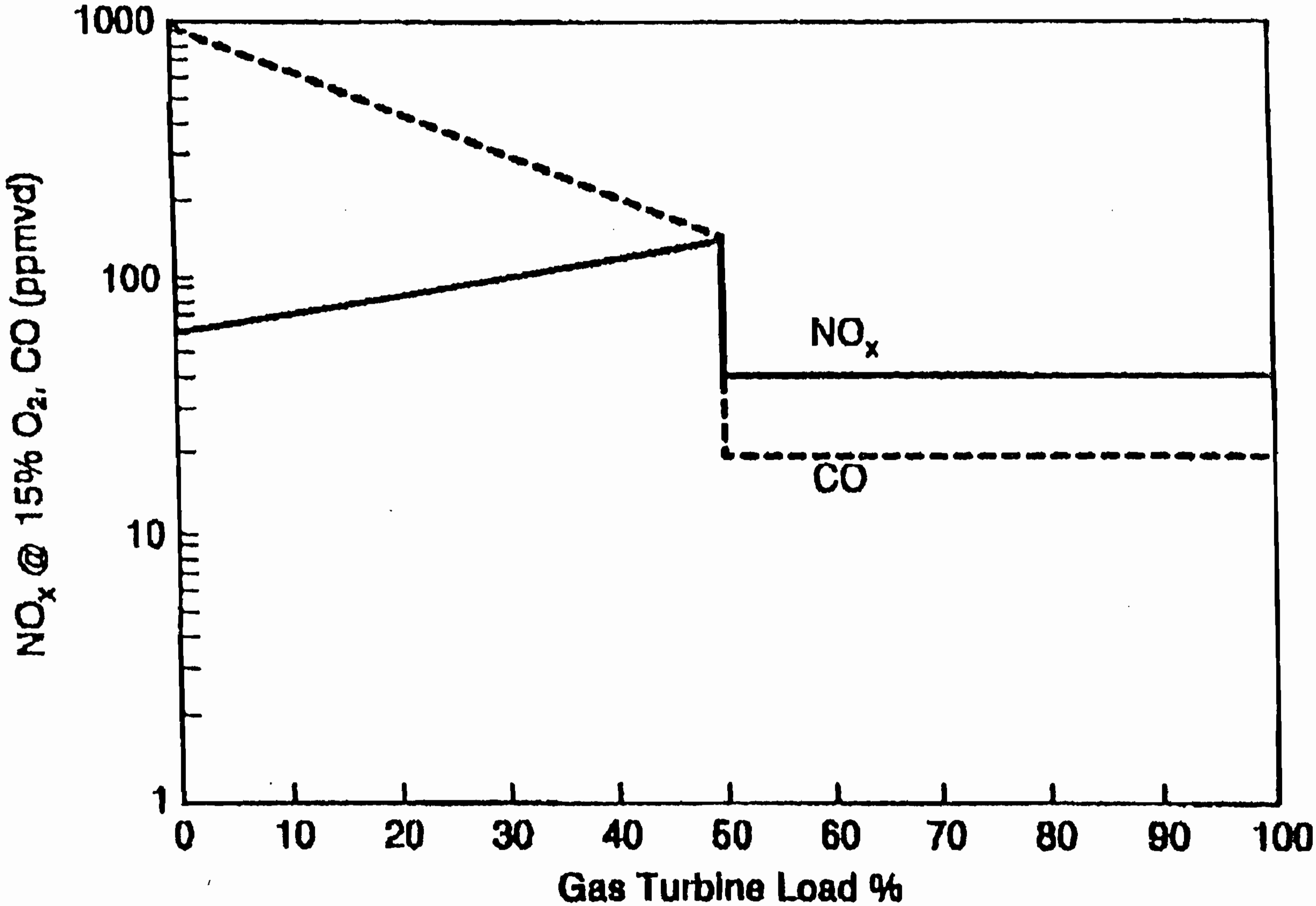


Figure 3 – Emissions Performance for DLN-2 Combustors Firing Fuel Oil in Dual Fuel GE 7FA Turbine

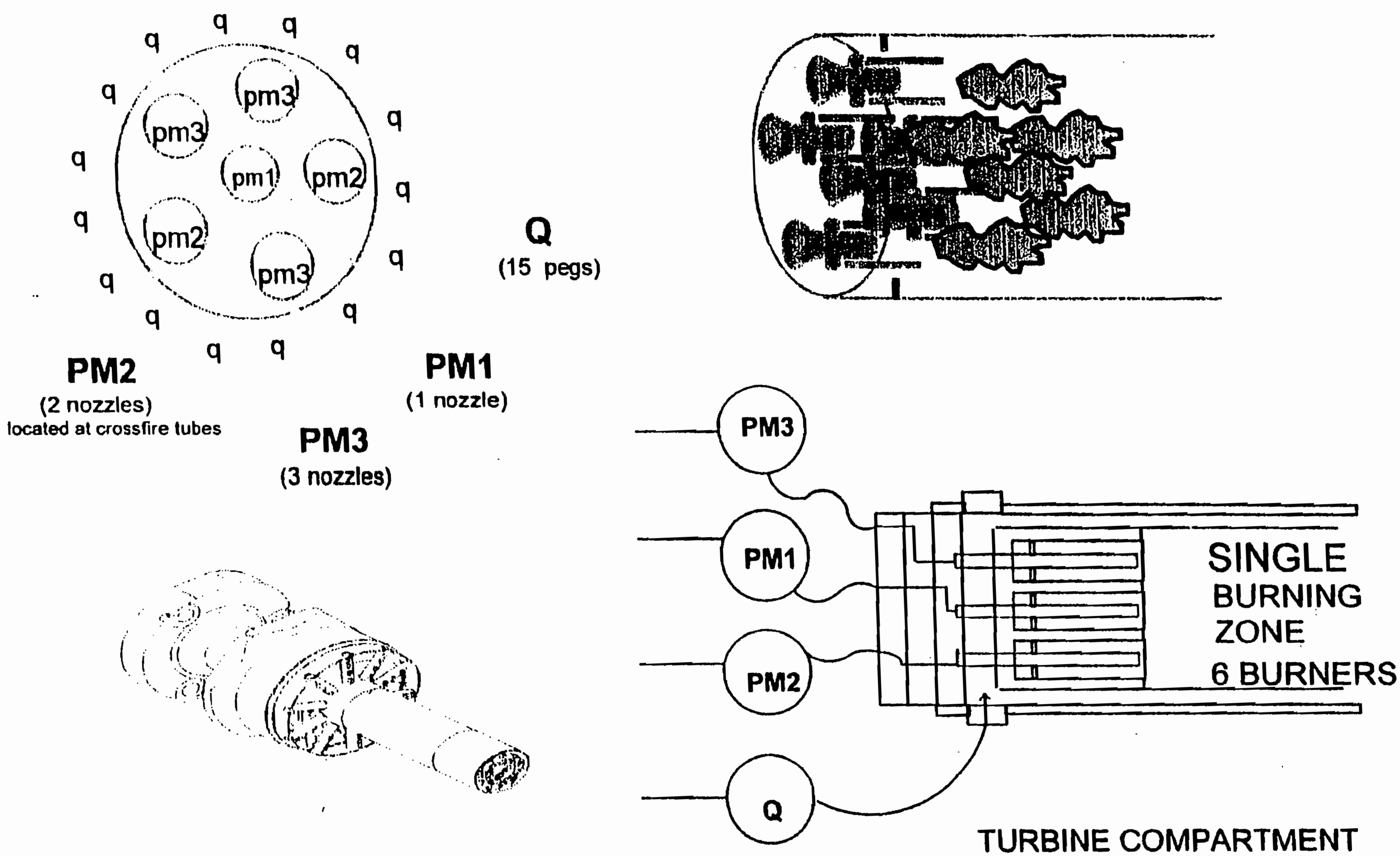


Figure 4 - DLN-2.6 Nozzle and Burner Arrangement

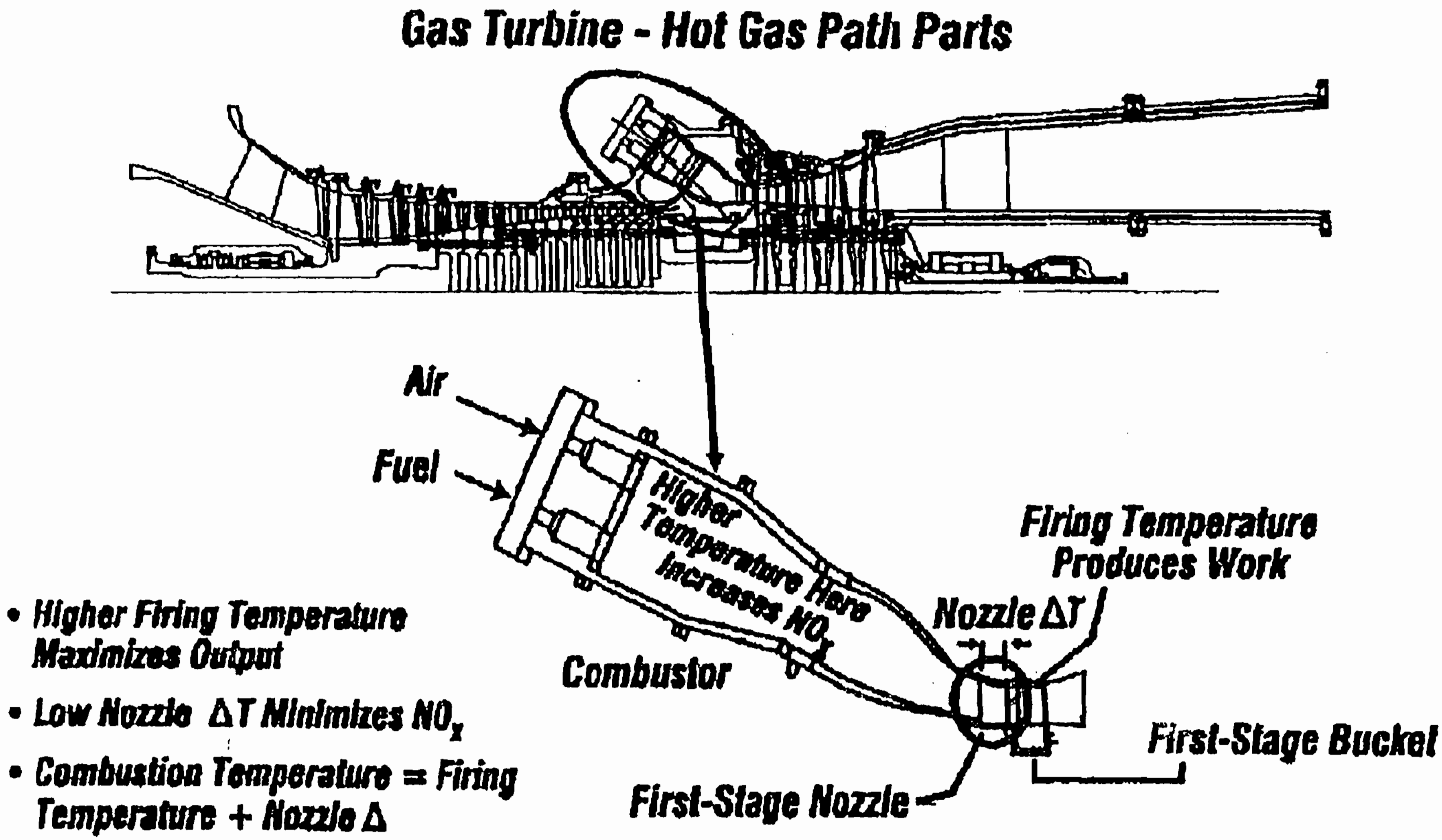


Figure 5 - Relation Between Flame Temperature and Firing Temperature

# Attachment J
# Description of Stack Sampling Facilities

The stack sampling facilities were installed in accordance with Rule 62-297.310(6) (attached), as required by Air Construction Permit No. 0310485-004-AC.

A description of the sampling ports follows:

T
S
I

## Air Report - Sampling Point Locations

| | |
|---|---|
| **Facility** | **JEA** |
| **Location** | **Baldwin, FL.** |
| **Source Name** | **CT-2 Turbine** |

**Stack Interior Diameter = 216.00 inches**

| Sample Point Number | Inches Inside Stack Wall |
|---|---|
| 1 | 4.54 |
| 2 | 14.47 |
| 3 | 25.49 |
| 4 | 38.23 |
| 5 | 54.00 |
| 6 | 76.90 |

**4 Ports**

**Distances From Nearest Disturbance**

| Source | Stack Distance |
|---|---|
| Downstream - - - - - - - - - - - - - - - - - - - - - | < 7 diameters |
| Upstream - - - - - - - - - - - - - - - - - - - - - | < 7 diameters |

**The above mentioned Downstream and Upstream distances are approximate distances.**

(5) Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

(6) Required Stack Sampling Facilities. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

(a) Permanent Test Facilities. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

(b) Temporary Test Facilities. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

(c) Sampling Ports.

1. All sampling ports shall have a minimum inside diameter of 3 inches.

2. The ports shall be capable of being sealed when not in use.

3. The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

4. For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

5. On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

(d). Work Platforms.

1. Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

2. On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

3. On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

4. All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toeboard, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

(e). Access to Work Platform.

1 Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

2. Walkways over free-fall areas shall be equipped with safety rails and toeboards.

(f). Electrical Power.

1. A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

2. If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

(g). Sampling Equipment Support.

1. A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

a. The bracket shall be a standard 3 inch x 3 inch x one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

b. A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

c. The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

2. A complete monorail or dualrail arrangement may be substituted for the eyebolt and bracket.

3. When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

(7) Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 -- September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a. Visible emissions, if there is an applicable standard;

b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

c. Each NESHAP pollutant, if there is an applicable emission standard.

# Attachment K
# Compliance Test Report

Units' 1 and 2 initial emission stack tests have been completed and the results submitted to the Jacksonville Regulatory and Environmental Services Department (RESD) and DEP's Northeast District Offices. A summary of results is provided in the following tables.

## USE OF THIS REPORT AND INFORMATION INCLUDED

This Report and the information contained is the property of the individual or organization named on the face hereof and may be freely distributed in its present form.

## REPORT CERTIFICATION

Technical Services, Inc. (TSI) has used its professional experience and best professional efforts in performing this compliance test. I have reviewed the results of these tests and to the best of my knowledge and belief they are true and correct.

**REPORT NO.** 0106A05

Harvey C. Gray, Jr.

HARVEY C. GRAY, JR.

DATE:

## Executive Summary

On June 14 and 15, 2001 Technical Services Incorporated (TSI) conducted air emission testing on Jacksonville Electric Authority's (JEA) combustion turbine number BCT-1 located at the Brandy Branch Power Park. This test was performed in order to satisfy specific requirements as specified in the State of Florida issued air construction permit number PSD-FL-267 (0310485-001-AC). The following table presents a summary of the test results. All of the test results indicate compliance with the permit requirements.

| Parameter | Test Method | Permitted Limit | Test Results | Compliance Status |
|---|---|---|---|---|
| Oxides of Nitrogen (NOx) | USEPA Method 20 | 10.5 ppm @ 15% oxygen | 7.1 ppm @ 15% oxygen | Pass |
| Carbon Monoxide (CO) | USEPA Method 10 | 15 ppm | 1 ppm | Pass |
| Volatile Organic Compounds (VOC) | USEPA Method 25a | 2 ppm | 0 ppm | Pass |
| Visible Emissions | USEPA Method 9 | 10 % opacity | 0 % opacity | Pass |
| Flow | USEPA Method 1,2,3,3a, and 4 | N/A | 761771 scfm-dry<br>838163 scfm-wet | N/A |
| Oxygen | USEPA Method 3a | N/A | 13.8 % | N/A |

Executive Summary

On June 18, 2001 Technical Services Incorporated (TSI) conducted air emission testing on Jacksonville Electric Authority's (JEA) combustion turbine number BCT-2 located at the Brandy Branch Power Park. This test was performed in order to satisfy specific requirements as specified in the State of Florida issued air construction permit number PSD-FL-267 (0310485-001-AC). The following table presents a summary of the test results. All of the test results indicate compliance with the permit requirements. This test was conducted with the turbine operating at **BASE LOAD** fired with **NATURAL GAS**.

| Parameter | Test Method | Permitted Limit | Test Results | Compliance Status |
|---|---|---|---|---|
| Oxides of Nitrogen (NOx) | USEPA Method 20 | 10.5 ppm @ 15% oxygen | 6.8 ppm @ 15% oxygen | Pass |
| Carbon Monoxide (CO) | USEPA Method 10 | 15 ppm | 1 ppm | Pass |
| Volatile Organic Compounds (VOC) | USEPA Method 25a | 2 ppm | 0 ppm | Pass |
| Visible Emissions | USEPA Method 9 | 10 % opacity | 0 % opacity | Pass |
| Flow | USEPA Method 1,2,3,3a, and 4 | N/A | 821920 scfm-dry 903210 scfm-wet | N/A |
| Oxygen | USEPA Method 3a | N/A | 13.8 % | N/A |

Executive Summary

On June 22, 2001 Technical Services Incorporated (TSI) conducted air emission testing on Jacksonville Electric Authority's (JEA) combustion turbine number BCT-2 located at the Brandy Branch Power Park. This test was performed in order to satisfy specific requirements as specified in the State of Florida issued air construction permit number PSD-FL-267 (0310485-001-AC). The following table presents a summary of the test results. All of the test results indicate compliance with the permit requirements. This test was conducted with the turbine operating at **BASE LOAD** fired with **OIL.**

| Parameter | Test Method | Permitted Limit | Test Results | Compliance Status |
|---|---|---|---|---|
| Oxides of Nitrogen (NOx) | USEPA Method 20 | 42 ppm @ 15% oxygen | 31 ppm @ 15% oxygen | Pass |
| Carbon Monoxide (CO) | USEPA Method 10 | 20 ppm | <1 ppm | Pass |
| Volatile Organic Compounds (VOC) | USEPA Method 25a | 3.5 ppm | <1 ppm | Pass |
| Visible Emissions | USEPA Method 9 | 10 % opacity | 0 % opacity | Pass |
| Flow | USEPA Method 1,2,3,3a, and 4 | N/A | 711902 scfm-dry<br>805319 scfm-wet | N/A |
| Oxygen | USEPA Method 3a | N/A | 12.5 % | N/A |

# Attachment L
# Procedures for Startup and Shutdown

Procedures for startup and shutdown will be completed in accordance with the manufactures' operating procedures. Excess emissions resulting from startup and shutdown are permitted in condition 26 of the permit (No. 0310485-004-AC).

# Attachment M
# Alternative Methods of Operation

Alternative methods of operation include the use of pipeline quality natural gas and 0.05 percent sulfur NO. 2 or superior grade of fuel oil.

# Attachment N
# Acid Rain Application

Environmental Protection Agency
Acid Rain Program

OMB No. 2060-02

EPA

# Certificate of Representation

Page

For more information, see instructions and refer to 40 CFR 72.24

This submission is: ☐ New ☒ Revised (revised submissions must be completed in full; see instructions)

This submission includes combustion or process sources under 40 CFR part 74 ☐

**STEP 1**
**Identify the source by plant name, State, and ORIS code.**

| | | |
|---|---|---|
| Plant Name Brandy Branch | State FL | ORIS Code 7846 |

**STEP 2**
**Enter requested information for the designated representative.**

| | |
|---|---|
| Name Jon P. Eckenbach, Executive Vice President | |
| Address 21 West Church Street<br>Jacksonville, FL 32202 | |
| Phone Number (904) 665-6315 | Fax Number (904) 665-7366 |
| E-mail address (if available) eckejp@jea.com | |

**STEP 3**
**Enter requested information for the alternate designated representative, if applicable.**

| | |
|---|---|
| Name Susan Hughes, Vice President | |
| Phone Number (904) 665-6248 | Fax Number (904) 665-7376 |
| E-mail address (if available) hughsn@jea.com | |

**STEP 4**
**Complete Step 5, read the certifications, and sign and date. For a designated representative of a combustion or process source under 40 CFR part 74, the references in the certifications to "affected unit" or "affected units" also apply to the combustion or process source under 40 CFR part 74 and the references to "affected source" also apply to the source at which the combustion or process source is located.**

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the affected source and each affected unit at the source.

I certify that I have given notice of the agreement, selecting me as the 'designated representative' for the affected source and each affected unit at the source identified in this certificate of representation, in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice.

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and of each affected unit at the source and that each such owner and operator shall be fully bound by my actions, inactions, or submissions.

I certify that I shall abide by any fiduciary responsibilities imposed by the agreement by which I was selected as designated representative or alternate designated representative, as applicable.

I certify that the owners and operators of the affected source and of each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under life-of-the-unit, firm power contractual arrangements, I certify that:

> I have given a written notice of my selection as the designated representative or alternate designated representative, as applicable, and of the agreement by which I was selected to each owner and operator of the affected source and of each affected unit at the source; and
>
> Allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement or, if such multiple holders have expressly provided for a different distribution of allowances by contract, that allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

The agreement by which I was selected as the alternate designated representative, if applicable, includes a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative.

| |
|---|
| Plant Name (from Step 1) Brandy Branch |



I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

| | |
|---|---|
| Signature (designated representative) | Date 11/14/00 |
| Signature (alternate designated representative) | Date 11/17/00 |

**STEP 5**
**Provide the name of every owner and operator of the source and identify each affected unit (or combustion or process source) they own and/or operate.**

| | | | | | | |
|---|---|---|---|---|---|---|
| Name JEA | | | | | ☒ Owner | ☒ Operator |
| ID# 1 | ID# 2 | ID# 3 | ID# | ID# | ID# | ID# |
| ID# | ID# | ID# | ID# | ID# | ID# | ID# |

| | | | | | | |
|---|---|---|---|---|---|---|
| Name | | | | | ☐ Owner | ☐ Operator |
| ID# | ID# | ID# | ID# | ID# | ID# | ID# |
| ID# | ID# | ID# | ID# | ID# | ID# | ID# |

| | | | | | | |
|---|---|---|---|---|---|---|
| Name | | | | | ☐ Owner | ☐ Operator |
| ID# | ID# | ID# | ID# | ID# | ID# | ID# |
| ID# | ID# | ID# | ID# | ID# | ID# | ID# |

| | | | | | | |
|---|---|---|---|---|---|---|
| Name | | | | | ☐ Owner | ☐ Operator |
| ID# | ID# | ID# | ID# | ID# | ID# | ID# |
| ID# | ID# | ID# | ID# | ID# | ID# | ID# |

JEA

December 30, 1999

Mr. Scott Sheplak, P.E.
Title V Administrator
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Brandy Branch Facility
Acid Rain Application Forms

Dear Mr. Sheplak:

Enclosed please find the Acid Rain Application Forms for the Brandy Branch Facility.

If you have any questions with regard to this matter, please contact me at (904) 665-6247.

Sincerely,

N. Bert Gianazza, P.E.
Environmental Permitting
& Compliance Group

cc: USEPA
USEPA, Region 4

bc: J. Connolly
E. Mims
L. Starner
B. Gianazza
File

bbacidrain

# Phase II Permit Application

Page 1

For more information, see instructions and refer to 40 CFR 72.30 and 72.31 and Chapter 62-214, F.A.C.

This submission is: ☒ New ☐ Revised

STEP 1
Identify the source by plant name, State, and ORIS code from NADB

Plant Name Brandy Branch State FL ORIS Code 7846

STEP 2 Enter the boiler ID# from NADB for each affected unit and indicate whether a repowering plan is being submitted for the unit by entering "yes" or "no" at column c. For new units, enter the requested information in columns d and e.

| a | b | c | d | e |
|---|---|---|---|---|
| | Compliance Plan | | | |
| Boiler ID# | Unit will hold allowances in accordance with 40 CFR 72.9(c)(1) | Repowering Plan | New Units<br>Commence Operation Date | New Units<br>Monitor Certification Deadline |
| 001 | Yes | | Dec. 2000 | Dec. 2000 |
| 002 | Yes | | Dec. 2000 | Dec. 2000 |
| 003 | Yes | | Dec. 2001 | Dec. 2001 |
| | Yes | | | |
| | Yes | | | |
| | Yes | | | |
| | Yes | | | |
| | Yes | | | |
| | Yes | | | |
| | Yes | | | |
| | Yes | | | |
| | Yes | | | |

STEP 3
Check the box if the response in column c of Step 2 is "Yes for any unit

☐ For each unit that will be repowered, the Repowering Extension Plan form is included and the Repowering Technology Petition form has been submitted or will be submitted by June 1, 1997.

Plant Name (from Step 1) **Brandy Branch**

STEP 4
Read the standard requirements and certification, enter the name of the designated representative, and sign and date

**Standard Requirements**

Permit Requirements.

(1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Submit a complete Acid Rain part application (including a compliance plan) under 40 CFR part 72, Rules 62-214.320 and 330, F.A.C. in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain part application and issue or deny an Acid Rain permit;
(2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain part application or a superseding Acid Rain part issued by the permitting authority; and
(ii) Have an Acid Rain Part.

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1)(i) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements. The owners and operators of the source and each Acid Rain unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements.

(1) The designated representative of an Acid Rain unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an Acid Rain unit that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

Plant Name (from Step 1) **Brandy Branch**

Recordkeeping and Reporting Requirements (cont)

(iv) Copies of all documents used to complete an Acid Rain part application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an Acid Rain source and each Acid Rain unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain part application, an Acid Rain part, or a written exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR parts 72, 73, 75, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities. No provision of the Acid Rain Program, an Acid Rain part application, an Acid Rain part, or a written exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

***Certification***

I am authorized to make this submission on behalf of the owners and operators of the Acid Rain source or Acid Rain units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

| | | | |
|---|---|---|---|
| Name | Jon P. Eckenbach | | |
| Signature | [signature] | Date | 12-14-99 |

STEP 5 (optional)
Enter the source AIRS
FINDS identification

| |
|---|
| AIRS |
| FINDS |

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

EPA

# Certificate of Representation



For more information, see instructions and refer to 40 CFR 72.24

This submission is: [X] New [ ] Revised (revised submissions must be completed in full; see instructions)

This submission includes combustion or process sources under 40 CFR part 74 [ ]

**STEP 1**
**Identify the source by plant name, State, and ORIS code.**

| Plant Name | State | ORIS Code |
|---|---|---|
| Brandy Branch | FL | 7846 |

**STEP 2**
**Enter requested information for the designated representative.**

Name: Jon P. Eckenbach

Address: 21 West Church Street
Jacksonville, Florida 32202

Phone Number: (904) 665-6315

Fax Number: (904) 554-7366

E-mail address (if available): eckejp@jea.com

**STEP 3**
**Enter requested information for the *alternate* designated representative, if applicable.**

Name: Tim E. Perkins

Phone Number: (904) 665-4520

Fax Number: (904) 665-7376

E-mail address (if available): perkte@jea.com

**STEP 4**
**Complete Step 5, read the certifications, and sign and date. For a designated representative of a combustion or process source under 40 CFR part 74, the references in the certifications to "affected unit" or "affected units" also apply to the combustion or process source under 40 CFR part 74 and the references to "affected source" also apply to the source at which the combustion or process source is located.**

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the affected source and each affected unit at the source.

I certify that I have given notice of the agreement, selecting me as the 'designated representative for the affected source and each affected unit at the source identified in this certificate of representation, in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice.

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and of each affected unit at the source and that each such owner and operator shall be fully bound by my actions, inactions, or submissions.

I certify that I shall abide by any fiduciary responsibilities imposed by the agreement by which I was selected as designated representative or alternate designated representative, as applicable.

I certify that the owners and operators of the affected source and of each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under life-of-the-unit, firm power contractual arrangements, I certify that:

> I have given a written notice of my selection as the designated representative or alternate designated representative, as applicable, and of the agreement by which I was selected to each owner and operator of the affected source and of each affected unit at the source; and
>
> Allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement or, if such multiple holders have expressly provided for a different distribution of allowances by contract, that allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

The agreement by which I was selected as the alternate designated representative, if applicable, includes a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative.

Plant Name (from Step 1) **Brandy Branch**

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

| | |
|---|---|
| Signature (designated representative) | Date 12-14-99 |
| Signature (alternate designated representative) J E Perkins | Date 12-16-99 |

**STEP 5**
**Provide the name of every owner and operator of the source and identify each affected unit (or combustion or process source) they own and/or operate.**

| Name JEA | | | | | [X] Owner | [X] Operator |
|---|---|---|---|---|---|---|
| ID# 001 | ID# 002 | ID# 003 | ID# | ID# | ID# | ID# |
| ID# | ID# | ID# | ID# | ID# | ID# | ID# |

| Name | | | | | [ ] Owner | [ ] Operator |
|---|---|---|---|---|---|---|
| ID# | ID# | ID# | ID# | ID# | ID# | ID# |
| ID# | ID# | ID# | ID# | ID# | ID# | ID# |

| Name | | | | | [ ] Owner | [ ] Operator |
|---|---|---|---|---|---|---|
| ID# | ID# | ID# | ID# | ID# | ID# | ID# |
| ID# | ID# | ID# | ID# | ID# | ID# | ID# |

| Name | | | | | [ ] Owner | [ ] Operator |
|---|---|---|---|---|---|---|
| ID# | ID# | ID# | ID# | ID# | ID# | ID# |
| ID# | ID# | ID# | ID# | ID# | ID# | ID# |