Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

August 11, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. R. Douglas Neeley, Chief
Air, Radiation Technology Branch
US EPA Region IV
61 Forsyth Street
Atlanta, GA 30303

Re: PSD Review and Custom Fuel Monitoring Schedule
JEA Brandy Branch Facility
PSD-FL-267

Dear Mr. Neeley:

Enclosed is a copy of the draft permit to construct (the Department's Intent to Issue package was already mailed to Mr. Greg Worley) the JEA Brandy Branch Power Plant in Duval County. It will be a natural gas and oil-fired simple cycle facility consisting of three nominal 170-megawatt (MW) simple cycle combustion turbine-electrical generators.

The project is not subject to the Florida's Power Plant Siting procedure because it will generate no electricity from steam.

Please send your written comments on or approval of the applicant's proposed custom fuel monitoring schedule. The plan is based on the letter dated January 16, 1996 from Region V to Dayton Power and Light. The Subpart GG limit on SO_2 emissions is 150 ppmvd @ 15% O_2 or a fuel sulfur limit of 0.8% sulfur. Neither of these limits could conceivably be violated by the use of pipeline quality natural gas which has a maximum SO_2 emission rate of 0.0006 lb/MMBtu (40 CFR 75 Appendix D Section 2.3.1.4). The sulfur content of pipeline quality natural gas in Florida has been estimated at a maximum of 0.003 % sulfur. Fuel oil with a 0.05% sulfur content will be used as a backup. The requirements have been incorporated into the enclosed draft permit as Specific Conditions 44 and 45 and read as follows:

44. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 or superior grade fuel oil received at the Brandy Branch Power Plant, an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

45. Natural Gas Monitoring Schedule: The following custom monitoring schedule for natural gas is approved (pending EPA concurrence) in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):

- The permittee shall apply for an Acid Rain permit when the deadlines specified in 40 CFR 72.30.
- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant of 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USAEPA.

JEA shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.

This custom fuel-monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

Please comment on Specific Conditions 30 and 41 which allow the use of the acid rain NO_X CEMS for demonstrating compliance as well as reporting excess emissions, as well as Specific Condition 42 which allows the use of CEMS in lieu of measuring the water to fuel ratio. Typically NO_X emissions will be less than 11 ppmvd @15% O_2 (natural gas) which is less than one-tenth of the applicable Subpart GG limit based on the efficiency of the unit. A CEMS requirement is stricter and more accurate than any Subpart GG requirement for determining excess emissions.

The Department recommends your approval of the custom fuel monitoring schedule and these NO_X monitoring provisions. We also request your comments on the Intent to Issue. If you have any questions on these matters please contact Michael P. Halpin, P.E. at 850/921-9530.

Sincerely,

8/11

A. A. Linero, P.E., Administrator
New Source Review Section

AAL/mph

Enclosures

Z 333 618 123

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PSD-F1-267
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Doug Neeley, Chief
Air, Radiation Tech. Br.
US EPA Region 4
61 Forsyth St.
Atlanta, GA 30303

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BUREAU OF AIR REGULATION

Jacksonville Electric Authority
Brandy Branch Facility

B&V Project 60903
B&V File 32.0203
August 3, 1999

Christopher R. Carlson
Division of Air Resources Management
Department of Environmental Protection
2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400

Subject: Additional SO_2 Impact Analysis

Dear Mr. Carlson:

Enclosed with this letter is the Revised Okefenokee Wilderness Area SO_2 Impact Analysis for Jacksonville Electric Authority you requested. This report summarizes all modeling that was preformed for this analysis. The additional ten receptors you requested were included into the modeling files and the results of the new modeling runs are presented in table format.

If you have any questions, feel free to contact me at (913) 458-9194 or e-mail me at dilloncg@bv.com.

Very truly yours,

BLACK & VEATCH

Chris G. Dillon

Chris G. Dillon
Air Quality Scientist
Black & Veatch

cgd
Enclosure[s]

cc: Ellen Porter, National Park Service
Bert Gianazza, Jacksonville Electric Authority

Revised Okefenokee Wilderness Area SO_2 Impact Analysis for Jacksonville Electric Authority

At the request of the Florida Department of Environmental Protection (FDEP), an additional Class I impact analysis was conducted for the Jacksonville Electric Authority (JEA) Brandy Branch Project. This analysis included 26 additional Putnam County SO_2 sources and 10 additional receptor locations in the Okefenokee Wilderness Area. These sources and receptors were not included in the original Class I impact analysis. This additional impact analysis consists of Prevention of Significant Deterioration (PSD) Significant Impact Level (SIL) and Increment modeling for SO_2 in the Class I area only.

All modeling was conducted using the currently requested permit limitation of a maximum of 16 hours of fuel oil firing and 8 hours of natural gas firing per day. A spreadsheet containing the enveloped emissions used in the modeling can be found in Attachment A. This modification changes the previously used 24-hour emission rate, but does not effect the 3-hour values. The 3-hour values are unchanged due to the fact the 3-hour averaging period can occur during periods of fuel oil firing only. To obtain the new 24-hour emission rate the following equation was used:

FO emission rate (g/s) * (16hrs/24hrs) + NG emission rate (g/s) * (8hrs/24hrs)
= New 24-hour emission rate (g/s)

In addition, the PSD SILs modeling was run for all ambient temperatures (20° F, 59° F, and 95° F) and across all three loads (50%, 75%, and 100%). Following the initial PSD SIL analysis, additional modeling was completed only for the operating scenarios where exceedances occurred.

Revised PSD SIL modeling results, including the 10 new receptor locations for Okefenokee, are shown in Tables 1 through 5. The tables contain a total of 41 exceedances of the Class I SILs (Class I SILs are calculated as 4 percent of the PSD Class I SO_2 Increment). These 41 exceedances were then modeled against the Class I Increment values. The PSD Increment modeling results include all significant sources of SO_2 in this area, as well as the proposed

Brandy Branch Project, and are shown in Tables 6 and 7. These tables also present the operating scenarios that exceed the Class I SILs. As discussed in Section 5.3.1 of the Air Permit Application, the values presented in Tables 6 and 7 are the highest second-high model-predicted values. The results indicate that SO_2 Class I Increment values were exceeded 18 times at Okefenokee.

Additional modeling was then performed to determine if the proposed Brandy Branch Project was a significant contributor to any of the 18 modeled exceedances. This determination was made by modeling only the proposed Brandy Branch Project's emissions at each receptor location and period having a modeled Class I Increment exceedance. The resulting maximum predicted concentrations were then compared to the Class I SO_2 SIL. The results show that the proposed Project has no significant contribution to any modeled exceedance at Okefenokee. The results of this modeling, shown in Tables 8 and 9, indicate that the maximum predicted impacts from the proposed Brandy Branch Project were all significantly below the applicable Class I SO_2 SILs. Therefore, operation of the proposed Project will not cause or contribute to an exceedance of the Okefenokee Wilderness Area Class I SO_2 Increment.

Table 1

ISCST3 Model Predicted SO_2 Concentrations for Class I SILs at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
3951FO	3-Hour	100	1984	0.998	1.000
3957FO		75		0.934	1.000
3955FO		50		0.860	1.000
3591FO		100		**1.060**	1.000
3597FO		75		0.998	1.000
3595FO		50		0.908	1.000
3201FO		100		**1.098**	1.000
3207FO		75		**1.037**	1.000
3205FO		50		0.941	1.000
24951FO	24-Hour	100		0.150	0.200
24957FO		75		0.143	0.200
24955FO		50		0.132	0.200
24591FO		100		0.158	0.200
24597FO		75		0.152	0.200
24595FO		50		0.142	0.200
24201FO		100		0.164	0.200
24207FO		75		0.157	0.200
24205FO		50		0.144	0.200

*Calculated as 4 percent of the PSD Class I Increment

Table 2

ISCST3 Model Predicted SO_2 Concentrations for Class I SILs at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m^3)	Class I SIL* (μg/m^3)
3951FO	3-Hour	100	1985	**1.075**	1.000
3957FO		75		**1.009**	1.000
3955FO		50		**1.009**	1.000
3591FO		100		**1.149**	1.000
3597FO		75		**1.068**	1.000
3595FO		50		0.990	1.000
3201FO		100		**1.194**	1.000
3207FO		75		**1.105**	1.000
3205FO		50		**1.027**	1.000
24951FO	24-Hour	100		0.168	0.200
24957FO		75		0.159	0.200
24955FO		50		0.144	0.200
24591FO		100		0.179	0.200
24597FO		75		0.169	0.200
24595FO		50		0.153	0.200
24201FO		100		0.185	0.200
24207FO		75		0.176	0.200
24205FO		50		0.159	0.200

*Calculated as 4 percent of the PSD Class I Increment

Table 3

ISCST3 Model Predicted SO_2 Concentrations for Class I SILs at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m^3)	Class I SIL* (μg/m^3)
3951FO	3-Hour	100	1986	**1.243**	1.000
3957FO		75		**1.167**	1.000
3955FO		50		**1.052**	1.000
3591FO		100		**1.328**	1.000
3597FO		75		**1.244**	1.000
3595FO		50		**1.121**	1.000
3201FO		100		**1.381**	1.000
3207FO		75		**1.293**	1.000
3205FO		50		**1.166**	1.000
24951FO	24-Hour	100		0.188	0.200
24957FO		75		0.179	0.200
24955FO		50		0.163	0.200
24591FO		100		0.198	0.200
24597FO		75		0.190	0.200
24595FO		50		0.173	0.200
24201FO		100		**0.205**	0.200
24207FO		75		0.197	0.200
24205FO		50		0.180	0.200

*Calculated as 4 percent of the PSD Class I Increment

Table 4

ISCST3 Model Predicted SO_2 Concentrations for Class I SILs at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m^3)	Class I SIL* (μg/m^3)
3951FO	3-Hour	100	1987	**1.196**	1.000
3957FO		75		**1.128**	1.000
3955FO		50		**1.017**	1.000
3591FO		100		**1.268**	1.000
3597FO		75		**1.203**	1.000
3595FO		50		**1.084**	1.000
3201FO		100		**1.312**	1.000
3207FO		75		**1.249**	1.000
3205FO		50		**1.127**	1.000
24951FO	24-Hour	100		0.163	0.200
24957FO		75		0.154	0.200
24955FO		50		0.139	0.200
24591FO		100		0.172	0.200
24597FO		75		0.164	0.200
24595FO		50		0.149	0.200
24201FO		100		0.178	0.200
24207FO		75		0.171	0.200
24205FO		50		0.154	0.200

*Calculated as 4 percent of the PSD Class I Increment

Table 5

ISCST3 Model Predicted SO_2 Concentrations for Class I SILs at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m^3)	Class I SIL* (μg/m^3)
3951FO	3-Hour	100	1988	**1.117**	1.000
3957FO		75		**1.009**	1.000
3955FO		50		0.873	1.000
3591FO		100		**1.201**	1.000
3597FO		75		**1.087**	1.000
3595FO		50		0.938	1.000
3201FO		100		**1.252**	1.000
3207FO		75		**1.136**	1.000
3205FO		50		0.978	1.000
24951FO	24-Hour	100		**0.212**	0.200
24957FO		75		0.194	0.200
24955FO		50		0.168	0.200
24591FO		100		**0.227**	0.200
24597FO		75		**0.208**	0.200
24595FO		50		0.181	0.200
24201FO		100		**0.236**	0.200
24207FO		75		**0.217**	0.200
24205FO		50		0.189	0.200

*Calculated as 4 percent of the PSD Class I Increment

Table 6

ISCST3 Model Predicted 3-Hour SO_2 Concentrations for Class I Increment Analysis at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)
3591FO	3-Hour	100	1984	**28.7**	25.0
3201FO		100		**28.7**	25.0
3207FO		75		**28.7**	25.0
3951FO		100	1985	23.1	25.0
3957FO		75		23.1	25.0
3955FO		50		23.1	25.0
3591FO		100		23.1	25.0
3597FO		75		23.1	25.0
3201FO		100		23.2	25.0
3207FO		75		23.1	25.0
3205FO		50		23.1	25.0
3951FO		100	1986	21.7	25.0
3957FO		75		21.7	25.0
3955FO		50		21.7	25.0
3591FO		100		21.7	25.0
3597FO		75		21.7	25.0
3595FO		50		21.7	25.0
3201FO		100		21.8	25.0
3207FO		75		21.7	25.0
3205FO		50		21.7	25.0
3951FO		100	1987	**25.6**	25.0
3957FO		75		**25.6**	25.0
3955FO		50		**25.6**	25.0
3591FO		100		**25.6**	25.0
3597FO		75		**25.6**	25.0
3595FO		50		**25.6**	25.0
3201FO		100		**25.6**	25.0
3207FO		75		**25.6**	25.0
3205FO		50		**25.6**	25.0
3951FO		100	1988	23.5	25.0
3957FO		75		23.5	25.0
3591FO		100		23.5	25.0
3597FO		75		23.5	25.0
3201FO		100		23.5	25.0
3207FO		75		23.5	25.0

Table 7

ISCST3 Model Predicted 24-Hour SO_2 Concentrations for Class I Increment Analysis at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m^3)	Class I Increment (μg/m^3)
24201FO	24-Hour	100	1986	5.2	5.0
24951FO		100	1988	7.1	5.0
24591FO		100		7.1	5.0
24597FO		75		7.1	5.0
24201FO		100		7.1	5.0
24207FO		75		7.1	5.0

Table 8

JEA Brandy Branch CT Contributions to ISCST3 Model Predicted 3-Hour SO_2 Concentrations at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Date/Hrs	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
3591FO	3-Hour	100	1984	1-24/10-12	0.00007	25.0	1.00
3201FO		100			0.00007	25.0	1.00
3207FO		75			0.00007	25.0	1.00
3591FO		100		7-4/7-9	0.00026	25.0	1.00
3201FO		100			0.00026	25.0	1.00
3207FO		75			0.00026	25.0	1.00
3951FO		100	1987	3-30/1-3	0.00032	25.0	1.00
3957FO		75			0.00032	25.0	1.00
3955FO		50			0.00032	25.0	1.00
3591FO		100			0.00032	25.0	1.00
3597FO		75			0.00032	25.0	1.00
3595FO		50			0.00032	25.0	1.00
3201FO		100			0.00032	25.0	1.00
3207FO		75			0.00032	25.0	1.00
3205FO		50			0.00032	25.0	1.00
3951FO		100		6-22/7-9	0.00031	25.0	1.00
3957FO		75			0.00031	25.0	1.00
3955FO		50			0.00031	25.0	1.00
3591FO		100			0.00031	25.0	1.00
3597FO		75			0.00031	25.0	1.00
3595FO		50			0.00031	25.0	1.00
3201FO		100			0.00031	25.0	1.00
3207FO		75			0.00031	25.0	1.00
3205FO		50			0.00031	25.0	1.00

Table 9

JEA Brandy Branch CT Contributions to ISCST3 Model Predicted 24-Hour SO_2 Concentrations at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Date/Hrs	Receptor*	Maximum Predicted Conc. (μg/m^3)	Class I Increment (μg/m^3)	Class I SIL** (μg/m^3)
24201FO	24-Hour	100	1986	10-25/24	3	0.026	5.0	0.20
24951FO		100	1988	3-25/24	3	0.087	5.0	0.20
24591FO		100			3	0.092	5.0	0.20
24597FO		75			3	0.089	5.0	0.20
24201FO		100			3	0.095	5.0	0.20
24207FO		75			3	0.092	5.0	0.20
24951FO		100		4-3/24	4	0.090	5.0	0.20
24591FO		100			4	0.096	5.0	0.20
24597FO		75			4	0.088	5.0	0.20
24201FO		100			4	0.100	5.0	0.20
24207FO		75			4	0.092	5.0	0.20
24951FO		100		6-7/24	1	0.034	5.0	0.20
					2	0.003	5.0	0.20
					3	0.003	5.0	0.20
					4	0.002	5.0	0.20
24591FO		100			1	0.038	5.0	0.20
					2	0.003	5.0	0.20
					3	0.003	5.0	0.20
					4	0.002	5.0	0.20
24597FO		75			1	0.031	5.0	0.20
					2	0.003	5.0	0.20
					3	0.004	5.0	0.20
					4	0.002	5.0	0.20
24201FO		100			1	0.040	5.0	0.20
					2	0.003	5.0	0.20
					3	0.004	5.0	0.20
					4	0.002	5.0	0.20
24207FO		75			1	0.033	5.0	0.20
					2	0.003	5.0	0.20
					3	0.004	5.0	0.20
					4	0.002	5.0	0.20

*Receptor locations in UTM coordinates

1	383000	3384000
2	378000	3382000
3	374000	3383000
4	370000	3383000

**Calculated as 4 percent of the PSD Class I Increment

Table 9 (Cont.)

JEA Brandy Branch CT Contributions to ISCST3 Model Predicted 24-Hour SO_2 Concentrations at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Date/Hrs	Receptor*	Maximum Predicted Conc. (µg/m^3)	Class I Increment (µg/m^3)	Class I SIL** (µg/m^3)
24951FO	24-Hour	100	1988	7-3/24	4	0.046	5.0	0.20
24591FO		100			4	0.050	5.0	0.20
24597FO		75			4	0.045	5.0	0.20
24201FO		100			4	0.052	5.0	0.20
24207FO		75			4	0.047	5.0	0.20
24951FO		100		9-3/24	1	0.034	5.0	0.20
					3	0.042	5.0	0.20
					4	0.022	5.0	0.20
24591FO		100			1	0.037	5.0	0.20
					3	0.046	5.0	0.20
					4	0.025	5.0	0.20
24597FO		75			1	0.032	5.0	0.20
					3	0.040	5.0	0.20
					4	0.020	5.0	0.20
24201FO		100			1	0.039	5.0	0.20
					3	0.048	5.0	0.20
					4	0.026	5.0	0.20
24207FO		75			1	0.034	5.0	0.20
					3	0.042	5.0	0.20
					4	0.021	5.0	0.20
24951FO		100		9-9/24	1	0.083	5.0	0.20
24591FO		100			1	0.088	5.0	0.20
24597FO		75			1	0.084	5.0	0.20
24201FO		100			1	0.091	5.0	0.20
24207FO		75			1	0.087	5.0	0.20
24951FO		100		11-26/24	1	0.001	5.0	0.20
					2	0.084	5.0	0.20
24591FO		100			1	0.001	5.0	0.20
					2	0.090	5.0	0.20
24597FO		75			1	0.001	5.0	0.20
					2	0.082	5.0	0.20
24201FO		100			1	0.001	5.0	0.20
					2	0.094	5.0	0.20
24207FO		75			1	0.001	5.0	0.20
					2	0.085	5.0	0.20

*Receptor locations in UTM coordinates

1	383000	3384000
2	378000	3382000
3	374000	3383000
4	370000	3383000

**Calculated as 4 percent of the PSD Class I Increment

Attachment A

Enveloped Emissions Spreadsheet

JEA
Jacksonville, Florida
Enveloped Stack Parameters

60903 0030

4000 Hours of natural gas simple cycle operation per year
600 Hous of fuel oil simple cycle operation per year

Last Revised 03/05/99
Date Printed 08/03/99 12 40 PM

	NATURAL GAS OPERATION			**SHORT TERM**				**ANNUALIZED (d)**			
Load	**100 Percent**										
Turbine	**PG7241 (FA)**			**Representative***				**59 Degrees**			
Ambient Temperature (F)	95	59	20	**100 Pecent Load**				**100 Pecent Load**			
Exit Velocity (ft/s)	148	157	164 0	148	ft/s	45 04	m/s	156 75	ft/s	47 78	ft/s
Exit Temp (F)	1144	1116	1081	1081	F	855 93	K	1116 00	F	875 37	K
Emissions (lb/h)											
NOx (f)	71 20	79 20	84 80	85	lb/h	10 68	g/s	36 16	lb/h	4 56	g/s
CO	43 00	48 00	52 00	52	lb/h	6 55	g/s	21 92	lb/h	2 76	g/s
SO2 (a)	0 97	1 07	1.14	1	lb/h	0 14	g/s	0 49	lb/h	0 06	g/s
PM (b)	9 00	9 00	9 00	9	lb/h	1 13	g/s	4 11	lb/h	0 52	g/s
VOC (c)	2 60	2 80	3 00	3	lb/h	0 38	g/s	1 28	lb/h	0 16	g/s
Load	**75 Percent**										
Turbine	**PG7241 (FA)**			**Representative**				59 Degrees			
Ambient Temperature (F)	95	59	20	**75 Pecent Load**				**75 Pecent Load**			
Exit Velocity (ft/s)	124	130	133	124	ft/s	37 85	m/s	129 71	ft/s	39 54	m/s
Exit Temp (F)	1170	1139	1112	1112	F	873 15	K	1139 00	F	888 15	K
Emissions (lb/h)											
NOx (f)	58 40	63 20	67 20	67	lb/h	8 47	g/s	28 86	lb/h	3 64	g/s
CO	36 00	39 00	41 00	41	lb/h	5 17	g/s	17 81	lb/h	2 24	g/s
SO2 (a)	1	0 86	0 92	1	lb/h	0 12	g/s	0 39	lb/h	0 05	g/s
PM (b)	9 00	9 00	9 00	9	lb/h	1 13	g/s	4 11	lb/h	0 52	g/s
VOC (c)	2 20	2	2	2	lb/h	0 30	g/s	1 00	lb/h	0 13	g/s
Load	**50 Percent**										
Turbine	**PG7241 (FA)**			**Representative**				59 Degrees			
Ambient Temperature (F)	95	59	20	**50 Pecent Load**				**50 Pecent Load**			
Exit Velocity (ft/s)	106	111	113	106	ft/s	32 42	m/s	110 53	ft/s	33 69	m/s
Exit Temp (F)	1200	1164	1160	1160	F	899 62	K	1164 00	F	913 15	K
Emissions (lb/h)											
NOx (f)	46 40	50 40	52.80	53	lb/h	6 65	g/s	23 01	lb/h	2 90	g/s
CO	30 00	33 00	34 00	34	lb/h	4 28	g/s	15 07	lb/h	1 90	g/s
SO2 (a)	1	1	1	1	lb/h	0 09	g/s	0 32	lb/h	0 04	g/s
PM (b)	9 00	9 00	9 00	9	lb/h	1.13	g/s	4 11	lb/h	0 52	g/s
VOC (c)	1 80	1 80	2 00	2	lb/h	0 25	g/s	0 82	lb/h	0 10	g/s

	FUEL OIL OPERATION			**SHORT TERM**				**ANNUALIZED (d)**				**Total Annual Dual Fuel Parameters (e)**			
Load	**100 Percent**														
Turbine	**PG7241 (FA)**			**Representative***				**59 Degrees**							
Ambient Temperature (F)	95	59	20	**100 Pecent Load**				**100 Pecent Load**				**100 Pecent Load**			
Exit Velocity (ft/s)	152	162	168 04	152	ft/s	46 27	m/s	161 60	ft/s	49 26	m/s	156 75	ft/s	47 78	m/s
Exit Temp (F)	1133	1098	1068	1068	F	848 71	K	1098 00	F	865 37	K	1116 00	F	875 37	K
Emissions (lb/h)															
NOx (f)	286 00	318 00	338 00	338	lb/h	42 59	g/s	29 04	lb/h	3 66	g/s	65 21	lb/h	8 22	g/s
CO	59 00	65 00	69 00	69	lb/h	8 69	g/s	5 94	lb/h	0 75	g/s	27 85	lb/h	3 51	g/s
SO2 (a)	88 38	98 21	104 30	104	lb/h	13 14	g/s	8 97	lb/h	1 13	g/s	9 46	lb/h	1 19	g/s
PM (b)	17 00	17 00	17 00	17	lb/h	2 14	g/s	1 55	lb/h	0 20	g/s	5 66	lb/h	0 71	g/s
VOC (c)	2 60	3 00	3 00	3	lb/h	0 38	g/s	0 27	lb/h	0 03	g/s	1 55	lb/h	0 20	g/s
Load	**75 Percent**														
Turbine	**PG7241 (FA)**			**Representative**				59 Degrees							
Ambient Temperature (F)	95	59	20	**75 Pecent Load**				**75 Pecent Load**				**75 Pecent Load**			
Exit Velocity (ft/s)	126 43	132	135	126	ft/s	38 54	m/s	131 67	ft/s	40 13	m/s	129 71	ft/s	39 54	m/s
Exit Temp (F)	1200	1194	1183	1183	F	912 59	K	1194 00	F	918 71	K	1139 00	F	888 15	K
Emissions (lb/h)															
NOx (f)	232 00	256 00	271 00	271	lb/h	34 14	g/s	23 38	lb/h	2 95	g/s	52 24	lb/h	6 58	g/s
CO	47 00	50 00	51 00	51	lb/h	6 43	g/s	4 57	lb/h	0 58	g/s	22 37	lb/h	2 82	g/s
SO2 (a)	72 32	79 69	84 44	84	lb/h	10 64	g/s	7 28	lb/h	0 92	g/s	7 67	lb/h	0 97	g/s
PM (b)	17 00	17 00	17 00	17	lb/h	2 14	g/s	1 55	lb/h	0 20	g/s	5 66	lb/h	0 71	g/s
VOC (c)	2 20	2	2	2	lb/h	0 30	g/s	0 20	lb/h	0 03	g/s	1 21	lb/h	0 15	g/s
Load	**50 Percent**														
Turbine	**PG7241 (FA)**			**Representative**				59 Degrees							
Ambient Temperature (F)	95	59	20	**50 Pecent Load**				**50 Pecent Load**				**50 Pecent Load**			
Exit Velocity (ft/s)	108 45	112	113	108	ft/s	33 06	m/s	112 04	ft/s	34 15	m/s	110 53	ft/s	33 69	m/s
Exit Temp (F)	1200	1200	1200	1200	F	922 04	K	1200 00	F	922 04	K	1164 00	F	913 15	K
Emissions (lb/h)															
NOx (f)	182 00	199 00	209 00	209	lb/h	26 33	g/s	18 17	lb/h	2 29	g/s	41 19	lb/h	5 19	g/s
CO	74 00	63 00	57 00	74	lb/h	9 32	g/s	5 75	lb/h	0 72	g/s	20 62	lb/h	2 62	g/s
SO2 (a)	57 30	62 70	65 90	66	lb/h	8 30	g/s	5 73	lb/h	0 72	g/s	6 04	lb/h	0 76	g/s
PM (b)	17 00	17 00	17 00	17	lb/h	2 14	g/s	1 55	lb/h	0 20	g/s	5 66	lb/h	0 71	g/s
VOC (c)	1 80	1 80	2 00	2	lb/h	0 25	g/s	0 16	lb/h	0 02	g/s	0 99	lb/h	0 12	g/s

NOTE:

(a) SO2 values were calculated based on 0 2 gr/100 scf in the natural gas and #2 distillate fuel oil (0 05% sulfur)
Example Calculations
Natural gas 100 percent load at 95F = (1,468 9 MBtu/hr)*(lb/23 8 ft^3)*(20,675 Btu/lb)*(0 2gr/100scf)*(1lb/7000gr)*(64SO2/32S)*(10^6Btu/MBtu) = 0 97 lb/hr.
#2 Dist Fuel Oil 100 percent load @ 95F = (0.05lb S/100lb fuel)*(64 lb SO2/32 lb S)*(7 05 lb fuel/1gal)*(1gal/7 05 lb)*(lb/ 18,550 Btu)*(1,639 4 MBtu/hr)*(10^6 BTU/MBtu) = 88 38 lb/hr

(b) PM emission values are for front half filterable emissions only

(c) VOC emissions represent 20% of the UHC emissions

(d) Annualized emission rate based on specific number of hours of Natural Gas and Fuel Oil operation

(e) Exit Velocity and Exit Temperature values are from the annualized natural gas operating scenarios
The emission rate values are annualized @ 59 F based on the number of hour of fuel specific firing

(f) NOx emission values for natural gas firing are at 12 ppm and 42 ppm for fuel oil firing

Modeling File Description

Included with the write-up for the additional Okefenokee SO_2 Increment analysis are two computer diskettes. These two diskettes contain the modeling files used in the Increment analysis.

Diskette one contains the first Class I SIL analysis in the folder titled "Okefenokee SIL Analysis". This folder contains the files for the five years modeled in the SIL analysis. Also, included on the first diskette is the Class I Increment analysis in the folder titled "Okefenokee Increment Analysis". This folder contains the files for the five years modeled in the Increment analysis.

Diskette two contains the second Class I SIL analysis in the folder titled "Okefenokee 2nd SIL Analysis". This folder contains two zip files (24-hour and 3-hour). These two subfolders contain the files used to determine if the Brandy Branch Project was a significant contributor to modeled Increment exceedances. Also, included on the second diskette is the meteorological data folder "metdata", which contains the data set used to run the ISCST3 model.

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 29-Jul-1999 02:04pm
From: Mike Halpin TAL 850/488-0114
HALPIN_M@A1
Dept:
Tel No:

Subject: JEA Brandy Branch

Al / Teresa -

Here's the (unscrubbed) numbers for comparing the Southside Station's emissions to Brandy Branch (numbers are in TPY):

	SOUTHSIDE STATION			
	'97/98	'98/'99	BRANDY BRANCH	Difference
TOTAL SO2 (TONS)	902.3	1224.8	124.3	(778)
TOTAL NOx (TONS)	735.5	852.1	857.7	122
TOTAL PM (TONS)	74.9	100.1	74.5	(0.4)
TOTAL CO (TONS)	54.2	63.0	366.2	312

The "Difference" column compares the '97/'98 data (as it is more conservative), but even so I believe that this helps in our efforts to describe our current "Intent to Issue" plans. We're looking at net reductions in PM and SO2, with net NOx values that nearly clear the PSD Significance Level hurdle (and likely do if we look at '98/'99 data).

I have asked Bert if they would be willing to accept a 0.04%S content limit in their oil, if we were agreeable to a liberal averaging period. This will help even more towards mitigating the regional haze issue.

Let me know your thoughts on all of this.

Al - Are you drafting the Intent to Issue? I can put some of this in there if you'd like me to take a shot at starting it.

Mike

SOUTHSIDE GENERATING STATION

UNIT #4	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**
GAS BURNED (KCF)	148,883	47,214	21,104	97,903	235,079	445,007
BTU/FT3	1,045	1,046	1,048	1,052	1,054	1,059
OIL BURNED (BBL)	15,821	24,880	-	15,858	1,551	128,515
% SULFUR	1.00	0.98	0.98	0.98	0.91	0.98
BTU/BBL	6,324,394	6,371,392	6,351,470	6,390,942	6,400,606	6,353,133
UNIT #5						
GAS BURNED (KCF)	1,069,301	952,476	1,536,930	608,681	947,953	850,228
BTU/FT3	1,042	1,046	1,048	1,051	1,055	1,060
OIL BURNED (BBL)	208,328	110,024	11,050	84,090	89,625	341,468
% SULFUR	0.99	0.98	0.98	0.98	0.95	0.98
BTU/BBL	6,336,048	6,367,616	6,351,470	6,387,219	6,395,450	6,359,145
TOTAL MBTU	2,689,829	1,904,787	1,703,003	1,381,166	1,830,983	4,360,422

Site oil consumption (BBLS)	224,149	134,904	11,050	99,948	91,176	469,983
Site oil consumption (MBTU)	1,420,034	859,111	70,184	638,449	583,120	2,987,917
Site oil SO2 emissions (TPY)	710.0	429.6	35.1	319.2	291.6	1494.0
Site gas SO2 emissions (TPY)	0.35	0.29	0.45	0.20	0.34	0.37
Average oil SO2 emissions (TPY)	Oil	Gas				
6 year average	546.6	0.3				
5 year average	513.9	0.3				
4 year average	535.0	0.3				
3 year average	701.6	0.3				
2 year average	892.8	0.4				

Brandy Branch SO2 emissions TPY	
800 hours per year oil / 4000 gas	124.3
750 hours per year oil / 4000 gas	116.9

RECIEVED 7-21-99

GE Energy Services

Marvin V. Sindel Jr.
Sales Manager

GE Energy Services Sales
General Electric International, Inc.
10 Van Dyck Rd. Jacksonville, FL. 32218
*Tel: 904-757-2620, Dial Comm: 8*585-2620*
Fx: 904-757-2652
Email: marvin.sindel@ps.ge.com

1/28/99

Subject: GE Frame 7FA Gas Turbine NOx Guarantee for JEA

Mr. Jim Connolly, P.E.
JEA
21 West Church Street
Jacksonville, FL. 32202

Dear Jim,

Pursuant to your question on the NOx emission guarantee for the three GE Frame 7FA units that JEA has purchased to be installed at the Brandy Branch Station, the following information is offered:

1. The GE guarantee for the units purchased is 15 ppm NOx. GE will guarantee this level only for the "new and clean" test performed immediately after the installation of the unit is complete. This guarantee is similar to GE guaranteeing the performance of the unit at the "new and clean" condition.

2. The unit will operate at the 15 ppm level only for load conditions above 50% load. Should JEA use the units in their peaking mode for load control and operate the unit below this load point, the NOx level will exceed the 15 ppm .

3. The current NOx guarantee is for 15 ppm. However, with some additional modifications, GE is able to offer an improved guarantee of 9 ppm NOx. The price adder to change the contractual guarantee to 9 ppm NOx is $300,000.00 per unit.

I hope this answers your questions concerning the GE units contractual guarantee concerning NOx emissions. Should you have any further questions regarding the GE units, please contact me at your convenience.

Respectfully,

Marvin Sindel
Sales Manager

cc: J. Grassman - GE Schenectady

GE Power Systems

Marvin V. Sindel Jr.
Sales Manager

GE Power Systems Sales
10 Van Dyck Rd. Jacksonville, FL 32218
*Tel: 904-757-2620, Dial Comm: 8*585-2620*
Fx: 904-757-2652
Email: marvin.sindel@ps.ge.com

2/10/99

Subject: GE/JEA Agreement on 9 ppm NOx for Brandy Station Gas Turbines

Mr. Jim Connolly
JEA
21 West Church Street
Jacksonville, FL. 32202

Dear Jim

GE has agreed to the following offer to JEA:

Modification of the 3 Gas Turbines to be installed at the Brandy Branch Station to allow for 9 ppm NOx operation on gas, pursuant to our limitations at partial load of maintaining NOx levels. The unit at Kennedy Station will not be modified to this lower NOx level guarantee.

In return JEA will allow GE to modify the shipping schedule for the 3rd unit at Brandy Branch (this is the final unit of the 4 gas turbines JEA has purchased) from a January 2001 date to a March 2001 date.

The guarantees and liquidated damages of the contract will be modified to reflect the new guarantee of 9ppm NOx at full load on gas and the shipment of the final gas turbine to March 2001.

Please confirm in writing JEA's acceptance of this offer. Should you have any questions, please contact me at your convenience.

Respectfully,

Marv Sindel

GE-JEA-04

Date Received: 2/10/99
Project/WRN : 60903
Title: 9 PPM NOx AGREEMENT
File(s) 63.1003

Name	Action	Info

Keywords NOx, AIR EMISSIONS

BLACK & VEATCH
JEA Tower, 21 West Church Street, Tower 10, Jacksonville, Florida 32202-3139, (904) 665-7446

JEA
Kennedy/Brandy Branch Combustion Turbine Project

B&V Project 29686/60903
B&V File 62.1003/14.0200
February 26, 1999

Subject: Conformed Specification – Rev. 4

General Electric Co.
1 River Road, Building 23, Room 211
Schenectady, New York 12345

Attention: Mr. J. T. Grassmann
Project Manager

Dear Mr. Grassmann:

The combustion turbine generator (CTG) conformed specifications for the JEA Kennedy and Brandy Branch projects have been revised to incorporate the following changes.

- Ref.: GE Letter dated 2/10/99 from Marv Sindel to Jim Connolly.
  JEA E-mail dated 2/11/99 from Jim Connolly to Marv Sindel.
  Change NOx guarantee on natural gas for 3 units for Brandy Branch from 15 to 9 ppmvd @ 15% O2 in exchange for delaying schedule for 4th unit by 2 months.
- Ref.: GE E-mail dated 2/16/99 from John Almstead to Rick Tetzloff.
  Provided estimated (not guaranteed) starting times.

The following sections have been revised and 9 copies are enclosed.

- Section IV – General Conditions. Termination payment schedule and invoicing and payment terms schedule revised for 2 month delay for 4th unit.
- Section V – Special Conditions. Payment schedule revised for 2 month delay for 4th unit.
- Section VI, Subsection 1.1 – General Description and Scope of the Work. Delivery and operation of the unit schedules revised for 2 month delay for 4th unit.
- Attachment 1 – Technical Data Sheets. NOx emissions revised to state that the Kennedy unit is guaranteed for 15 ppm and that the Brandy Branch units are guaranteed for 9 ppm. Added starting times to data sheets and changed "guaranteed" to "estimated".

New text is shown with underlining and deleted text is shown with strikethrough. Lines that contain revisions have a vertical line in the margin. If you have any questions, please let us know.

Very truly yours,

BLACK & VEATCH CORP.

Rick Tetzloff, P.E.

rct

cc : (all with attachment)
Marv Sindel, GE
Jim Connolly, JEA
Eddie Mims, JEA (3 copies)
Dave Larson, FD
Gene Bergt, B&V
Dale Isley, B&V
Dick Ward, B&V
Ken Weiss, B&V

SECTION IV - GENERAL CONDITIONS

TABLE OF CONTENTS

Subsection Page

SECTION IV - GENERAL CONDITIONS

1. RESERVATIONS

1.1. The Jacksonville Electric Authority (JEA) reserves the right to cancel any Contract if there is a failure at any time to perform adequately the stipulations of the bid, and the conditions and specifications which are attached and made a part of this Contract, or in any case of any attempt to willfully impose upon JEA materials or products or workmanship which is, in the opinion of JEA, of an unacceptable quality. Any action taken in pursuance of this latter stipulation shall not affect or impair any rights or claim of JEA to damages for the breach of the Contract.

1.2. Should the Contractor fail to comply with the conditions of this Contract or fail to complete the required work or furnish the required materials within the time stipulated in the Contract, JEA reserves the right to purchase in the open market, or to complete the required work, at the expense of the Contractor or by recourse to provisions of the faithful performance bond if such bond is required under the conditions of the bid.

1.3. Should the Contractor fail to furnish any item or items, or to complete the required work included in this Contract, JEA reserves the right to withdraw such items or required work from the operation of this Contract without incurring further liabilities on the part of JEA thereby.

1.4. All items furnished must be completely new and free from defects unless specified otherwise.

2. CANCELLATION

2.1. Termination for Convenience for the equipment shall be in accordance with the Termination Schedule under Tab 4 of the Commercial Volume of IPS70600.

2.2 JEA may terminate this contract at any time upon written notice to GE and payment of termination charges in accordance with the schedule. Title to any terminated gas turbine equipment shall remain with GE.

Termination Payment Schedule

Project Month	Calendar Month	Milestone	Unit 1 %	Unit 2 %	Unit 3 %	Unit 4 %
0	June'98	After Notice to Proceed	0.60%	0.00%	0.00%	
1st Month	July '98		2.25%	0.60%	0.20%	
2nd Month	Aug. '98		3.75%	1.50%	0.60%	
3rd Month	Sept. '98		5.25%	2.25%	1.50%	
4th Month	Oct. '98		7.50%	3.00%	2.25%	~~3.00%~~
5th Month	Nov. '98		10.00%	3.75%	3.00%	~~3.00%~~
6th Month	Dec. '98		12.75%	4.50%	3.75%	3.00%
7th Month	Jan. '99		15.50%	5.25%	4.50%	3.00%
8th Month	Feb. '99		18.00%	6.50%	5.25%	3.00%
9th Month	Mar. '99		20.75%	7.50%	6.00%	3.00%
10th Month	April '99		23.50%	10.00%	6.75%	3.00%
11th Month	May '99		26.50%	12.75%	7.50%	3.00%
12th Month	June '99		28.75%	15.50%	10.00%	3.00%
13th Month	July '99		31.50%	18.00%	12.75%	3.00%
14th Month	Aug. '99		34.00%	20.75%	15.50%	3.00%
15th Month	Sept. '99	Ship Unit 1	100%	23.50%	18.00%	3.00%
16th.Month	Oct.-'99	Delivery Unit 1	100%	26.50%	20.75%	3.00%
17th Month	Nov.-'99			28.75%	23.50%	3.00%
18th Month	Dec.-'99			31.50%	26.50%	3.00%
19th Month	Jan.-'00			34.00%	28.75%	~~3.75~~ 3.00%
20th Month	Feb.-'00	Ship Unit 2		100%	31.50%	~~6.00~~ 3.00%
21st Month	Mar.-'00	Delivery Unit 2		100%	34.00%	~~10.00~~ 3.75%
22nd Month	Apr.-'00	Ship Unit 3			100%	~~12.75~~ 6.00%
23rd Month	May-'00	Delivery Unit 3			100%	~~15.50~~ 10.00%
24th Month	June-'00					~~18.00~~ 12.75%
25th Month	July-'00					~~20.75~~ 15.50%
26th Month	Aug.-'00					~~23.50~~ 18.00%
27th Month	Sept.-'00					~~26.50~~ 20.75%
28th Month	Oct.-'00					~~28.75~~ 23.50%
29th Month	Nov.-'00					~~31.50~~ 26.50%
30th Month	Dec.-'00					~~34.00~~ 28.75%
31st Month	Jan.-'01	~~Ship Unit 4~~				~~100.00~~ 31.50%
32nd Month	Feb.-'01	~~Delivery Unit 4~~				~~100.00~~ 34.00%
33rd Month	Mar.-'01	Ship Unit 4				100.00%
34th Month	Apr.-'01	Delivery Unit 4				100.00%

3. TAXES

3.1. The JEA is authorized to self-accrue the Florida Sales and Use Tax (Direct Payment Certificate Number TPP 0138) when purchasing tangible personal property without the payment of Florida sales and use tax to the supplier of such property.

3.2. Buyer shall be responsible for, and shall pay directly when due and payable, any and all Buyer Taxes (defined below), and all payments due and payable by Buyer to Seller hereunder shall be made in the full amount of the Contract Price, free and clear of all deductions and withholding, for Buyer Taxes.

3.3. "Buyer Taxes" means all taxes, duties, fees, or other charges of any nature (including, but not limited to, ad valorem, consumption, excise, franchise, gross receipts, license, property, sales, stamp, storage, transfer, turnover, use, or value-added taxes, and any and all items of withholding, deficiency, penalty, addition to tax, interest, or assessment related thereto), other than Seller Taxes, imposed by any governmental on Seller or its employees or subcontractors due to the execution of any agreement or the performance of or payment for work hereunder.

4. INVOICING AND PAYMENT TERMS

Payment Terms will be on a per unit basis in accordance with the following schedule.

	Unit 1	Unit2	Unit3	Unit 4
Receipt of Air Permit Information - June '98	10%	10%	10%	
July '98	4.2857%			
Aug. '98	4.2857%			
Sept. '98	4.2857%			
Oct. '98	4.2857%			10%
Nov. '98	4.2857%			
Dec. '98	4.2857%			
Jan. '99	4.2857%	4.2857%		
Feb. '99	4.2857%	4.2857%		
Mar. '99	4.2857%	4.2857%	4.2857%	
Apr. '99	4.2857%	4.2857%	4.2857%	
May. '99	4.2857%	4.2857%	4.2857%	
June '99	4.2857%	4.2857%	4.2857%	
July '99	4.2857%	4.2857%	4.2857%	
Aug. '99	4.2857%	4.2857%	4.2857%	
Sept. '99 CT Shipment - Unit 1	10%	4.2857%	4.2857%	
Oct. '99 30 Days After Shipment - Unit 1	10%	4.2857%	4.2857%	
Nov. '99		4.2857%	4.2857%	~~4.2857%~~
Dec. '99		4.2857%	4.2857%	~~4.2857%~~
Jan. '00		4.2857%	4.2857%	4.2857%
Feb. '00		4.2857%	4.2857%	4.2857%
Mar. '00 CT Shipment - Unit 2		10%	4.2857%	4.2857%
Apr. '00 30 Days After Shipment - Unit 2		10%	4.2857%	4.2857%
May '00 CT Shipment - Unit 3			10%	4.2857%
June '00 30 Days After Shipment - Unit 3			10%	4.2857%
July '00				4.2857%
Aug. '00				4.2857%
Sept. '00				4.2857%
Oct. '00				4.2857%
Nov. '00				4.2857%
Dec. '00				4.2857%
Jan. '01 ~~CT Shipment – Unit 4~~				~~10.00~~ 4.2857%
Feb. '01 ~~30 Days After Shipment – Unit 4~~				~~10.00~~ 4.2857%
Mar. '01 CT Shipment – Unit 4				10.00%
Apr. '01 30 Days After Shipment – Unit 4				10.00%
Successful Completion of Performance Tests - Each Unit	10%	10%	10%	10%

Payment Terms are Net 3 Days with wire transfer

Late Fee - 0.5% per day for days 3-15.

Or 1% per month thereafter

5. VALUE ENGINEERING

During the term of the Contract, JEA and Contractor are encouraged to identify ways to reduce the total cost to JEA of the supplies or services provided by the Contractor. JEA and Contractor may negotiate Contract amendments that support and allow such reductions in total costs including, but not limited to the sharing of savings resulting from implementation of cost-reducing initiatives between JEA and Contractor.

6. MINORITY BUSINESS ENTERPRISE SUBCONTRACTOR INITIATIVE

JEA encourages Contractor to employ firms certified as JEA Minority Business Enterprise ("MBE") firms as subContractors to the maximum extent practical. During the term of the Contract, JEA and Contractor may negotiate Contract amendments that support and allow the employment of such MBE firms by Contractor including, but not limited to changes in the price to JEA of the supplies or services supplied by the Contractor.

7. NON-DISCRIMINATION PROVISIONS

Contractor shall comply with:

7.1. The provisions of Presidential Order 11246, as amended and with all rules and regulations implementing that Executive Order and the portions of Executive Orders 11701 and 11758 as applicable to Equal Employment Opportunity. Said executive orders and all rules and regulations implementing same are by this reference incorporated herein as if set out in their entirety;

7.2. The provisions of Section 503 of the Rehabilitation Act of 1973, as amended and the Americans with Disabilities Act ("ADA") and with all rules and regulations implementing such Acts. Said Acts and all rules and regulations implementing same are by this reference incorporated herein as if set out in their entirety; and

7.3. The provisions of The Employment and Training of Veterans Act, 38 U.S.C. 4212 (formerly 2012), as amended, and with all rules and regulations implementing such Act. Said Act and all rules and regulations implementing same are by this reference incorporated herein as if set out in their entirety.

7.4. Contractor agrees that if any of the obligations of this Contract are to be performed by a Sub-Contractor, then the provisions of this Subsection shall be incorporated into and become a part of the subcontract.

8. OCCUPATIONAL SAFETY AND HEALTH WARRANTY

Contractor warrants that the products sold or service rendered to JEA shall conform to the standards and regulations promulgated by the U.S. Department of Labor under the Occupational Safety and Health Act of 1970 (29 U.S.C. 651, PL91-596). In the event the product sold does not conform to the OSHA Standards and/or regulations, JEA at its option may return the product for correction or replacement at Contractor's expense or return the product at Contractor's expense and cancel the Contract. Services performed by the Contractor which do not conform to the OSHA Standards and/or regulations JEA shall notify the Seller and Seller shall remedy the nonconformance as stipulated in the Warranty Subsection of General Conditions.

9. PROTECTION OF THE ENVIRONMENT

Contractor shall bear full responsibility for the transportation, use and disposal of any hazardous or toxic substance under the Contractor's control during the performance of the Contract.

10. SUBCONTRACTING OR ASSIGNING OF CONTRACT

The Contractor shall not subcontract or assign the Contract or any portion thereof without the written consent of JEA.

11. CONTRACT DOCUMENTS

The Contract shall consist of JEA's Contract or Purchase Order Form together with these specifications and conditions including the executed Bid Form which shall be collectively referred to as the Contract Documents. This Contract is the complete agreement between the Parties. Parol or extrinsic evidence will not be used to vary or contradict the express terms of this Contract.

12. COMPLIANCE WITH CODES

The Codes and Standards that will apply will be in accordance with Tab 9 "Codes and Standards" and Tab 11 "Technical Comments" of the Technical Volume of IPS70600.

13. APPLICABLE STATE LAW

The rights, obligations and remedies of the Parties as specified under this Contract will be interpreted and governed in all respects by the laws of the State of Florida. Should any provision of this Contract be determined by the courts to be illegal or in conflict with any law of the State of Florida, the validity of the remaining provisions will not be impaired.

14. VENUE

The venue of any legal action brought by or filed against JEA relating to any matter arising under this Contract shall be exclusively in that state or federal court, sitting in Duval County, Florida which has jurisdiction over such legal action.

15. PATENTS/COPYRIGHTS

For one dollar ($1.00) acknowledged to be included and paid for in the Contract Price and other good and valuable considerations, Contractor agrees as follows:

15.1. If the JEA notifies Contractor promptly of the receipt of any claim, does not take any position adverse to Contractor regarding such claim and gives Contractor information, assistance and exclusive authority to settle an defend the claim, then Contractor shall defend, indemnify, save harmless and pay any and all awards of damages assessed against JEA and its respective members, directors, officers, agents, and employees, or any of them, from and against liability or loss, including but not limited to any claims, judgments, court costs and attorneys' fees incurred in any claims, or any pretrial, trial or appellate proceedings on account of infringements of patents, copyrighted or uncopyrighted works, secret processes, trade secrets, patented or unpatented inventions, articles or appliances, materials, or allegations thereof, pertaining to the Work, or any part thereof, combinations thereof, processes therein or the use of any tools, materials or implements used by Contractor.

15.2. Contractor shall, at its own expense, procure for JEA the right to continue use of the Work, parts tools, implements and materials or combinations thereof, or processes used therein resulting from a suit or judgment on account of patent or copyright infringement, or threats thereof.

15.3. If, in any such suit or proceeding, a temporary restraining order or preliminary injunction is granted, Contractor shall make every reasonable effort, by giving a satisfactory bond or otherwise, to secure the suspension of such restraining order or temporary injunction.

15.4. If, in any such suit or proceeding, any part of the Work is held to constitute an infringement and its use is permanently enjoined, Contractor shall, at once, make every reasonable effort to secure for JEA a license, authorizing the continued use of the Work. If Contractor fails to secure such license for JEA, Contractor shall replace the Work with non-infringing Work, or modify the Work in a way satisfactory to JEA, so that the Work is non-infringing.

15.5. The above remedies are the sole and exclusive remedies for Patent or Copyright claims.

16. WARRANTY

16.1. Contractor warrants to JEA that the Equipment to be delivered hereunder shall be designed and fit for the purpose of generating electric power when operated in accordance with Contractor's specific operation instructions and, in the absence thereof, in accordance with generally accepted operation practices of the electric power producing industry and shall be free from defects in material, workmanship and title.

16.2. The foregoing warranties (except as to title) for each Unit shall apply to defects which appear during the Warranty Period.

16.3. If the Equipment delivered hereunder does not meet the above warranties, JEA shall promptly notify Contractor in writing and make the Equipment available promptly for correction. Contractor shall thereupon correct any defect by, at its option, (i) repairing the defective Equipment or (ii) by making available necessary replacement parts FOB factory, freight prepaid to the Facility. Contractor shall provide technical advisory services reasonably necessary for such repair of the equipment including without limitation, transportation expenses of equipment and personnel to and from the jobsite, in and out expenses for Contractor's equipment, and customary expenses incidental thereto.

Installation costs, including craft labor, supervision and tools to effect the warranty repairs at the site are the responsibility of the Contractor. If a defect in the Equipment or part thereof cannot be corrected by Contractor's reasonable efforts, the Parties will negotiate an equitable adjustment in price with respect to such Equipment or part thereof.

Contractor will remove and replace all Contractor supplied equipment for the purpose of warranty repairs

16.4. Any reperformed service or repaired or replacement part furnished under this warranty shall carry warranties on the same terms as set forth above, except that the warranty period shall be for a period of one year from the date of such reperformance, repair or replacement. In any event the warranty period and Seller's responsibilities set forth herein for such repaired or replacement part shall terminate one year after the end of the Warranty Period applicable to the item of Equipment in which such repaired or replacement part was installed or in which such service was reperformed.

Warranty period will be one year from the date when the machine meets the minimum acceptable performance criteria, or two year from shipment, whichever occurs first. GE will not be responsible for the removal of any non GE supplied equipment.

The minimum acceptable performance criteria is defined as 95% of the output, and 105% of the heat rate guaranteed values.

16.5. Contractor does not warrant the Equipment or any repaired or replacement parts against normal wear and tear including that due to environment or operation, including excessive operation at peak capability, defined by a firing temperature higher than the base load design, operating outside of the manufacturer's recommendations, type of fuel, detrimental air inlet conditions or erosion, corrosion or material deposits from fluids. The warranties and remedies set forth herein are further conditioned upon (i) the proper storage, installation, operation, and maintenance of the Equipment and conformance with the operation instruction manuals (including revisions thereto) provided by Seller and/or its subcontractors, as applicable and (ii) repair or modification pursuant to Seller's instructions or approval. JEA shall keep proper records of operation and maintenance during the Warranty Period. These records shall be kept in the form of logsheets and copies shall be submitted to Contractor upon its request. Contractor does not warrant any equipment or services of others designated by JEA where such equipment or services are not normally supplied by Contractor.

Contractor recognizes that the machine will be operated under the following conditions:

200 Starts per year
400 hours operation on natural gas
100 hours operation on fuel oil

16.6. The preceding paragraphs of this Subsection 16 set forth the exclusive remedies for all claims based on failure of or defect in the Equipment provided under this Contract or Unit performance, whether the failure or defect arises before or during the Warranty Period and whether a claim, however instituted, is based on contract, indemnity, warranty, tort (including negligence), strict liability or otherwise. The foregoing warranties are exclusive and are in lieu of all other warranties and guarantees whether written, oral, implied or statutory. NO IMPLIED STATUTORY WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE SHALL APPLY

17. LIMITATION OF LIABILITY

17.1. The total liability of Contractor, on all claims of any kind, whether in contract, warranty, tort (including negligence), strict liability, indemnity, or otherwise, arising out of the performance or breach of the Contract or use of any Equipment shall not exceed the Contract Price allocable to the Equipment giving rise to the claim. All liability under this Contract shall terminate four years after the Shipment Date of the Unit giving rise to the claim. Equipment is defined as the combustion turbine generator and all auxiliary equipment as defined in JEA IFB JXF-167-98.

17.2. In no event, whether as a result of breach of contract, warranty, tort (including negligence), strict liability, indemnity, or otherwise, shall Contractor or its subcontractors or suppliers be liable for loss of profit or revenues, loss of use of the Equipment or any associated equipment, cost of capital, cost of substitute equipment, facilities, services or replacement power, downtime costs, claims of JEA's customers for such damages, or for any special, consequential, incidental, indirect or exemplary damages,and, to the extent permissible by law, JEA shall indemnify Contractor against such claims of JEA's customers.

17.3. JEA covenants and agrees that in the event it seeks to transfer or assign the Equipment and Services to any third party that it shall, as a condition to such transfer or assignment, cause such third party to acknowledge and accept the restrictions and limitations afforded under this Contract for the benefit of the Contractor, including the provisions of this Article.

17.4. If Contractor furnishes JEA with advice or assistance concerning any products, systems or work which is not required pursuant to the Specification, the furnishing of such advice or assistance will not subject Contractor to any liability, whether in contract, indemnity, warranty, tort (including negligence), strict liability or otherwise.

17.5. For the purposes of this Subsection 17, the term "Contractor" shall mean Contractor, its affiliates, subcontractors and suppliers of any tier, and their respective agents and employees, whether individually or collectively.

17.6. The provisions of this Subsection 17 shall prevail over any conflicting or inconsistent provisions contained in any of the documents comprising this Contract, except to the extent that such provisions further restrict Contractor's liability.

18. EXCUSABLE DELAYS

18.1. Contractor shall not have any liability or be considered to be in breach or default of its obligations under this Contract to the extent that performance of such obligations is delayed or prevented, directly or indirectly, due to: (i) causes beyond its reasonable control; or (ii) acts of God, act (or failures to act) of governmental authorities, fires, severe weather conditions, earthquakes, strikes or other labor disturbances, floods, war (declared or undeclared), epidemics, civil unrest, riot, delays in transportation from abnormal causes, or (iii) acts (or omissions) of JEA including failure to promptly: (a) provide Contractor with information and approvals necessary to permit Contractor to proceed with work within a reasonable amount of time and without interruption, (b) comply with the terms of payment, or (c) provide Contractor with such evidence as Contractor may request that any export or import license or permit has been issued (if such is the responsibility of JEA), or (iv) shipment to storage under Article 4 or (v) inability on account of causes beyond the reasonable control of Contractor to obtain necessary materials, necessary components or services. Contractor shall notify JEA of any such delay. The date of delivery or of performance shall be extended for a period equal to the time lost by reason of delay, plus such additional time as may be reasonably necessary to overcome the effect of such excusable delay. Contractor shall notify JEA, as soon as practicable, of the revised Delivery Date. If Contractor is delayed by acts or omissions of JEA, or by the prerequisite work of JEA's other contractors or suppliers, Contractor shall also be entitled to an equitable price adjustment. Causes associated in (i), (ii), and (iii) will make the provisions of (iv) and (v) acceptable to the Owner.

18.2. If delay excused by this Subsection 18 extends for more than one hundred and twenty (120) days and the parties have not agreed upon a revised basis for continuing the work at the end of the delay, including adjustment of the price, JEA, upon thirty (30) days written notice, may terminate the order with respect to the undelivered Equipment to which title has not yet passed and any uncompleted Services, whereupon JEA shall promptly pay Contractor its termination charges as set forth in Tab 4 of the Commercial Volume of IPS70600.

19. TITLE

19.1. Passage of Title. Title to Equipment or materials to be shipped from within the United States shall pass to JEA when available for shipment from the manufacturer's factory. Notwithstanding passage of title, Contractor shall remain responsible for risk of loss to the Equipment and materials incorporated therein until delivered to the agreed point of delivery.

19.2. Shipment to Storage. If any part of the Equipment cannot be shipped to JEA when ready due to any cause not attributable to Contractor, Contractor may ship such Equipment to storage. If such Equipment is placed in storage, including storage at the facility where manufactured, the following conditions shall apply: (a) title shall thereupon pass to JEA if it had not already passed; (b) any amounts otherwise payable to Contractor upon delivery or shipment shall be payable upon presentation of Contractor's invoices and certification of cause for storage; (c) all expenses incurred by Contractor, such as for preparation for and placement into storage, handling, inspection, preservation, insurance, storage, removal charges and any taxes shall be payable by JEA upon submission of Contractor's invoices; and (d) when conditions permit and upon payment of all amounts due hereunder, Contractor shall resume delivery of the Equipment to the originally agreed point of delivery; and (e) Contractor shall bear risk of loss.

20. INDEMNIFICATION

In consideration of Ten Dollars ($10.00) receipt and sufficiency of which is hereby acknowledged, the CONTRACTOR shall hold harmless, indemnify, and defend JEA and Black & Vetch ,its Engineer against any claim, action, loss, damage, injury, liability, cost and expense of whatsoever kind or nature (including, but not by way of limitation, attorney's fees and court costs) arising out of or injury (whether mental or corporeal) to persons, including death, or damage to property, of third parties (other than JEA), arising out of or incidental to the negligent acts or omissions of the CONTRACTOR in the performance of this contract or work performed thereunder. In the event of joint negligence on the part of JEA and the CONTRACTOR, any loss shall be apportioned in accordance with the provisions of the Uniform Contribution Among Tortfeasors Act (s. 768.31, F.S.), as that Act exists on the effective date of this contract. For purposes of this Indemnification, the term "JEA" shall include its governing board, officers, employees, agents and assigns. This indemnification shall survive the term of this AGREEMENT.

21. DELIVERY

21.1. Contractor shall be responsible for delivery of equipment, FOB accessible rail siding if by rail, and FOB jobsite if by truck. Partial deliveries shall be permitted. Contractor Technical Representative will direct the offloading of the equipment. Contractor will assist in providing handling information prior to delivery.

21.2. Title to each piece of Equipment shall pass to the Owner when the Equipment is made available for shipment at the factory or when placed in mutually acceptable storage facilities. Transportation to site and risk of loss until delivery to the site shall be the responsibility of the Contractor.

SECTION V - SPECIAL CONDITIONS

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1. LIQUIDATED DAMAGES

1.1. If Contractor fails to complete the Work in accordance with the specified contract schedule, or if the equipment fails to meet capacity, emissions, net output or heat rate requirements, Contractor shall pay JEA Liquidated Damages in accordance with the following breakdown day for each and every calendar day, including Sundays and holidays, starting on the day following the specified completion date(s) until the date(s) the item(s) of Work is completed and accepted by JEA. Time is of the essence.

1.2. Contractor agrees that said daily sum is to be paid not as a penalty, but as compensation to JEA as a fixed and reasonable liquidated damages for losses which JEA will suffer because of such default, whether through increased administrative and engineering costs, interference with JEA's normal operations, other tangible and intangible costs, or otherwise, which costs will be impossible or impracticable to measure or ascertain with any reasonable specificity.

1.3. Liquidated damages may, at JEA's option, be deducted from any monies held by JEA which are otherwise payable to Contractor.

1.4. Contractor's responsibility for Liquidated Damages shall in no way relieve Contractor of any other contractual obligations.

1.5. The maximum liability of Contractor for payment of Liquidated Damages for schedule delay shall be an amount equal to 15% of the Contract price.

1.5.1 **Schedule** - The Contractor agrees to pay Liquidated Damages in the amount of $9,000 for each calendar day that expires after October 31, 1999, until all equipment necessary for the installation and operation of the unit as outlined in JEA IFB JXF-167-98 is delivered to the Kennedy Generating Station. The Contractor shall be assessed Liquidated Damages under these provisions to which the schedule delay is attributable to the Contractor's non-compliance with the scope of work included as part of this Contract.

1.5.1.1 The amount of Liquidated Damages shall increase to $24,000 for each calendar day that expires after November 30, 1999, until all equipment necessary for the installation and operation of the Unit, as outlined in JEA IFB JXF-167-98, is delivered to the Kennedy Generating Station.

1.5.1.2 The Contractor agrees to pay Liquidated Damages in the amount of $24,000 for each calendar day that expires after the Owner scheduled date for the achievement of the minimum performance criteria, provided that the initial performance test is conducted a minimum of 30 days prior to the scheduled date of achievement of the minimum performance criteria.

For any delays in meeting the Owner scheduled date for the achievement of the minimum performance criteria, due solely to failure of Contractor supplied equipment, or acts or omissions by the Contractor, the Contractor agrees to pay liquidated damages in the amount of $24,000 for each calendar day that expires after the Owner scheduled date for the achievement of the minimum performance criteria. The minimum performance criteria is defined as 95% of the output and 105% of the heat rate on the guarantee data sheets.

1.5.1.3 If an order is placed for additional units at the time of the award of the contract, the Contractor agrees to pay Liquidated Damages in the amount of $9,000, for schedule delay, for each calendar day that expires after the dates shown on the following schedule.

First Additional Unit	April 1, 2000
Second Additional Unit	June 1, 2000

If a letter of intent is placed for a third additional unit on or before September 10, 1998, the Contractor agrees to pay Liquidated Damages in the amount of $9,000, for schedule delay, for each calendar day that expires after February 28, 2001.

The amount of Liquidated Damages shall increase to $24,000 for each calendar day that expires after 30 days from the respective delivery dates for the additional units, until all equipment necessary for the installation and operation of the unit as outlined in JEA IFB JXF-167-98 is delivered to the agreed upon site.

The Contractor agrees to pay Liquidated Damages in the amount of $24,000 for each calendar day that expires after the Owner scheduled date for the achievement of the minimum performance criteria, provided that the initial performance test is conducted a minimum of 30 days prior to the scheduled date of achievement of the minimum performance criteria.

For any delays in meeting the Owner scheduled date for the achievement of the minimum performance criteria, due solely to failure of Contractor supplied equipment, or acts or omissions by the Contractor, the Contractor agrees to pay liquidated damages in the amount of $24,000 for each calendar day that expires after the Owner scheduled date for the achievement of the minimum performance criteria. The minimum performance criteria is defined as 95% of the output and 105% of the heat rate on the guarantee data sheets.

1.5.2 **Net Electric Capacity** - The Contractor agrees to pay Liquidated Damages in the amount of $520, for each net kW, on a per unit basis, corrected to site conditions, that the combustion turbine generator fails to meet the guaranteed net electrical capacity for the greater difference for natural gas or distillate fuel, as specified in Section VI, Subsection 2.1.7. These liquidated damages shall be in addition to the Schedule Liquidated Damages, but shall not be assessed unless the Contractor fails to perform corrective measures to meet the guarantees within 90 days of the initial performance test.

1.5.3 **Net Heat Rate** - The Contractor agrees to pay Liquidated Damages in the amount of $2,425, for each net Btu/kWh (LHV), on a per unit basis, corrected to design point, that the combustion turbine generator actual heat rate exceeds the guaranteed net heat rate for the greater difference for natural gas or distillate fuel, as specified in Section VI, Subsection 2.1.7. These liquidated damages shall be in addition to the Schedule Liquidated Damages, but shall not be assessed unless the Contractor fails to perform corrective measures to meet the guarantees within 90 days of the initial performance test.

1.5.4 The liability of the Contractor for payment of liquidated damages for performance (including net electrical capacity and heat rate) is limited to 20% of the contract price of the unit giving rise to the claim.

2. TESTING AND ACCEPTANCE

Contractor will provide technical assistance in the performing of the performance test however we are not responsible for the conducting of the test , operating personnel, issuance of reports, fuel, etc.

3. QUALITY ASSURANCE

Final inspection and testing of the system shall be completed by JEA's representative referred to hereafter as the Engineer.

4. SUBMITTALS

4.1. Bidder shall submit all the information outlined in Section VI, Attachment 1 - Technical Proposal Data, with the Technical Proposal. Failure to provide all information may result in rejection of the bid.

5. Payment Schedule

Payment Terms will be on a per unit basis in accordance with the following schedule.

	Unit 1	Unit2	Unit3	Unit 4
Receipt of Air Permit Information - June '98	10%	10%	10%	
July '98	4.2857%			
Aug. '98	4.2857%			
Sept. '98	4.2857%			
Oct. '98	4.2857%			10%
Nov. '98	4.2857%			
Dec. '98	4.2857%			
Jan. '99	4.2857%	4.2857%		
Feb. '99	4.2857%	4.2857%		
Mar. '99	4.2857%	4.2857%	4.2857%	
Apr. '99	4.2857%	4.2857%	4.2857%	
May. '99	4.2857%	4.2857%	4.2857%	
June '99	4.2857%	4.2857%	4.2857%	
July '99	4.2857%	4.2857%	4.2857%	
Aug. '99	4.2857%	4.2857%	4.2857%	
Sept. '99 CT Shipment - Unit 1	10%	4.2857%	4.2857%	
Oct. '99 30 Days After Shipment - Unit 1	10%	4.2857%	4.2857%	
Nov. '99		4.2857%	4.2857%	~~4.2857%~~
Dec. '99		4.2857%	4.2857%	~~4.2857%~~
Jan. '00		4.2857%	4.2857%	4.2857%
Feb. '00		4.2857%	4.2857%	4.2857%
Mar. '00 CT Shipment - Unit 2		10%	4.2857%	4.2857%
Apr. '00 30 Days After Shipment - Unit 2		10%	4.2857%	4.2857%
May '00 CT Shipment - Unit 3			10%	4.2857%
June '00 30 Days After Shipment - Unit 3			10%	4.2857%
July '00				4.2857%
Aug. '00				4.2857%
Sept. '00				4.2857%
Oct. '00				4.2857%
Nov. '00				4.2857%
Dec. '00				4.2857%
Jan. '01 ~~CT Shipment – Unit 4~~				~~10.00~~ 4.2857%
Feb. '01 ~~30 Days After Shipment – Unit 4~~				~~10.00~~ 4.2857%
Mar. '01 CT Shipment – Unit 4				10.00%
Apr. '01 30 Days After Shipment – Unit 4				10.00%
Successful Completion of Performance Tests - Each Unit	10%	10%	10%	10%

Payment Terms are Net 3 Days with wire transfer

Late Fee - 0.5% per day for days 3-15.

Or 1% per month thereafter

6. LONG TERM COMBUSTION TURBINE SERVICE AGREEMENT

If the Owner selects to enter into a Long Term Combustion Turbine Service Agreement with the Contractor, the terms and conditions of the agreement will be negotiated in a separate negotiation session after the award.

7. TURBINE ALLIANCE

7.1. The Turbine Alliance will be negotiated at the time the Owner decides to enter into this type of agreement.

7.2. Any existing long term service agreements for the combustion turbine(s) included in this specification would become part of this turbine alliance agreement.

7.3. Owner reserves the right to start negotiations within a two year date from the award of the Combustion Turbine purchase.

General Electric Company
(Bidder's Name)

Critical speeds	RPM	Mode
First critical	1060 / 1107	Lateral / Torsional
Second critical	1100 / 6098	Lateral / Torsional
Third critical	2250 / 7129	Lateral / Torsional
Fourth critical	2460	Lateral

Vibration amplitude, ips (bearing housings)	Turbine		Generator	
	Nominal	Startup	Nominal	Startup
Typical	.25			
Alarm	.5			
Trip	1.0			

Vibration amplitude, mils (shaft displacement)	Turbine		Generator	
	Nominal	Startup	Nominal	Startup
Typical	< 5 mils pk - pk			
Alarm	N/A			
Trip	N/A			

Combustion Turbine Unit Weights and Dimensions

Turbine engine weight, tons 189 GT Base

Auxiliary skids	Length		Width		Height		Weight
	ft	in.	ft	in.	ft	in.	tons
Name Water Wash	Mech	Outline					10
Lube Oil							34
PEECC							21
LCI							5
BAC							2
CO_2							4
Demister							2
Cooling Fan							5
Fuel Forward							6
DC Link Reactor							.75

General Electric Company
(Bidder's Name)

Shipping weight, entire unit, tons		
	Piece	Weight, tons
Heaviest piece handled during erection	Generator	540,000
Heaviest piece handled during major overhaul	Turbine Rotor	94,000
Overall dimensions, including enclosures		
Length, ft	See Mechanical	
Width, ft	Outline Drawing	
Height, ft		
Component Descriptions		
Starting system General description	See Proposal	
Maximum number of starts allowed in a 1 hour period at maximum design temperature	3	
Time required between start attempts	Must coast to < 15% speed	
Minimum time between controlled shutdown and subsequent start	Time to coast to firing speed	
Minimum time between unit trip and subsequent start attempt	Time to coast to firing speed	
Electric starting motor		
Manufacturer	N/A	
Model	N/A	
Voltage	N/A	
Horsepower	N/A	
Speed, rpm	N/A	
Service factor	N/A	

General Electric Company
(Bidder's Name)

Full load amperes N/A

Starting amperes N/A

Torque converter

Type N/A

Manufacturer N/A

Rating N/A

Static starting system

Manufacturer GE

Drive capacity, kVA See One Line

Transformer size, kVA/volts/phase One Line KVA/ volts/ phase

Mechanical Accessory Equipment

Compressor wash system	On-Line	Off-Line
Type	Skid Mounted	
Flow to combustion turbine, gpm	26	81
Water quality required	Per GEK 103623	
Type of detergent	Not applicable	
Quantity of detergent	Not applicable	
Duration of wash, min	As required	Approx. 60
Tank capacity, gal	2500	
Recommended cleaning frequency, operating hours	Environment	Dependent

Fire detection and protection

Fire protection system

Type CO_2

Number of releases allowed before recharge 2

Cross zone protection None

General Electric Company
(Bidder's Name)

Concentration maintained: 34%

Time maintained: 40 min

Multi Stage Inlet air filtration equipment

Manufacturer: Braden or Equal

Type: 2 Stage w/Coalesoer

Filter media material: Synthetic

Efficiency: Dust spot efficiency of 96%

Means of filter support: SS Frame

Typical number of hours of operation before replacement of filter: Pre filter 3 mos. Final filter 2 yrs.

Pressure drop for

Clean conditions, in. H_2O: 1.25"

End of media life, in. H_2O: Typical 1" pre filter 2.5 Final filter

Exhaust Stack height, ft.: 100

Motors	kW	Volts	Phase	Enclosure	Quantity
Starting motor	N/A				
Main lube oil pump	75	480	3	TEFC	2
Emergency lube oil pump (dc)	15	125	1	TEFC	1
Lube oil reservoir exhauster	6	480	3	TEFC	2
Other motors					
Seee One Line					

1.5.3 Supplemental Performance Data. The following three-page table, designated C.5, shall be reproduced by the bidder as required to define the requested information for the following ambient temperatures and coincident relative humidities:

Temperature/Relative Humidity Points:	20° F/60 percent
	59° F/60 percent
	95° F/60 percent

Numbering sequence of the tables shall be as follows:

Table No.	Fuel	Ambient Conditions
1.5-1	Natural gas	20° F/60 percent RH
1.5-2	Natural gas	59° F/60 percent RH
1.5-3	Natural gas	95° F/60 percent RH
1.5-4	Fuel Oil	20°F/60 percent RH
1.5-5	Fuel Oil	59°F/60 percent RH
1.5.6	Fuel Oil	95°F/60 percent RH

Minimum load shall be defined as the minimum load at which the base load NOx emission concentrations are maintained.

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 1

Ambient Temperature/
Relative Humidity: 20 °F/ 60 percent

Manufacturer: GE

Barometric Pressure: 14.69 psia

Model No./Combustor: PG 7241 FA

Natural Gas: LHV = 20675 Btu/lb Fuel Oil = ___Btu/lb

Combustion System Type: Dry Low NO_x

NO_x Control Level: 15

Power Factor: 0.90 pf

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	14900	46600	93200	139900	186500
Auxiliary power, kW	608	608	608	608	608
Gross heat rate, Btu/kWh (LHV)	35375	15650	11520	9950	9310
Exhaust flow, lb/h	2714x10^3	2725x10^3	2741x10^3	3025x10^3	3800x10^3
Exhaust Temp., °F	647	787	1017	1112	1081
Inlet guide vane position, degrees	54	54	54	60.4	88
Fuel flow, lb/h	25495	35274	51932	67327	83980
Water injection flow lb/h	----------	----------------	----------------	----------------	----------------
Nitrogen oxides, ppmvd at 15 percent O_2	69	93	94	15(KGS) 9 (BB)	15(KGS) 9 (BB)
Nitrogen oxides, lb/h as NO_2	137	266	401	84(KGS)	105 (KGS)
Carbon monoxide, ppmvd	102	102	699	15	15
Carbon monoxide, lb/h	261	259	1759	41	52
Sulfur dioxide, ppmw	0	0	0	0	0
Sulfur dioxide, lb/h	0	0	1	1	1
TSP, lb/h (non-condensables only)	9	9	9	9	9
PM10, lb/h (non-condensables only)	9	9	9	9	9
TSP, lbm/h (excluding H_2SO_4, including other condensables)	18	18	18	18	18
PM10, lbm/h (excluding H_2SO_4, Including other condensables)	18	18	18	18	18
H_2SO_4, lbm/h	0	0	0	0	0

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 1

Unburned hydrocarbon, ppmvw	128	25	182	7	7
Unburned hydrocarbon, lb/h	193	38	279	12	15
Volatile organic compounds, ppmvw	25.6	5	36.4	1.4	1.4
Volatile organic compounds, lb/h	38.6	7.6	55.8	2.4	3
Oxygen, vol %	17.54	16.11	13.85	12.57	12.54
Nitrogen, vol %	76.75	76.25	75.45	75	74.99
Carbon, vol %	1.59	2.25	3.3	3.89	3.9
Argon, vol %	.92	.91	.9	.89	.91
Water, vol %	3.21	4.49	6.5	7.65	7.67
Opacity, percent	5	5	5	5	5

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 2

Ambient Temperature/
Relative Humidity: 59 °F/ 60 percent

Barometric Pressure: 14.69 psia

Natural Gas: LHV = 20675 Btu/lb Fuel Oil = ______ Btu/lb

NO_x Control Level: 15

Power Factor: 0.90 pf

Manufacturer: GE

Model No./Combustor: PG 7241 FA

Combustion System Type: Dry Low NO_x

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	13900	43300	86600	129900	173200
Auxiliary power, kW	608	608	608	608	608
Gross heat rate, Btu/kWh (LHV)	36505	16080	11790	10120	9370
Exhaust flow, lb/h	$2570x10^3$	$2580x10^3$	$2595x10^3$	$2890x10^3$	$3542x10^3$
Exhaust Temp., °F	690	830	1060	1139	1116
Inlet guide vane position, degrees	54	54	54	61.8	88
Fuel flow, lb/h	24542	33678	49383	63584	78495
Water injection flow lb/h	-----	-----	-----	-----	-----
Nitrogen oxides, ppmvd at 15 percent O_2	67	59	89	15(KGS) 9 (BB)	15(KGS) 9 (BB)
Nitrogen oxides, lb/h as NO_2	127	161	361	79 (KGS)	99 (KGS)
Carbon monoxide, ppmvd	102	> 1000	647	15	15
Carbon monoxide, lb/h	246	2596	1533	39	48
Sulfur dioxide, ppmw	0	0	0	0	0
Sulfur dioxide, lb/h	0	0	1	1	1
TSP, lb/h (non-condensables only)	9	9	9	9	9
PM10, lb/h (non-condensables only)	9	9	9	9	9
TSP, lbm/h (excluding H_2SO_4, Including other condensables)	18	18	18	18	18
PM10, lbm/h (excluding H_2SO_4, Including other condensables)	18	18	18	18	18
H_2SO_4, lbm/h	0	0	0	0	0

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 2

Unburned hydrocarbon, ppmvw	103	479	145	7	7
Unburned hydrocarbon, lb/h	148	691	211	11	14
Volatile organic compounds, ppmvw	20.6	95.8	29	1.4	1.4
Volatile organic compounds, lb/h	29.6	138.2	42.2	2.2	2.8
Oxygen, vol %	17.34	15.92	13.68	12.51	12.38
Nitrogen, vol %	76.12	75.62	74.84	74.44	74.39
Carbon, vol %	1.6	2.26	3.3	3.84	3.9
Argon, vol %	.91	.91	.89	.9	.89
Water, vol %	4.03	5.29	7.29	8.32	8.44
Opacity, percent	5	5	5	5	5

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 3

Ambient Temperature/
Relative Humidity: 95 °F/ 60 percent

Barometric Pressure: 14.69 psia

Natural Gas: LHV = 20675 Btu/lb Fuel Oil = ______Btu/lb

NO_x Control Level: 15

Power Factor: 0.90 pf

Manufacturer: GE

Model No./Combustor: PG 7241 FA

Combustion System Type: Dry Low No_x

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	12000	37600	75200	112800	150400
Auxiliary power, kW	608	608	608	608	608
Gross heat rate, Btu/kWh (LHV)	40305	17360	12500	10690	9760
Exhaust flow, lb/h	$2429x10^3$	$2438x10^3$	$2452x10^3$	$2691x10^3$	$3253x10^3$
Exhaust Temp., °F	729	862	1078	1170	1144
Inlet guide vane position, degrees	54	54	54	61.6	88
Fuel flow, lb/h	23395	31570	45465	58321	70999
Water injection flow lb/h	-------	-------	--------	---------	-------
Nitrogen oxides, ppmvd at 15 percent O_2	53	45	65	15(KGS) 9 (BB)	15(KGS) 9 (BB)
Nitrogen oxides, lb/h as NO_2	97	115	243	73 (KGS)	89 (KGS)
Carbon monoxide, ppmvd	102	>1000	687	15	15
Carbon monoxide, lb/h	229	2129	1515	36	43
Sulfur dioxide, ppmw	0	0	0	0	0
Sulfur dioxide, lb/h	0	0	1	1	1
TSP, lb/h (non-condensables only)	9	9	9	9	9
PM10, lb/h (non-condensables only)	9	9	9	9	9
TSP, lbm/h (excluding H_2SO_4, Including other condensables)	18	18	18	18	18
PM10, lbm/h (excluding H_2SO_4, Including other condensables)	18	18	18	18	18
H_2SO_4, lbm/h	0	0	0	0	0

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 3

Unburned hydrocarbon, ppmvw	87	422	172	7	7
Unburned hydrocarbon, lb/h	118	581	239	11	13
Volatile organic compounds, ppmvw	17.4	84.4	34.4	1.4	1.4
Volatile organic compounds, lb/h	23.6	116.2	47.8	2.2	2.6
Oxygen, vol %	16.85	15.53	13.44	12.24	12.1
Nitrogen, vol %	74.33	73.88	73.17	72.76	72.71
Carbon, vol %	1.61	2.22	3.19	3.75	3.82
Argon, vol %	.89	.89	.87	.86	.87
Water, vol %	6.33	7.49	9.83	10.39	10.51
Opacity, percent	5	5	5	5	5

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 4

Ambient Temperature/
Relative Humidity: 20 °F/ 60 percent

Manufacturer: GE

Barometric Pressure: 14.69 psia

Model No./Combustor: PG 7241 FA

Natural Gas: LHV = ________ Btu/lb Fuel Oil = 18550 Btu/lb

Combustion System Type: Dry Low No_x

NO_x Control Level: 42

Power Factor: 0.90 pf

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	15200	47600	95200	142900	190500
Auxiliary power, kW	1542	1542	1542	1542	1542
Gross heat rate, Btu/kWh (LHV)	34960	15590	12030	10480	10000
Exhaust flow, lb/h	2717x10^3	2729x10^3	2806x10^3	3156x10^3	3947x10^3
Exhaust Temp., °F	655	803	995	1058	1045
Inlet guide vane position, degrees	54	54	54	61.1	88
Fuel flow, lb/h	28646	40005	61741	80733	102695
Water injection flow lb/h	0	0	54260	87910	125980
Nitrogen oxides, ppmvd at 15 percent O_2	72	112	42	42	42
Nitrogen oxides, lb/h as NO_2	148	333	196	259	332
Carbon monoxide, ppmvd	>1000	428	124	38	20
Carbon monoxide, lb/h	2242	1096	315	108	70
Sulfur dioxide, ppmw	5	6	9	11	11
Sulfur dioxide, lb/h	27	38	59	77	98
TSP, lb/h (non-condensables only)	17	17	17	17	17
PM10, lb/h (non-condensables only)	17	17	17	17	17
TSP, lbm/h (excluding H_2SO_4, Including other condensables)	37	38	40	42	44
PM10, lbm/h (excluding H_2SO_4, Including other condensables)	37	38	40	42	44
H_2SO_4, lbm/h	3	4	6	8	10

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 4

Unburned hydrocarbon, ppmvw	157	52	14	7	7
Unburned hydrocarbon, lb/h	235	78	22	13	16
Volatile organic compounds, ppmvw	78.5	26	7	3.5	3.5
Volatile organic compounds, lb/h	117.5	39	11	6.5	8
Oxygen, vol %	17.65	16.22	13.24	11.78	11.45
Nitrogen, vol %	77.16	76.83	73.86	72.53	71.99
Carbon, vol %	2.1	3.01	4.49	5.24	5.36
Argon, vol %	.93	.92	.88	.86	.86
Water, vol %	2.17	3.03	7.53	9.59	10.35
Opacity, percent	20	20	20	20	20

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 5

Ambient Temperature/
Relative Humidity: 59 °F/ 60 percent

Manufacturer: GE

Barometric Pressure: 14.69 psia

Model No./Combustor: PG 7241 FA

Natural Gas: LHV = ________ Btu/lb Fuel Oil = 18550 Btu/lb

Combustion System Type: Dry Low NO$_x$

NO$_x$ Control Level: 42

Power Factor: 0.90 pf

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	14600	45500	91000	136500	182000
Auxiliary power, kW	1542	1542	1542	1542	1542
Gross heat rate, Btu/kWh (LHV)	35280	15790	12200	10800	10010
Exhaust flow, lb/h	2573x10^3	2585x10^3	2658x10^3	2820x10^3	3683x10^3
Exhaust Temp., °F	700	852	1050	1191	1098
Inlet guide vane position, degrees	54	54	54	56.7	88
Fuel flow, lb/h	27768	38728	59849	79472	98210
Water injection flow lb/h	0	0	51810	89620	119690
Nitrogen oxides, ppmvd at 15 percent O_2	70	109	42	42	42
Nitrogen oxides, lb/h as NO_2	138	314	190	255	318
Carbon monoxide, ppmvd	> 1000	384	91	20	20
Carbon monoxide, lb/h	1910	925	217	49	65
Sulfur dioxide, ppmw	5	6	10	12	11
Sulfur dioxide, lb/h	26	37	57	75	93
TSP, lb/h (non-condensables only)	17	17	17	17	17
PM10, lb/h (non-condensables only)	17	17	17	17	17
TSP, lbm/h (excluding H_2SO_4, Including other condensables)	37	38	40	42	44
PM10, lbm/h (excluding H_2SO_4, Including other condensables)	37	38	40	42	44
H_2SO_4, lbm/h	3	4	6	8	10

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 5

Unburned hydrocarbon, ppmvw	134	44	12	7	7
Unburned hydrocarbon, lb/h	191	63	17	11	15
Volatile organic compounds, ppmvw	67	22	6	3.5	3.5
Volatile organic compounds, lb/h	95.5	31.5	8.5	5.5	7.5
Oxygen, vol %	17.43	15.97	12.94	10.71	11.09
Nitrogen, vol %	76.53	76.19	73.22	71.3	71.3
Carbon, vol %	2.13	3.06	4.58	5.74	5.48
Argon, vol %	.92	.92	.88	.85	.86
Water, vol %	2.99	3.87	8.39	11.41	11.28
Opacity, percent	20	20	20	20	20

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 6

Ambient Temperature/
Relative Humidity: 95 °F/ 60 percent

Manufacturer: GE

Barometric Pressure: 14.69 psia

Model No./Combustor: PG 7241 FA

Natural Gas: LHV = ________ Btu/lb Fuel Oil = 18550 Btu/lb

Combustion System Type: Dry Low NO$_x$

NO$_x$ Control Level: 42

Power Factor: 0.90 pf

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	12800	40000	80000	120100	160100
Auxiliary power, kW	1542	1542	1542	1542	1542
Gross heat rate, Btu/kWh (LHV)	38490	16900	12770	11150	10240
Exhaust flow, lb/h	2432x10^3	2443x10^3	2501x10^3	2681x10^3	3365x10^3
Exhaust Temp., °F	740	886	1084	1200	1133
Inlet guide vane position, degrees	54	54	54	58.3	88
Fuel flow, lb/h	26561	36442	55072	72189	88377
Water injection flow lb/h	0	0	38960	68390	93580
Nitrogen oxides, ppmvd at 15 percent O$_2$	55	84	42	42	42
Nitrogen oxides, lb/h as NO$_2$	104	228	175	231	286
Carbon monoxide, ppmvd	731	372	87	20	20
Carbon monoxide, lb/h	1649	835	193	47	59
Sulfur dioxide, ppmw	5	6	9	12	11
Sulfur dioxide, lb/h	25	35	52	69	84
TSP, lb/h (non-condensables only)	17	17	17	17	17
PM10, lb/h (non-condensables only)	17	17	17	17	17
TSP, lbm/h (excluding H$_2$SO$_4$, Including other condensables)	37	38	40	42	44
PM10, lbm/h (excluding H$_2$SO$_4$, Including other condensables)	37	38	40	42	44
H$_2$SO$_4$, lbm/h	3	4	6	8	10

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 6

Unburned hydrocarbon, ppmvw	119	42	11	7	7
Unburned hydrocarbon, lb/h	162	57	16	11	13
Volatile organic compounds, ppmvw	59.5	21	5.5	3.5	3.5
Volatile organic compounds, lb/h	81	28.5	8	5.5	6.5
Oxygen, vol %	16.93	15.55	12.8	10.91	10.97
Nitrogen, vol %	74.73	74.42	72.03	70.5	70.25
Carbon, vol %	2.14	3.02	4.45	5.46	5.37
Argon, vol %	.9	.89	.86	.83	.84
Water, vol %	5.3	6.12	9.86	12.3	12.57
Opacity, percent	20	20	20	20	20

***** WITH INLET BLEED HEATING *****

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	95.	95.	95.	95.	95.	95.	95.	95.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	150,500.	112,800.	75,200.	37,600.	160,100.	120,100.	80,100.	40,000.
Heat Rate (LHV)	Btu/kWh	9,760.	10,690.	12,940.	18,180.	10,240.	11,170.	13,270.	18,180.
Heat Cons. (LHV) X 10^6	Btu/h	1,468.9	1,205.8	973.1	683.6	1,639.4	1,341.5	1,062.9	727.2
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	149,890.	112,190.	74,590.	36,990.	158,560.	118,560.	78,560.	38,460.
Heat Rate (LHV) Net	Btu/kWh	9,800.	10,750.	13,050.	18,480.	10,340.	11,320.	13,530.	18,910.
Exhaust Flow X 10^3	lb/h	3254.	2691.	2265.	2064.	3365.	2693.	2318.	2089.
Exhaust Temp.	Deg F.	1144.	1170.	1200.	1043.	1133.	1200.	1200.	1053.
Exhaust Heat (LHV) X 10^6	Btu/h	901.9	776.4	679.4	527.2	936.0	810.4	701.1	540.4
Water Flow	lb/h	0.	0.	0.	0.	93,590.	69,010.	46,070.	19,720.
EMISSIONS									
NOx (KGS Unit)	ppmvd @ 15% O2	15.	15.	15.	58.	42.	42.	42.	42.
NOx AS NO2 (KGS Unit)	lb/h	89.	73.	58.	156.	286.	232.	182.	123.
NOx (BB Units)	ppmvd @ 15% O2	9.	9.	9.	58.	42.	42.	42.	42.
NOx AS NO2 (BB Units)	lb/h	54.	44.	35.	156.	286.	232.	182.	123.
CO	ppmvd	15.	15.	15.	61.	20.	20.	36.	254.
CO	lb/h	43.	36.	30.	115.	59.	47.	74.	480.
UHC	ppmvw	7.	7.	7.	28.	7.	7.	7.	21.
UHC	lb/h	13.	11.	9.	33.	13.	11.	9.	25.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.
EXHAUST ANALYSIS	% VOL.								
Argon		0.87	0.86	0.86	0.87	0.84	0.84	0.85	0.86
Nitrogen		72.71	72.76	72.89	73.50	70.25	70.48	71.33	73.01
Oxygen		12.10	12.24	12.64	14.42	10.97	10.92	11.83	14.06
Carbon Dioxide		3.82	3.75	3.57	2.74	5.37	5.45	4.99	3.78
Water		10.51	10.39	10.04	8.47	12.57	12.31	11.01	8.29

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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***** WITH INLET BLEED HEATING *****

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	59.	59.	59.	59.	59.	59.	59.	59.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	173,200.	129,900.	86,600.	43,300.	182,000.	136,500.	91,000.	45,500.
Heat Rate (LHV)	Btu/kWh	9,370.	10,120.	12,190.	16,820.	10,010.	10,830.	12,780.	17,070.
Heat Cons. (LHV) X 10^6	Btu/h	1,622.9	1,314.6	1,055.7	728.3	1,821.8	1,478.3	1,163.	776.7
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	172,590.	129,290.	85,990.	42,690.	180,460.	134,960.	89,460.	43,960.
Heat Rate (LHV) Net	Btu/kWh	9,400.	10,170.	12,280.	17,060.	10,100.	10,950.	13,000.	17,670.
Exhaust Flow X 10^3	lb/h	3542.	2890.	2397.	2182.	3683.	2827.	2406.	2215.
Exhaust Temp.	Deg F.	1116.	1139.	1184.	1013.	1098.	1194.	1200.	1013.
Exhaust Heat (LHV) X 10^6	Btu/h	973.0	823.2	720.4	551.1	1011.7	865.3	744.8	562.1
Water Flow	lb/h	0.	0.	0.	0.	119,700.	90,620.	61,970.	27,170.

EMISSIONS

NOx (KGS Unit)	ppmvd @ 15% O2	15.	15.	15.	77.	42.	42.	42.	42.
NOx AS NO2 (KGS Unit)	lb/h	99.	79.	63.	220.	318.	256.	199.	131.
NOx (BB Units)	ppmvd @ 15% O2	9.	9.	9.	77.	42.	42.	42.	42.
NOx AS NO2 (BB Units)	lb/h	60.	48.	38.	220.	318.	256.	199.	131.
CO	ppmvd	15.	15.	15.	65.	20.	20.	30.	254.
CO	lb/h	48.	39.	33.	131.	65.	50.	63.	514.
UHC	ppmvw	7.	7.	7.	30.	7.	7.	7.	23.
UHC	lb/h	14.	11.	9.	36.	15.	11.	9.	28.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.

EXHAUST ANALYSIS % VOL.

Argon	0.89	0.90	0.90	0.90	0.86	0.84	0.86	0.90
Nitrogen	74.39	74.44	74.55	75.23	71.30	71.26	72.20	74.38
Oxygen	12.38	12.51	12.85	14.80	11.09	10.69	11.62	14.35
Carbon Dioxide	3.90	3.84	3.69	2.78	5.48	5.75	5.28	3.83
Water	8.44	8.32	8.02	6.29	11.28	11.46	10.04	6.55

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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***** WITH INLET BLEED HEATING *****

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	20.	20.	20.	20.	20.	20.	20.	20.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	186,500.	139,900.	93,300.	46,600.	192,700.	144,500.	96,400.	48,200.
Heat Rate (LHV)	Btu/kWh	9,310.	9,950.	11,910.	16,280.	10,040.	10,840.	12,680.	16,690.
Heat Cons. (LHV) X 10^6	Btu/h	1,736.3	1,392.	1,111.2	758.6	1,934.7	1,566.4	1,222.4	804.5
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	185,890.	139,290.	92,690.	45,990.	191,160.	142,960.	94,860.	46,660.
Heat Rate (LHV) Net	Btu/kWh	9,340.	9,990.	11,990.	16,500.	10,120.	10,960.	12,890.	17,240.
Exhaust Flow X 10^3	lb/h	3801.	3025.	2486.	2297.	3914.	2925.	2439.	2332.
Exhaust Temp.	Deg F.	1081.	1112.	1160.	966.	1068.	1183.	1200.	962.
Exhaust Heat (LHV) X 10^6	Btu/h	1036.9	863.8	751.3	569.2	1074.8	913.4	777.8	578.7
Water Flow	lb/h	0.	0.	0.	0.	130,530.	100,950.	68,710.	28,730.

EMISSIONS

NOx (KGS Unit)	ppmvd @ 15% O2	15.	15.	15.	80.	42.	42.	42.	42.
NOx AS NO2 (KGS Unit)	lb/h	106.	84.	66.	238.	338.	271.	209.	136.
NOx (BB Units)	ppmvd @ 15% O2	9.	9.	9.	80.	42.	42.	42.	42.
NOx AS NO2 (BB Units)	lb/h	64.	51.	40.	238.	338.	271.	209.	136.
CO	ppmvd	15.	15.	15.	104.	20.	20.	26.	282.
CO	lb/h	52.	41.	34.	221.	69.	51.	57.	605.
UHC	ppmvw	7.	7.	7.	47.	7.	7.	7.	27.
UHC	lb/h	15.	12.	10.	60.	15.	12.	10.	35.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.

EXHAUST ANALYSIS % VOL.

Argon	0.91	0.89	0.89	0.90	0.86	0.84	0.86	0.91
Nitrogen	74.99	75.00	75.11	75.86	71.77	71.48	72.40	74.99
Oxygen	12.54	12.57	12.88	15.00	11.20	10.54	11.39	14.59
Carbon Dioxide	3.90	3.89	3.75	2.77	5.49	5.89	5.48	3.78
Water	7.67	7.65	7.37	5.48	10.69	11.25	9.87	5.74

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat r correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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1.5.4 General Data - Generator.

General Information

Number of main bearings, type, and design load
Two, Elliptical, 316 psi

Maximum allowable bearing temperature, °F
30 Degree F rise

Maximum allowable vibration for each bearing for continued operation, peak-to-peak, microns
3 mils pk-pk

Maximum allowable shaft deflection for continued operation, peak-to-peak, mils
N/A

Allowable frequency variation

Limited time ±hertz/total time
-5 / +3 /10 Min.

Continually ±hertz/total time
+ / -2 /Continuous

Critical speeds	RPM	Mode
First critical	1015 / 1549	Lateral / Torsional
Second critical	2058 / 4314	Lateral / Torsional
Third critical	4337	Lateral
Fourth critical		

Miscellaneous Equipment	Manufacturer	Type
Annunciators	Later	Later
Prefabricated cables		
Pressure Transducers		
Pressure switches		
Control relays		
Control switches		
Push buttons		
Selector switches		
Indicating lights		

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Motor starters		
Light fixtures		
Convenience outlets		
Valves	Later	Later
Thermo Couple	Later	Later

Auxiliary Power

Guaranteed total electric load during normal operation for auxiliaries furnished with generator, ac load, kW	608/1542 Not Guaranteed
Total electric load during peak operation, ac load, kW	608/1542 Not Guaranteed
Emergency dc electric load, kW	125 Not Guaranteed

Generator Unit Weights and Dimensions

Weight of generator without excitation system and external accessories, lb tons	540,000 lbs.
Excitation system weight, lb tons	
Assembled weight of generator stator winding water cooling unit complete (dry/operating), lb tons (if required)	540,000 /
Weight of generator rotor, lb tons	76,000 lbs.

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List of major generator assemblies for shipment

Piece	Weight, tons

Voltage regulator and excitation system cubicles

Length, in. See Mech. Outline

Depth, in. See Mech. Outline

Height, in. See Mech. Outline

Weight, lb 10,000

Overall dimensions, including enclosures

Length, ft See Mech. Outline

Width, ft See Mech. Outline

Height, ft See Mech. Outline

Continuous rating at maximum H_2 pressure, rated power factor, and specified cooling water temperature, and based on maximum turbine rating as specified in the turbine specification, MVA 203.8 MVA

Nominal rpm 3600

Nominal frequency, hertz 60 Hz

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Voltages at continuous operation and nominal frequency

Nominal voltage, kV 18

Maximum voltage, kV 18.9

Minimum voltage, kV 17.1

Generator rated power factor (leading/lagging) 0.9 /0.95

Generator reactance in per unit value based on generator continuous kVA rating and nominal frequency

	Estimated	Percent Tolerance Plus	Percent Tolerance Minus
Direct axis subtransient reactance (saturated at rated voltage) X"dv	0.144		

Short-time capability expressed in terms of $I_2{}^2 t$ 10

Short-circuit ratio at rated voltage and rated stator current 0.58

Continuous current unbalance expressed in terms of I_2, percent 8

Generator winding capacitance to ground, all phases tied together, mfd 1.086

Current transformers

Location Refer to Electrical One Line

Quantity

Ratio

Relaying accuracy

Metering accuracy

Thermal rating

Mechanical rating

Secondary resistance at 25° C

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Generator field voltage at maximum kVA output, volts	344	
Generator field current at maximum excitation, amperes	1644	
Generator moment of inertia, Newton-meter^2	83,898 lb/ft^2	
Calculated value of H constant, combined moment of inertia of turbine and generator	0.855869 KVA/KW - SEC	
Maximum temperature rise above 40° C (104° F) gas temperature		
Generator armature winding temperature rise, °C	60°	
Generator field winding temperature rise, °C	70	
Generator core and mechanical parts adjacent to the insulation temperature rise, °C	65	
Maximum temperature rise above ambient air temperature if 40° C (104° F)		
Rotating armature winding temperature rise, °C	N/A	
Rotating field winding temperature rise, °C	N/A	
Collector rings temperature rise, °C	85	
Telephone influence factor (IEEE Standard 115)	Balanced	Residual
Calculated	8.46	
Guaranteed	40	
Wave form deviation factor (IEEE Standard 115)		
Calculated	Later	
Guaranteed	0.1	

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Temperature detectors located at	Number	Type
Armature	9	RTD
Rotating exciter	N/A	
Generator cold gas	4	RTD
Generator hot gas	2	RTD

Cooling System

Generator cooling system	Hydrogen
Stator core cooling	Hydrogen
Stator winding cooling	Hydrogen
Rotor winding cooling	Hydrogen
Rotating exciter cooling	N/A
Collector cooling	Air

Generator calculated losses at continuous nameplate MVA, voltage, and frequency

Total iron loss, kW	806.0
Generator stator I^2R loss, kW	213.7
Generator rotor I^2R loss, kW	565.9
Generator stray load loss, kW	Included
Generator windage loss, kW	247.6
Total generator loss excluding bearings and excitation system, kW	1845.5
Static exciter losses, kW	55.6
Excitation transformer losses, kW	Included in above
Generator efficiency, percent	98.97
Generator friction loss in bearings, seals, and collector rings, kW	251.3

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Generator Coolers

Number of coolers	5
Number of sections per cooler	One
Generator kVA capability with one cooler section out of service, percent	100%
Cooling water required by each generator cooler	
Inlet temperature, °F	95
Maximum flow, gpm	420 (total 2100 for all coolers)
Cleanliness factor	0.0005
Heat duty at maximum load, Btu/h	6,255,138 (1833.2 KW)
Tube side (water side) head loss through coolers	
Head, ft	18.2
Flow, gpm	2100
Tube side (water side) design conditions	
Pressure, psig	125
Temperature, °F	95
Complete for hydrogen-cooled generators	
CO_2 required to purge generator H_2 system, scf	7,264
H_2 required to fill system to maximum H_2 pressure after purging, scf	8,382 for 30 psig
Guaranteed H_2 consumption in 24 hours, scf	500 for 30 psig
H_2 seal oil flow, gpm	15
H_2 seal oil pressure, psig	35 psig

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Stator Winding Cooling Water System (if offered)

Number of coolers	N/A
Generator kVA capability with one cooler section out of service, percent	N/A
Quantity of cooling water at design inlet water temperature, gpm	N/A
Tube side head loss through coolers	N/A ______ psi at ____ gpm
Tube side design conditions, psig/°F	N/A /
Heat duty at maximum load, Btu/h	N/A
Number of circulating pumps	N/A
Full- or half-capacity pumps	N/A
Stator cooling water demineralizer description	N/A

Excitation System

Excitation system description	
Excitation system control system	
Make and type of excitation system	
Make and type of voltage regulator	
Communication method to operator interface	
Description of operator interface equipment	
Rated output of excitation system, kW	
Rated voltage, volts dc	

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Rated current, amperes dc

Excitation system response ratio, p.u. minimum

Ceiling voltage, percent minimum

Does the excitation system meet the definition of high initial response as defined in IEEE Standard 421.1? ____Yes ____No

Rotating Exciter Cooling System (if required)

Number of coolers N/A

Generator kVA capability with one cooler out of service, percent N/A

Heat duty at maximum load, Btu/h N/A

Cooling water required by each exciter cooler, maximum gpm at 41° C N/A

Tube side (water side) pressure drop through the coolers N/A psi at ____ gpm

Tube side design conditions, psig/°F ____ / ____

Motors	kW	Volts	Phase	Enclosure	Quantity
Hydrogen seal oil backup pump (dc)					
Hydrogen seal oil pump (ac)					
Hydrogen seal oil vacuum pump					
Stator winding cooling system pumps	N/A				
Other motors					

Subsection 1.1 - GENERAL DESCRIPTION AND SCOPE OF THE WORK

1.1.1 GENERAL. This Subsection covers the general description, scope of the work, and supplementary requirements for equipment, materials, and services included under these specifications.

The equipment and materials covered by these specifications will be incorporated in the Owner's Kennedy Generating Station and Brandy Branch Generating Station which will include a one and three complete 150-180 MW(nominal) Combustion Turbine generating units, respectively, operating in simple cycle mode.

The Kennedy Generating Station site is located at 4215 Talleyrand Avenue in Jacksonville, Florida. The Brandy Branch Generating Station site is located 2 miles northeast of Baldwin, Florida, in Duval County.

1.1.2 WORK INCLUDED UNDER THESE SPECIFICATIONS. The work under these specifications shall include furnishing f.o.b. at the Kennedy Generating Station site the combustion turbine generator unit with accessory equipment, and providing miscellaneous materials and services complete as specified herein.

All equipment and materials required for a complete combustion turbine generator shall be furnished, except as specified otherwise in these specifications. The equipment and materials to be furnished shall include, but not necessarily be limited to, the following major items:

Combustion turbine and accessories.

Hydrogen-cooled or air-cooled generator and accessories.

Electrical accessory equipment, including the following:

- Transformers - Excitation and startup isolation units only.
- 480 volt motor control centers.
- DC motor starters.
- Low voltage power and lighting systems.
- Surge protection for ac and dc panelboards.
- Batteries.
- Battery chargers/eliminators.
- Intrusion alarm switches.
- Raceway.
- Conductors.
- Grounding systems internal to furnished equipment.

Mechanical accessory equipment and materials, including the following:

- Lube oil cooling unit.
- Fuel oil forwarding system.
- Dry type low NO_x combustion system.

Water injection NO_x control system.

On-line and Off-line compressor wash system.

Fire detection and protection system.

Expanded unit enclosures/sound attenuation.

Multi-stage inlet air filtration system.

Inlet air duct and intake silencers.

Inlet bleed heating (external piping by others).

Exhaust system including exhaust duct, expansion joints, and stack.

Insulation and lagging.

Access provisions, including platforms, ladders and stairs.

Combustion turbine generator control system including the following:

Local control panels.

Remote control and monitoring equipment interface provisions. (Owner supplied equipment)

Sequence-of-events recorder.

Operating and maintenance training.

The equipment will be tested by the Owner after erection to demonstrate its ability to operate under the conditions and fulfill the guarantees as set forth herein. If the tests indicate that the equipment fails to meet guaranteed performance, the Contractor shall make additional tests and modifications in accordance with the requirements specified in Subsection 2.1.

The Contractor shall provide drawings and other engineering data, manufacturer's field services, tools, instruction manuals, recommended spare parts list, and miscellaneous materials and services, and shall participate in design conferences, all as specified herein.

Equipment, materials, and accessories furnished shall be delivered to the Kennedy Generating Station site where they will be received, unloaded, stored, and erected under separate contract. Deficiencies shall be sufficient cause to reject equipment f.o.b. carrier. Unloading from carrier and storing will not constitute acceptance.

1.1.3 MISCELLANEOUS MATERIALS AND SERVICES. Miscellaneous materials and services not otherwise specifically called for shall be furnished by the Contractor in accordance with the following:

All nuts, bolts, gaskets, special fasteners, backing rings, etc., between components and equipment furnished under these specifications.

All piping integral to skid mounted equipment furnished under these specifications, except as otherwise specified. This includes all vents, drains, instrument piping, insulation, lagging, pipe supports and other piping work required for a complete unit. Single piping connection points shall be provided for each service near grade level at the edge of the skids or equipment area. This includes fuel, air drains or any other piping systems.

Structural steel bolting materials between equipment furnished under these specifications.

Coupling guards for all exposed shafts and couplings.

Leveling blocks, soleplates, thrust blocks, matching blocks, and shims.

Field office furnishings, supplies, telephone service, and equipment for the manufacturer's technical service representatives. Erection drawings, prints, information, instructions, and other data for use by the Owner's erection contractor.

Detailed storage requirements and lubrication requirements (including frequencies) for use by the Owner's erection contractor.

Turbine Maintenance Tools
- Guide pins (for removal or replacement of bearing caps, compressor casing and exhaust frame)
- Fuel nozzle wrenches
- Fuel nozzle test fixture
- Spark plug electrode tool
- Clearance tools
- Fuel nozzle staking tool
- Combustion liner tool
- Bearing and coupling disassembly fixture
- Turbine rotor lifting beam and guides (one for every four units)

Generator Maintenance Tools
- Rotor lifting slings
- Rotor removal equipment including shoes, pans, pulling devices
- Rotor jacking bolts

Erection Tools
- Trunnions for generator
    - On loan basis only
- Jacking bolts for generator
- Foundation/installation washer and shim packs

Erection tools shall remain the property of the Contractor and all shipping costs to and from the jobsite shall be at the Contractor's expense.

1.1.4 WORK NOT INCLUDED UNDER THESE SPECIFICATIONS. The following items of work will be furnished by the Owner:

Site preparation, grading and fencing.

Concrete embedded raceways.

Below grade grounding mat.

Receiving, unloading, storing, and field erection of all equipment.

Foundations, foundation bolts, bolt sleeves, and equipment bases.

Grouting materials and the placing thereof.

Cables (power and control) between skids and base mounted equipment.

Lubricants and fuels for operation.

Solvents and cleaning materials.

Piping and associated insulation and lagging between equipment skids and base mounted equipment.

Wiring and r

Finish painti

Operating p

1.1.5 CONTRACTO
be in accordance wi

1.1.5.1 Submittal of
to the design and su
so that the Kennedy

The Contractor will b
herein to assure con

The Contractor shall
engineering schedul

1.1.5.2 Manufacture
representatives, on a
hauling, storing, clea

The Contractor shall
require field inspecti
any needed changes
equipment has been
done before initial op

The manufacturer's t
operating personnel

1.1.5.3 Design Con
Engineer or Owner t
additional design co

1.1.5.4 Instruction M
these specifications

1.1.5.5 Recommend
with the Technical P
Combustion Turbine
portion of the Cost P

1. All spa

2. All spa
   includir

3. All spa
   inspect

4. All spa
   path in

ceway between equipment skids and base mounted equipment.

g of all equipment except as specified herein.

sonnel for startup and tests.

'S SERVICES. The services called for in WORK INCLUDED UNDER THESE SPECIFICATIONS shall the following.

ngineering Data. Drawings and other engineering data for the specified equipment and materials are essential sequent construction of the entire project. Time is a basic consideration in completing each phase of the work enerating Station Combustion Turbine can be in commercial operation on the specified date.

required to submit drawings and engineering data in accordance with the schedule and requirements specified liance with the overall construction and operating schedule.

llow a reasonable amount of time for mailing, processing, and Engineer's review of drawings and data in his and procurement/production/shipping schedule.

s Field Services. The Contractor shall furnish the services of one or more manufacturer's field service resident basis, to provide technical direction to the Owner's erection contractor for unloading from transport, ing, installing, startup, and testing of the equipment furnished under these specifications.

lso furnish the field services of direct representatives of the manufacturers of auxiliary equipment which may and adjustment to assure proper operation. They shall inspect the equipment after its installation and make or adjustments to assure proper operation. They shall furnish written certification to the Owner that the nspected and adjusted by them or under their supervision and that it is ready for service, all of which shall be ration of the equipment.

chnical field representatives shall be present during the startup of the equipment and shall instruct the its proper operation.

rence. The Contractor's design engineer shall attend a design conference at a time and place selected by the discuss matters relative to the execution of this Contract. The Contractor's design engineer shall attend erences as required by the Engineer or Owner thereafter to expedite the work.

anuals. Instruction manuals shall be furnished in accordance with the requirements stated in Subsection 1.3 of nd as scheduled herein.

d Spare Parts. The Contractor shall provide the following recommended spare parts list and associated costs oposal. The spare parts shall include those required for all on-base and off-base equipment furnished with the The costs for all spare parts required as part of the Service Agreement shall be included in Service Agreement oposal. The recommended spare parts lists shall be submitted in separate lists as follows:

parts and materials required through startup and testing.

parts and materials that are expected to require replacement over the period of operation from startup to and g the first combustion inspection.

parts and materials that are expected to require replacement over the period of operation from the combustion on to and including the hot gas path inspection.

parts and materials that are expected to require replacement over the period of operation from the hot gas ection to and including the first major overhaul.

The listing shall include the manufacturer of each part, a description of each part (including industry standard part number if available), the assembly or equipment in which each part will be used, and recommended quantities to be stocked; shall classify the relative criticality of parts based on the manufacturer's experience; and shall list the lead time required for manufacture and deliveryof each part.

The Owner will retain the option of purchasing any one or any combination of spare parts listed at the prices quoted until 6 months after the date of commercial operation.

1.1.6 MILL AND FACTORY WITNESS TESTS. Supplementing the provisions of Subsection 2.1 concerning mill and factory witness tests, the Contractor shall notify the Engineer and Owner prior to the date of each mill or factory witness test as scheduled under Schedule of Activities.

1.1.7 SCHEDULE. The time of completion of the work is a basic consideration of the contract. This shall include the completion of various activities in accordance with the milestone time periods and dates listed in addition to the timely delivery of the equipment and materials.

The Schedule of Activities included at the end of this article stipulates the milestone time periods and dates for the work included in this Contract. It is necessary that the Contractor perform the activities shown on or before the dates indicated to avoid delay of the entire project.

1.1.7.1 Activity Periods and Dates. The time periods and dates listed in the Schedule of Activities indicate the latest dates by which the listed activities shall be completed. Data, drawings, and lists for planning, engineering, and documentation may be submitted earlier than the indicated dates at the Contractor's option.

Equipment and materials shall be delivered within the time frame specified. The Owner will not be obligated to accept delivery or make payment for equipment delivered prior to the earliest acceptable delivery date.

1.1.7.2 Engineering Schedule. The Contractor shall submit a schedule for engineering associated with the equipment being provided. Such schedules shall be updated and submitted by the first of each month until completion of the engineering effort.

1.1.7.3 Procurement/Production/Shipping Schedule. The Contractor shall submit a detailed procurement/ production/shipping schedule for the equipment and materials not later than the date indicated; thereafter, the schedule shall be updated as directed by the Engineer or Owner, but at least every 30 days.

1.1.7.4 Schedule of Activities.

Activity	Time of Submittal
Contractor to participate in design conference	15 days after contract award
Contractor's Schedules: Engineering Schedules	Preliminary with Technical Proposal, certified 30 days after contract award
Procurement/Production/ Shipping Schedules	Preliminary with Technical Proposal, certified 30 days after contract award
Drawings to Engineer and Owner	Drawing schedule according to Attachment 6 and Subsection 2.6.6, Logic Diagrams; Drawing submittal process according to Subsection 1.3-8, DRAWINGS.
Motor Information Sheets (motors < 4160 volts)	26 weeks after DFM
Motor Information Sheets (4160 volt motors)	12 weeks after DFM
Cost breakdown information	30 days after contract award

Cash flow projection	30 days after contract award
Review copy ("similar to") of Instruction Manual(s)	90 days prior to shipment of equipment
Twelve copies of Instruction Manuals	3 months after shipment of equipment
Hazardous materials documentation and list of materials	16 weeks after DFM
Recommended spare parts list to Owner	14 days after contract award
Notice of preshipment inspection	5 working days, as a minimum, prior to shipment
Notice of mill or factory witness tests or performance tests	10 working days prior to tests
Cut sheets and O&M data on specific components	3 months after shipment
Erection / Installation drawings	2 copies to JEA office - C. Bond

Activity	Dates			
Delivery	Unit 1	Unit 2	Unit 3	Unit 4
Contractor to deliver equipment to jobsite				
Begin delivery of major equipment (not before unless acceptable to JEA)	June 1, 1999	November 1, 1999	January 1, 2000	~~October 1, 2000~~ December 1, 2000
Complete delivery of all equipment and materials necessary for installation and operation of the Unit	October 31, 1999	April 1, 2000	June 1, 2000	~~February 28, 2001~~ April 30, 2001
Operation of Unit	Unit 1	Unit 2	Unit 3	Unit 4
Estimated Date of Initial Operation of Unit	April 1, 2000	November 15, 2000	November 15, 2000	~~October 1, 2001~~ December 1, 2001
Date of Commercial Operation of Unit	May 1, 2000	December 15, 2000	December 15, 2000	~~November 1, 2001~~ January 1, 2002

ATTACHMENT 1

TECHNICAL DATA SHEETS

General Electric Company
(Bidder's Name)

1.5.1 Performance Data - Combustion Turbine Generators.

Performance Data at Specified Conditions (Reference Table 2.1-1)

Parameter	Condition A	Condition B
Guaranteed or expected	Guaranteed	Guaranteed
Gross generator output, kW	173,200	182,000
CTG auxiliary power, kW	608	1542
CTG heat consumption, LHV, MBtu/h	1622.9	1821.8
Net CTG output, kW*	172,590	180,460
Net CTG heat rate, LHV, Btu/kWh*	9400	10,100
Fuel flow, lbm/h	78,746	98210
Water injection flow, lbm/h	0	119,700
Turbine inlet temperature °F	Proprietary	Proprietary
Inlet airflow, lbm/h	3,423,600	3,423,600
Inlet air pressure drop, in. H_2O	3.04	3.04
Compressor inlet temperature, °F	59	59
Exhaust pressure drop, in. H_2O	5.5	5.5
Exhaust gas flow, lbm/h	3542×10^3	3683×10^3
NO_x emissions at 15 percent O_2, ppmvd* (KGS: Kennedy Generating Station / BB: Brandy Branch)	15 (KGS) / 9 (BB)	42
NO_x emissions at 15 percent O_2, lbm/h*	99 (KGS) / 60 (BB)	318
CO emissions ppmvd*	15	20
CO emissions lbm/h*	48	65
UHC emissions, ppmvw*	7	7
UHC emissions, lbm/h*	14	15
VOC emissions, ppmvw*	1.4	3.5
VOC emissions, lbm/h*	2.8	7.5

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TSP, lbm/h*(non-condensables only)	9	17
PM10, lbm/h*(non-condensables only)	9	17
TSP, lbm/h*(excluding H_2SO_4, Including other condensables)	19	46
PM10, lbm/h*(excluding H_2SO_4, Including other condensables)	19	46
Opacity, percent*	5	20
SO_2, ppmvw, lbm/h*	0.0	93
H_2SO_4, lbm/h*		

Note: The basis for each load condition is specified in the Technical Requirements, Subsection 2.1, Performance Criteria. Items marked with an asterisk (*) shall be guaranteed for all load conditions designated "Guaranteed," in accordance with Subsection 2.1.

<u>Auxiliary Power Requirements</u>

	Included in Net Output, kW	Total Connected Power, kW
Turbine cooling air compressor	112	112
Control air compressor	--------------	-------------
Space heaters	20	90
Lube oil pumps (ac)	75	150
Lube oil pumps (dc)	----------------	15
Lube oil cooler fans	120	120
Cooling water pumps	112	225
Generator cooling system	------------------	------------------
Rotor turning motor	------------------	6
H_2 seal oil pump	8	8
Power oil pump	15	30
Vapor extractor	-------------------	------------------
Mist eliminator	6	12
Control system	50	50
Air conditioners	50	100
Ventilation fans/blowers	40	70

General Electric Company
(Bidder's Name)

Other (ac) AA comp	373	746
Other (ac) Dnt. Fuel Htr		225
Other (ac) Fuel Feed Pump	38	76
Other Liquid Fuel Pump	300	300
Other ~~(dc)~~ Water Injection Pump	223	223
Total at continuous baseload	608 gas 1542 dist	
Total standby (turning gear operation) power	736	

Note: Auxiliary power data shall be for steady-state operation at the guaranteed load condition.

Startup and Shutdown Performance

Estimated ~~Guaranteed~~ normal cycle starting time from cold standby to synchronization and continuous baseload, min ~~Later~~13 minutes / 25 minutes

Estimated ~~Guaranteed~~ fast cycle starting time from cold standby to synchronization and continuous baseload, min. ~~Later~~13 minutes / 17 minutes

Estimated ~~Guaranteed~~ rate of load change, ~~kW~~%/min ~~Later~~ 8.33%/min (normal) / 25%/min (fast)

Total gross generation per start

Normal start, kWh Later

Fast start, kWh Later

Total auxiliary power required per start

Normal start, kWh Later

Fast start, kWh Later

Peak auxiliary power required per start, kW Later

Fuel consumed per start (LHV)

Normal start, Btu Later

Fast start, Btu Later

General Electric Company
(Bidder's Name)

Noise Emissions	Turbine	Generator
Guaranteed average near field noise levels at 3 feet from the combustion turbine generator and any associated auxiliary equipment, operating at full load, dBA to a reference of 20 micropascals	85	
Guaranteed far field noise levels at 400 feet from the combustion	dBA	dBC
turbine enclosure boundary, operating at full load	65	75

Reference band levels

Reference Only Octave band center frequency, hertz	*Octave band levels* *Not guaranteed. For reference only.*
31	76
63	72
125	68
250	63
500	60
1,000	58
2,000	58
4,000	54
8,000	50

Operational Performance

Maintenance intervals

Combustion inspection	8000
Hot gas path	24,000
Major overhaul	48,000

General Electric Company
(Bidder's Name)

Expected degradation data	Fired Hours of Operation 1,000	4,000	8,000	16,000	24,000
Nonrecoverable degradation in baseload output, percent	See	Curve	In	Proposal	
Nonrecoverable degradation in baseload heat rate, percent	See	Curve	In	Proposal	

Miscellaneous

Bidder's definition of baseload	Unit Operating at Nominal Firing Temp
Bidder's definition of peak load	Not Applicable For This Equipment
Is a factory fired operation test completed for the unit proposed (Yes or No)	Yes
If yes, provide details	See Proposal

1.5.2 General Data - Combustion Turbine.

Manufacturer	GE	
Location assembled	Greenville, SC	
Combustion turbine model number	PG 7241 FA	
Gas delivery conditions		
Minimum required, psig, °F	400	
Maximum allowed, psig, °F	475	

General Design Information

Overspeed trip	
Electronic, rpm	3960
Mechanical bolt, rpm	N/A

Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

July 21, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. N. Bert Gianazza, P.E.
Jacksonville Electric Authority
21 West Church Street
Jacksonville, FL 32202-3139

Re: Second Request for Additional Information
DEP File No. 0310485-001-AC (PSD-FL-267)
Brandy Branch Facility - Three 170 MW Combustion Turbines

Dear Mr. Gianazza:

On June 22, 1999 the Department received your response to our letter of May 26 requesting additional information on the subject application. In order to continue processing your application, the Department will need the additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. JEA's response to the request for "specific information on what costs are required in order to obtain a guarantee of 9 ppm" indicated that a guarantee of 9 ppm had been obtained. However, "JEA understands that this guarantee is valid only for the new and clean test performed after installation of the unit" and a GE letter dated December 8, 1998 was attached, noting that an improved guarantee of 9 ppm was available. The referenced letter did not incorporate details about the 9 ppm guarantee, only that one was available. The Department requests more explicit information about the 9 ppm guarantee, specifically including JEA's request for the guarantee and GE's response to the request. Additionally, please provide information relative to the cost of securing that guarantee.

2. In previous discussions, JEA has indicated that the Brandy Branch facility would be "replacing" older generating units with higher emissions. The South Side plant has been mentioned in those discussions. Please provide the Department with data reflecting the most recent 2 years worth of fuel consumed at that facility. The data should also include average annual pollutant emissions and hours of operation by fuel type for each generating unit. Additionally, please provide JEA's specific plans for the South Side facility in the event that the Brandy Branch facility is approved.

3. The Department has remaining questions concerning the request to "re-examine the use of fuel oil as a back-up fuel" and the corresponding effects on the Class I Significant Impact Levels for SO_2.

    a) Please provide cost information for procuring oil with a sulfur specification less than 0.05% for this project and estimate its impact on the Class I Significant Impact Levels for SO_2.

    b) As per previous correspondence with the Department, please rerun the Class I increment analysis including the Putnam County sources and all (eleven) Okefenokee receptors.

c) Please review and comment on the necessity of the Brandy Branch facility to be permitted to combust oil at the maximum hourly throughput for 24 hours each day on all three CT's (up to the requested limit of 800 hours per year).

We have received written comments from the Air Quality Branch of the Fish and Wildlife Service and are enclosing them, as they comprise a part of this completeness review.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): "*The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application.*"

If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9530. Matters regarding review of the modeling should be directed to Chris Carlson (meteorologist) at 850/921-9537.

Sincerely,

7/21

A.A. Linero, P.E. Administrator
New Source Review Section

AAL/mph

cc: Gregg Worley, EPA
Mr. John Bunyak, NPS
James L. Manning, P.E. RESD
Chris Kirts, DEP-NED
Anthony L. Compaan, P.E., Black & Veatch

Z 333 618 113

US Postal Service

Receipt for Certified Mail

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PS Form **3800**, April 1995

Sent to Bert Gianazza	
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Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 7-21-99 0310465-001-AC P50-F1-267	

Fold at line over top of envelope to the right of the return address

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SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

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1. ☐ Addressee's Address
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Consult postmaster for fee.

3. Article Addressed to:

Mr. Bert Gianazza, PE
JEA
21 W. Church St.
Jacksonville, Fl
32202-3139

4a. Article Number
Z 333 618 113

4b. Service Type
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☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery 7-23-99

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6. Signature: *(Addressee or Agent)*
X

8. Addressee's Address *(Only if requested and fee is paid)*

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

Thank you for using Return Receipt Service.

Technical Review of Additional Information
for Jacksonville Electric Authority's Brandy Branch Generating Station
Baldwin, Florida
by
Air Quality Branch, Fish and Wildlife Service – Denver
July 20, 1999

Jacksonville Electric Authority (JEA) is proposing to install three 170 MW simple cycle combustion turbines at their Brandy Branch Facility. The turbines will fire natural gas as the primary fuel, with low sulfur (less than 0.05 %) fuel oil as a back-up fuel. The Brandy Branch Facility is located 34 km southeast of Okefenokee Wilderness and 127 km southwest of Wolf Island Wilderness, both Class I air quality areas administered by the U.S. Fish and Wildlife Service (FWS). The project will result in PSD-significant increases in emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), particulate matter (PM), fine particulate matter less than 10 microns in diameter (PM-10), carbon monoxide (CO), and sulfuric acid mist (SAM). Proposed emissions (in tons per year – TPY) are summarized below.

POLLUTANT	EMISSIONS INCREASE (TPY)
NO_X	858
SO_2	124
PM-10	75
CO	366
SAM	15.2

Air Quality Related Values (AQRV) Analysis

JEA performed a regional haze analysis for Wolf Island, concluding that the project would not contribute significantly to visibility impairment in the area. In December 1998, we advised JEA that they should also evaluate regional haze impacts in Okefenokee. Regional haze analyses are required of sources greater than 50 km from a receptor in a Class I area. Although the project was only 34 km from the nearest boundary of the Class I area, the project was more than 50 km from some receptors in the Class I area. (Okefenokee is approximately 55 km from south to north.)

An ISC analysis by JEA indicated that the project had the potential to significantly contribute to regional haze at Okefenokee. We advised the applicant that they had several options, including reducing production, accepting lower emissions limits, or performing a refined modeling analysis (CALPUFF-Lite or CALPUFF). In any case, they needed to demonstrate that the project's emissions would not significantly contribute to visibility impairment in the Class I area.

The applicant chose to do an analysis with CALPUFF-Lite (a screening version of CALPUFF) and submitted the results June 24, 1999. Although this model predicted impacts lower than impacts predicted with ISC, they were still significant. The change in visibility (light extinction) while burning gas was predicted to be 5.6%. The change in visibility (light extinction) while burning fuel oil was predicted to be 27.2%. FWS considers a change of greater than 5% to be significant and a potential adverse impact to the Class I area. At this time we reiterated JEA's options (see above). JEA stated its intention of doing a CALPUFF analysis, a refined version of CALPUFF-Lite.

On July 19, 1999, in a phone conversation with JEA, we learned that they had not yet started the CALPUFF analysis. However, JEA requested that the Florida Department of Environmental Protection issue an intent to permit the project on August 15. We advised JEA that, if they do not demonstrate by that time that the project's emissions would not significantly contribute to regional haze, we would object to the project. JEA agreed to start the CALPUFF analysis immediately. In addition, JEA agreed to accept as a permit condition the shut-down of their Southside Generating Station, 15 km south of Brandy Branch. JEA believes that the Southside shut-down would result in an emissions decrease that would more than offset new emission impacts from Brandy Branch. We stated our support of the shut-down, as it would result in a high-emitting facility being replaced by a more efficient and lower-emitting facility. We noted that such offsets should result in a net benefit to air quality at the Class I area, and that this should be demonstrated by modeling.

In summary, JEA needs to demonstrate to us that the proposed Brandy Branch project will not cause additional visibility impairment at Okefenokee Wilderness. JEA has a variety of options for doing this, including choosing not to proceed with the project, reducing the project's emissions, offsetting the project's emissions with the shut-down of Southside Station, and conducting a more refined modeling analysis. If refined modeling still predicts a significant contribution to visibility impairment from the project, FWS will consider the magnitude, duration, and frequency of impacts, and other factors in making an adverse impact determination.

Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

Florida
Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David Struhs
Secretary

FAX TRANSMITTAL SHEET

DATE: 29 JUNE 1999

TO: Kyle Lucas

PHONE: 913-458-9062 **FAX:** 913-458-2934

FROM: Cleve Holladay **PHONE:** 29 JUNE 1999

Division of Air Resources Management **FAX:** **850.922.6979**

RE:

CC:

Total number of pages including cover sheet: 5

Message

Please insert these Putnam County SO_2 sources into the PSD Class I inventory and rerun 5 years of meteorology. If there are predicted exceedances of the inventory in the Okefenokee WA show that Brandy Branch does not significantly contribute ~~of~~ to any predicted exceedance.

If there are any problems with this fax transmittal, please call the above phone number.

"Protect, Conserve, and Manage Florida's Environmental and Natural Resources"

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HISTORICAL
SOUTHSIDE K&S {OIL UNITS}

CHUCK
JIM
SANDY
MARK
KYLE

OIL

6 MCF/HR

8MCF TOTAL {5MCF/HR BB + 3MCF/HR JAY

GAS - N. side

HISTORICAL OIL OPERATION

.05% ↓ .5% ↓

40MCF/DAY

4000 HRS/YR 2001
3000 2002

2000 2005-
↓

James 3:30 - 4:00 222-6853

Florida Pest

5 years of CALPUFF

apply at 50 km —

1 year of met data

Colorado Ammonia

PDF

No MORE ISC

Colorado Guidance

SAMSON CD Met Data

Mixing Height from SCRAM Bulletin Board

ISC Wet Deposition

52

PSD CLASS I INCREMENT

OTHER PUTNAM COUNTY SOURCES

APIS Number	Facility	Units	ISCST3 ID Name	Stack Parameters Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate (g/s)	(EXP/CON)
31JAX540025	Seminole Power Plant	Units 1 and 2	SEMELECT	205.7	10.97	326.5	7.99	2168.80	CON
31JAX540014	Florida Power & Light - Putnam	4x70Mw CT/HRSG + DB	FPLPUTNM	22.3	3.15	437.4	58.60	351.69	CON[a]
31JAX540016	Florida Power & Light - Palatka	Unit 2	FPLPALAT	45.7	3.96	408.1	9.50	-257.03	EXP

ISCST3 INPUT FILE

PAGE 1 of 2

```
SO STARTING
** Source Location Cards:      G-P FUTURE
**      SRCID SRCTYP       XS          YS          ZS
SO LOCATION  TRS     POINT      434000.   3283400.      .0
SO LOCATION  RB4     POINT      434000.   3283400.      .0
SO LOCATION  SDT4    POINT      434000.   3283400.      .0
SO LOCATION  LK4     POINT      434000.   3283400.      .0
SO LOCATION  PB4     POINT      434000.   3283400.      .0
SO LOCATION  PB5     POINT      434000.   3283400.      .0
SO LOCATION  CB4     POINT      434000.   3283400.      .0
SO LOCATION  PB6     POINT      434000.   3283400.      .0


** G-P 1974 BASELINE
SO LOCATION  RB1B    POINT      434000.   3283400.      .0
SO LOCATION  RB2B    POINT      434000.   3283400.      .0
SO LOCATION  RB3B    POINT      434000.   3283400.      .0
SO LOCATION  RB4B    POINT      434000.   3283400.      .0
SO LOCATION  SDT1B   POINT      434000.   3283400.      .0
SO LOCATION  SDT2B   POINT      434000.   3283400.      .0
SO LOCATION  SDT3B   POINT      434000.   3283400.      .0
SO LOCATION  SDT4B   POINT      434000.   3283400.      .0
SO LOCATION  LK1B    POINT      434000.   3283400.      .0
SO LOCATION  LK2B    POINT      434000.   3283400.      .0
SO LOCATION  LK3B    POINT      434000.   3283400.      .0
SO LOCATION  LK4B    POINT      434000.   3283400.      .0
SO LOCATION  PB4B    POINT      434000.   3283400.      .0
SO LOCATION  PB5B    POINT      434000.   3283400.      .0
SO LOCATION  CB4B    POINT      434000.   3283400.      .0


** PUTNAM CO. SOURCES
SO LOCATION SEMELECT  POINT     438800    3289200       .0
SO LOCATION FPLPUTNM  POINT     443300.   3277600.      .0
SO LOCATION FPLPALAT  POINT     442800.   3277600.      .0


** Source Parameter Cards:
** POINT:  SRCID     QS       HS       TS        VS       DS

SO SRCPARAM  TRS     75.60    76.2    533.2    32.03    0.94
SO SRCPARAM  RB4     13.85    70.1    477.6    19.42    3.66
SO SRCPARAM  SDT4     1.00    62.8    344.3     6.46    1.52
SO SRCPARAM  LK4      1.37    39.9    338.7    18.53    1.35
SO SRCPARAM  PB4     45.23    61.0    474.8    21.82    1.22
SO SRCPARAM  PB5    197.13    70.7    502.6    18.47    2.74
SO SRCPARAM  CB4    145.03    72.2    499.8    21.88    2.44
SO SRCPARAM  PB6      1.40    18.3    622.0    17.43    1.83


** G-P 1974 BASELINE
SO SRCPARAM  RB1B    -6.21    76.2    360.0     8.80    3.66
SO SRCPARAM  RB2B    -8.88    76.2    372.0     8.80    3.66
SO SRCPARAM  RB3B    -8.58    40.5    372.0     7.28    3.41
SO SRCPARAM  RB4B   -34.97    70.1    474.0    16.86    3.66
SO SRCPARAM  SDT1B   -0.13    30.5    366.0     7.53    0.76
```

ISCST3 INPUT FILE

PAGE 2 of 2

```
SO SRCPARAM  SDT2B    -0.18     30.5    375.0    9.51    0.91
SO SRCPARAM  SDT3B    -0.18     33.2    369.0    3.57    0.76
SO SRCPARAM  SDT4B    -0.71     62.8    346.0    8.26    1.52
SO SRCPARAM  LK1B    -0.24     15.2    401.0    5.24    1.28
SO SRCPARAM  LK2B    -0.24     15.9    341.0    10.67    1.71
SO SRCPARAM  LK3B    -0.48     15.9    342.0    8.47    1.71
SO SRCPARAM  LK4B    -1.40     45.4    351.0    16.46    1.31
SO SRCPARAM  PB4B   -45.22     37.2    477.0    14.54    1.22
SO SRCPARAM  PB5B  -161.15     72.9    520.0    15.97    2.74
SO SRCPARAM  CB4B  -121.28     72.9    477.0    10.52    3.05

** PUTNAM CO SOURCES
SO SRCPARAM SEMELECT  2168.8     205.7  326.5   7.99   10.97
** 2 OF FPL PUTNAM'S 4 CTS CONSUME PSD INCREMENT
SO SRCPARAM FPLPUTNM  175.85      22.3  437.4   58.60   3.15
SO SRCPARAM FPLPALAT  -257.03     45.7  408.1   9.50   3.96
```

PSD CLASS I INCREMENT PAGE 1of2

Table 2-2. Maximum Baseline Emissions Used in the Modeling Analysis for Georgia-Pacific, Palatka

Emission Unit	Unit ID	SO_2 (1974)	
		Short-Term Emissions	
		(lb/hr)	(g/s)
No. 1 Recovery Boiler	RB1	49.3	6.21
No. 2 Recovery Boiler	RB2	70.5	8.88
No. 3 Recovery Boiler	RB3	68.1	8.58
No. 4 Recovery Boiler	RB4	277.5	34.97
No. 1 Smelt Dissolving Tank	SDT1	1.0	0.13
No. 2 Smelt Dissolving Tank	SDT2	1.4	0.18
No. 3 Smelt Dissolving Tank	SDT3	1.4	0.18
No. 4 Smelt Dissolving Tank	SDT4	5.6	0.71
No. 1 Lime Kiln	LK1	1.9	0.24
No. 2 Lime Kiln	LK2	1.9	0.24
No. 3 Lime Kiln	LK3	3.8	0.48
No. 4 Lime Kiln	LK4	11.1	1.40
No. 4 Power Boiler	PB4	358.9	45.22
No. 5 Power Boiler	PB5	1,279.0	161.15
No. 4 Combination Boiler	CB4	962.5	121.28
TOTALS		3,093.9	389.83

Table 2-1. Maximum Future Emissions Used in the Modeling Analysis for Georgia-Pacific, Palatka

Emission Unit	Unit ID	SO_2	
		(lb/hr)	(g/s
New Bleach Plant	BLCH	--	--
TRS Incinerator	TRS	600.0	75.60
No. 4 Recovery Boiler	RB4	109.9	13.85
No. 4 Smelt Dissolving Tank	SDT4	7.9	1.00
No. 4 Lime Kiln	LK4	10.9	1.37
No. 4 Power Boiler	PB4	359.0	45.23
No. 5 Power Boiler	PB5	1,564.5	197.13
No. 6 Power Boiler	PB6	11.1	1.40
No. 4 Combination Boiler	CB4	1,151.0	145.03
TOTALS		3,814.3	480.6

Table 1

ISCST3 Model Predicted Maximum Concentrations of SO_2 for the 24-Hour Period and Applicable Loads at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I SIL
One Turbine	24-Hour	100	1984	0.14	0.20
		75		0.12	0.20
		50		0.11	0.20
		100	1985	0.09	0.20
		75		0.08	0.20
		50		0.07	0.20
		100	1986	0.11	0.20
		75		0.10	0.20
		50		0.09	0.20
		100	1987	0.12	0.20
		75		0.11	0.20
		50		0.09	0.20
		100	1988	0.11	0.20
		75		0.12	0.20
		50		0.11	0.20
Two Turbines		100	1984	**0.28**	0.20
		75		**0.25**	0.20
		50		**0.21**	0.20
		100	1985	0.18	0.20
		75		0.16	0.20
		50		0.14	0.20
		100	1986	**0.22**	0.20
		75		**0.21**	0.20
		50		0.18	0.20
		100	1987	**0.24**	0.20
		75		**0.21**	0.20
		50		0.18	0.20
		100	1988	**0.22**	0.20
		75		**0.24**	0.20
		50		**0.22**	0.20
Three Turbines		100	1984	**0.42**	0.20
		75		**0.38**	0.20
		50		**0.32**	0.20
		100	1985	**0.28**	0.20
		75		**0.24**	0.20
		50		**0.21**	0.20
		100	1986	**0.33**	0.20
		75		**0.31**	0.20
		50		**0.28**	0.20
		100	1987	**0.36**	0.20
		75		**0.32**	0.20
		50		**0.27**	0.20
		100	1988	**0.34**	0.20
		75		**0.36**	0.20
		50		**0.32**	0.20

NOTE: Maximum Predicted Concentrations represent high first high impacts.

Table 2

ISCST3 Model Predicted Maximum Concentrations of SO_2 for the 24-Hour Period and Applicable Loads at Wolf Island

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m^3)	Class I SIL
One Turbine	24-Hour	100	1984	0.07	0.20
		75		0.07	0.20
		50		0.06	0.20
		100	1985	0.04	0.20
		75		0.04	0.20
		50		0.03	0.20
		100	1986	0.04	0.20
		75		0.03	0.20
		50		0.03	0.20
		100	1987	0.04	0.20
		75		0.04	0.20
		50		0.04	0.20
		100	1988	0.04	0.20
		75		0.03	0.20
		50		0.03	0.20
Two Turbines		100	1984	0.15	0.20
		75		0.13	0.20
		50		0.11	0.20
		100	1985	0.09	0.20
		75		0.08	0.20
		50		0.06	0.20
		100	1986	0.07	0.20
		75		0.06	0.20
		50		0.06	0.20
		100	1987	0.08	0.20
		75		0.07	0.20
		50		0.08	0.20
		100	1988	0.08	0.20
		75		0.07	0.20
		50		0.06	0.20
Three Turbines		100	1984	**0.22**	0.20
		75		**0.20**	0.20
		50		0.17	0.20
		100	1985	0.13	0.20
		75		0.11	0.20
		50		0.09	0.20
		100	1986	0.11	0.20
		75		0.10	0.20
		50		0.08	0.20
		100	1987	0.12	0.20
		75		0.11	0.20
		50		0.12	0.20
		100	1988	0.12	0.20
		75		0.10	0.20
		50		0.08	0.20

NOTE: Maximum Predicted Concentrations represent high first high impacts.

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 23-Jun-1999 11:06am
From: Mike Halpin TAL
HALPIN_M
Dept: Air Resources Management
Tel No: 850/488-0114

To: Alvaro Linero TAL (LINERO_A)
CC: Teresa Heron TAL (HERON_T)

Subject: Re: Bert's memo on JEA Brandy Branch

Al -

Concerning Bert's memo below, I would make 3 points:

1) Bert states that GE will only guarantee 9 ppm after the initial test if they (GE) operate the units (which he says is not possible in JEA's case), and therefore JEA could not get a number for guaranteeing the 9 ppm into the future. CT maintenance and operation isn't a secret. It stands to reason that if GE CAN make a 9 ppm guarantee (if GE does the operation and maintenance), yet JEA CANNOT make that guarantee (if JEA does it), that either JEA does not have some measure of competency that GE does, or that JEA does not believe that GE can really do it. I find both possibilities to be poor enough to require a 9 ppm limit and let JEA figure it out; if they are unable to make it, they'll have to get GE in. I additionally do not find JEA's rationale for it being "impossible" to get GE to do their maintenance and operation as adequate reason to give JEA a higher NOx limit than other utilities. I think that what Bert is really saying is that he doesn't think that is a permit condition which he can take back to his superiors. I would want to understand JEA's rationale much better and would insist that JEA provide us with the "GE-9ppm" price (be it possible or not for JEA to consider) before I relinquished on that point.
2) Bert says that "In speaking with Mike, he is not comfortable giving us a complete on our application without completing the haze and visibility modeling." This is true. However, I would be willing to call it complete [pending our review of their recent responses, and with the caveat mentioned in 1) above] with Bert's understanding that the intent (to issue or deny) would not be issued until a satisfactory haze analysis is completed. Since time clocks get in our way, I'd rather not do this.
3) I can probably go with you to JEA one day next week, but prefer to wait until the following week.

I've left the previous e-mails below.

Mike

Bert's e-mail

Since GE will only guarantee the 9 ppm after the initial test if they operate the units (which is not possible in our case), we could not get a number for guaranteeing the 9 ppm in the future. The cost of obtaining the initial 9 ppm guarantee in lieu of the originally specified 15 ppm was $300,000 per unit ($900,000 total).

Our response to your RAI should be in your office for your consideration. I'd like to try to set up a meeting in the next week or two with system planning, engineering and ya'll (that's the southern plural of "you") to discuss the NOx limits, hours on oil, schedule, modeling, and whatever else. What is your availability next week, and would you be amenable to coming here?

Our construction schedule calls for start of construction on 10/1. In speaking with Mike, he is not comfortable giving us a complete on our application without completing the haze and visibility modeling. If we have to do CALPUF modeling, that could take 4-6 weeks, and would cause a serious schedule problem if we have to wait for the 90 day clock after that. We should have the CALPUF lite results today or tomorrow, and we will forward that info to Ellen Porter for review, per conversation with her. If we do have to do the CALPUF modeling, Ellen said she would not object to our application being deemed complete and doing the modeling concurrently with the application processing (we may need to put something in writing to that effect), but you would have to make that call. The other option would be to stand ready to issue the permit immediately after the modeling is finished and cut the 90 day clock short by about 4-6 weeks, if that is a viable approach.

I will keep you informed of developments. If you want to talk, just use my beeper number (904-818-6247).

I understand your and Ellen's position with regard to having to adequately address all the issues related to this project, and appreciate everything you're doing to try keep our schedule from slipping. I just hope we can find a way to do everything we need to do and still have a permit by 10/1.

Talk to you soon. Tx, Bert

From: Alvaro Linero TAL
850/921-9532[SMTP:Alvaro.Linero@dep.state.fl.us]
Sent: Wednesday, June 23, 1999 1:26 AM
To: giannb@jea.com
Cc: Mike Halpin TAL
Subject: JEA Brandy Branch
Sensitivity: Confidential

Hey Bert. I checked my phone messages and got your call. I forgot to update the message to show that I'm out. I'm at AWMA. I tried to track down Mark Barreta so we could meet with the Park service rep that was out here, but Mark left before I could collar him.

If the project is "permittable" I'm sure that it will get an Intent before the permit becomes the critical path.

I already wrote up TEC at Polk Power Station but it has not yet been issued for similar reasons. However, the production of the package is not a problem. Quite often the write-up takes a while. This one won't since we have good templates based on the JEA Kennedy write-up, the TEC project, and the Oleander draft.

Remember we were going to get a few details on the cost of the "continuing guarantee?" Any chances we could see that stuff?

I suggested to Mike that we meet with you soon one way or the other.

Thanks. Al Linero.

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 23-Jun-1999 10:25am
From: Gianazza, N. Bert
GianNB@jea.com
Dept:
Tel No:

To: 'Alvaro Linero TAL 850/921-9532' (Alvaro.Linero@dep.state.fl.us)
CC: 'Mike Halpin' (Halpin_M@dep.state.fl.us)
CC: 'Bareta, Mark J.' (BaretaMJ@bv.com)

Subject: Re: JEA Brandy Branch

Since GE will only guarantee the 9 ppm after the initial test if they operate the units (which is not possible in our case), we could not get a number for guaranteeing the 9 ppm in the future. The cost of obtaining the initial 9 ppm guarantee in lieu of the originally specified 15 ppm was $300,000 per unit ($900,000 total).

Our response to your RAI should be in your office for your consideration. I'd like to try to set up a meeting in the next week or two with system planning, engineering and ya'll (that's the southern plural of "you") to discuss the NOx limits, hours on oil, schedule, modeling, and whatever else. What is your availability next week, and would you be amenable to coming here?

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I will keep you informed of developments. If you want to talk, just use my beeper number (904-818-6247).

I understand your and Ellen's position with regard to having to adequately address all the issues related to this project, and appreciate everything you're doing to try keep our schedule from slipping. I just hope we can find a way to do everything we need to do and still have a permit by 10/1.

Talk to you soon. Tx, Bert

From: Alvaro Linero TAL 850/921-9532[SMTP:Alvaro.Linero@dep.state.fl.us]
Sent: Wednesday, June 23, 1999 1:26 AM
To: giannb@jea.com
Cc: Mike Halpin TAL
Subject: JEA Brandy Branch
Sensitivity: Confidential

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Remember we were going to get a few details on the cost of the "continuing guarantee?" Any chances we could see that stuff?

I suggested to Mike that we meet with you soon one way or the other.

Thanks. Al Linero.

INTEROFFICE MEMORANDUM

Date: 23-Jun-1999 09:01am
From: Mike Halpin TAL
HALPIN_M
Dept: Air Resources Management
Tel No: 850/488-0114

To: Alvaro Linero TAL (LINERO_A)
CC: Teresa Heron TAL (HERON_T)

Subject: Re: JEA Brandy Branch

Al -

We received JEA's sufficiency response yesterday, and I am reviewing it. Although they did not provide anything representing "the cost of continuing guarantee", we did not clearly request that in writing; our request stated "Please provide specific information on what costs are required in order to obtain a guarantee of 9 ppm as was provided for in that [Oleander] application." JEA did state that they estimated the cost to be $900,000 and that they have obtained that guarantee, HOWEVER they indicate that this is a new and clean guarantee only. They did not provide documentation from GE.

Al - I know that you want to get this thing out quickly, but if it was my call I would require JEA to meet 9 ppm on a continuous basis (as we did with Oleander) and give them 1000 hours of oil. I believe that we could structure the gas portion of their permit like Oleander's (i.e. - an annual stack test at 9 ppm and a 24 hour block average on a lb/hr basis) as well as the oil portion of their permit (an annual oil throughput limit with a 12 month rolling average compliance method). If JEA didn't like it, they could protest. If you wish to pursue this, let me know, as I believe you said that you were planning to take this permit over? If you wish to pursue this approach, let me take a crack at drafting the permit and we'll take it with us when we go to meet with Bert.

Let me know. Oh - We also have not received their regional haze analysis yet.

Mike

21 West Church Street
Jacksonville, Florida 32202-3139

RECEIVED
JUN 22 1999
BUREAU OF
AIR REGULATION

JEA

June 21, 1999

A. A. Linero, P.E. Administrator
New Source Review Section
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

PSD-FI-267
0310485-001-AC

Dear Mr. Linero:

In response to your letter of May 26, 1999 requesting additional information on the Jacksonville Electric Authority's Brandy Branch Facility air construction permit application for three 170 MW simple cycle combustion turbines, we are providing the following information.

1. **Request**: As indicated in the application, a recent BACT determination of General Electric simple cycle CTs for the Oleander Project resulted in NO_X emissions of 9 ppm. Please provide specific information on what costs are required in order to obtain a guarantee of 9 ppm as was provided for in that application.

   Response: The additional cost to obtain a 9 ppm guarantee for the Brandy Branch CTs was estimated at approximately $900,000. JEA has recently obtained this guarantee for these CTs. Please note that JEA understands that this guarantee is valid only for the "new and clean" test performed immediately after installation of the unit (see letter from GE dated December 8, 1998, attached). Long-term emissions are not guaranteed by GE. A copy of the Technical Data Sheets showing the original 15 ppm NO_X emission rate and the revised 9 ppm NO_X emission rate is provided as an attachment to this response.

2. **Request**: If costs were incurred to obtain a guarantee of 12 ppm from a higher level (e.g. 15 ppm), please provide that information.

   Response: A guarantee of 12 ppm has not been provided by GE. As mentioned in the response to question 1 above, the current guarantee by GE is for no more than 9 ppm of NO_X emissions during the "new and clean" test only. The 12 ppm value proposed by JEA is believed to represent BACT for these CTs based on actual performance data available from the Fort St. Vrain station, where a GE Frame 7FA with DLN 2.6 combustors is currently operating. Based on actual CEM data from this facility, JEA believes this level of NO_X emissions is achievable on a long-term basis.

Simple-cycle CTs such as these are typically used to provide electricity to the grid in response to varying (peaking) electrical load demand. These CTs are generally cycled from a cold (off) condition to a low load or a base load condition several times a day. They may also cycle from low load to base load during an operating day in response to the demand placed on the grid. Because combustion and burner conditions experience more variation in operating conditions, they experience a greater variation in resulting NOx emissions compared to base-load units. In simple-cycle (peaking) service, the number of "starts" determines the frequency of maintenance inspections, especially of the combustion section, rather than overall operating hours as with a base-load unit. This reflects the stress that multiple starts has on the combustion section and affects combustor performance, resulting in slightly increased NO_X emissions.

CEMs data recently submitted to the FDEP in support of JEA's Kennedy Generating Station air construction permit for a similar CT indicates that NO_X emissions were greater than 9 ppm approximately 27 % of the time. A closer examination of the data reveals that while the CT can typically provide NO_X emissions less than 9 ppm, occasional hourly NO_X emissions can exceed that value. JEA believes a BACT of 12 ppm of NO_X emissions provides a minimal margin to ensure long-term compliance with this limitation.

3. **Request**: Please explain why the "inlet bleed" data sheets show NO_X emissions on gas at 15 ppmvd.

   Response: These are the original data sheets for the project's proposed CTs. As mentioned above, GE has recently provided a 9 ppm guarantee for the "new and clean" test. This is for NO_X emissions only, and represents the only change from the original data. NO_X emissions were ratioed from the 15 ppm value to a 12 ppm value for the purpose of this permit application.

4. **Request**: Please provide the rationale for the 15 ppmvd at 15 % O_2 limit proposed for CO as BACT for natural gas firing. The combustors typically achieve 12 ppm of CO.

Response: BACT for the proposed CTs is good combustion control and the advanced combustor design. The 15 ppmvd of CO emission rate was provided by GE, and is the currently guaranteed value. While short-term, intermittent emissions of CO may be ("typically") less than 15 ppm, because of the type of firing-duty the combustor is expected to see during the proposed operation of the facility (simple-cycle peaking operation), JEA believes the guaranteed CO emission rate of 15 ppmvd appropriate for this facility.

5. **Request**: Please explain why 26.00 ppm CO while firing fuel oil is shown as the "Requested Allowable Emissions and Units" within each CTs Section H. Most other documentation indicates 20 ppm.

   Response: This is actually a typographical error and should read 36 ppm. This value is based on the maximum expected CO emission rate during operation at 50 % of load and at a 95 F ambient temperature. The 20 ppm CO emission rate is expected at all loads greater than 50 % of load, where the greater combustor efficiency results in reduced CO emissions. Note that the expected operation of the facility will result in minimal hours at reduced load, but this is a requested operating scenario.

6. **Request**: Please submit overlays (isopleths) of the maximum ground-level concentrations of NO_X, PM/PM_{10}, CO, and SO_2 with respect to the residential communities up to 2 miles (3.2 kilometers) from the proposed site.

   Response: All modeled impacts within 2 miles of the proposed site were less than the applicable significant impact levels. Based on these results, FDEP indicated the requested isopleths were not necessary (telephone conversation with Chris Carlson at FDEP).

7. **Request**: Please provide a detailed map showing the location of all of the sources and fence-line receptors used in the air quality impact analysis. These source and receptor locations should be shown in UTM coordinates since the UTM coordinate system is used in the modeling. In addition send us diskettes containing all of the air quality impact analysis modeling output files.

   Response: Enclosed with this response please find the requested maps and figures. Diskettes containing the requested modeling analysis were previously submitted to the FDEP.

8. **Request**: How will fuel oil be delivered to the site, e.g. pipeline or trucks? If by truck, please estimate the average number of fuel deliveries.

   Response: Fuel oil will be delivered to the site by truck. The average number of truck deliveries expected, at the maximum permitted annual fuel-oil firing rate, is approximately 11 trucks per day. The average number of truck deliveries expected, based on the "expected" annual fuel-oil firing rate, is less than 1 truck per day.

9. **Request**: Please re-examine the use of fuel oil as a back-up fuel. Provide an evaluation of 0, 1 and 2 CTs simultaneously combusting fuel oil and the corresponding effects on the Class I Significant Impact Levels for SO_2.

   Response: Fuel oil firing was evaluated in the original project design, and is envisioned as a back-up fuel source only. In the event of a natural gas curtailment or in an event where natural gas is not readily available as the primary fuel, fuel oil may be used to fire the CTs. This is primarily a backup fuel only, and this method of operation is limited by the requested number of hours of firing on this fuel. This amount of fuel oil firing was also evaluated as part of the air dispersion modeling analysis required under the Prevention of Significant Deterioration (PSD) program. Worst-case fuel-oil firing from the three CTs operating simultaneously were modeled and shown to have an impact greater than the significant impact level in both of the Class I areas for the short-term averaging periods. Additional cumulative interactive-source modeling of these and other significant sources of SO_2 was performed based on data provided by FDEP, and was shown to have a cumulative impact less than the applicable Class I allowable increment for SO_2 for each applicable period. This operating scenario therefore provides acceptable modeled impacts.

   Tables 5-5 through 5-8 of the permit application provide the maximum short-term modeled SO_2 impacts for the Okefenokee and Wolf Island wilderness areas. Based on the maximum modeled short-term (3-hr) impact resulting from operating of the proposed facility only, it appears that in order to avoid triggering the above mentioned cumulative source modeling, only a single turbine could be operating on fuel oil at any given time. This clearly would be an unacceptable operating scenario for the proposed facility. In the event natural gas is not readily available, it may be necessary to fire all three CTs on fuel oil in order to provide needed electricity.

10. **Request**: Provide the worst-case start-up and shutdown emission characteristics for the units under consideration including start-up curves and duration of excess emissions. The Department plans to address excess emissions in its BACT determination.

    Response: A revised Table showing estimated emissions for NO_X and CO at low loads is provided as an attachment to this response. It is expected that emissions during start-up and shutdown would follow these estimated performance curves. A copy of the start-up and shutdown procedures previously submitted to FDEP as part of the response to a request for additional information for JEA's Kennedy CT air construction permit is included as an attachment to this response.

If you have any further questions on this permit applications, please do not hesitate to contact me at (904) 665-6247.

Sincerely,

N. Bert Gianazza, P.E.
Environmental Health & Safety Group

Enclosure[s]

cc: Mike Halpin, P.E., FDEP

CC: EPA
NPS
Duval Co.
NED

GE Energy Services

Marvin V. Sindel Jr.
Sales Manager

GE Energy Services Sales
General Electric International, Inc.
10 Van Dyck Rd. Jacksonville, FL 32218
*Tel: 904-757-2620, Dial Comm: 8*585-2620*
Fx: 904-757-2652
Email: marvin.sindel@ps.ge.com

12/8/98

Subject: GE Frame 7FA Gas Turbine NOx Guarantee for JEA

Mr. Jim Connolly, P.E.
JEA
21 West Church Street
Jacksonville, FL. 32202

Dear Jim,

Pursuant to your question on the NOx emission guarantee for the GE Frame 7FA units that JEA has purchased, the following information is offered:

1. The GE guarantee for the units purchased is 15 ppm NOx. GE will guarantee this level only for the "new and clean" test performed immediately after the installation of the unit is complete. This guarantee is similar to GE guaranteeing the performance of the unit at the "new and clean" condition.

2. The unit will operate at the 15 ppm level only for load conditions above 50% load. Should JEA use the units in their peaking mode for load control and operate the unit below this load point, the NOx level will exceed the 15 ppm .

3. The current NOx guarantee is for 15 ppm. However, with some additional modifications, GE is able to offer an improved guarantee of 9 ppm NOx. GE is working on providing an optional price to JEA to change the contractual guarantee to 9 ppm NOx.

I hope this answers your questions concerning the GE units contractual guarantee concerning NOx emissions. Should you have any further questions regarding the GE units, please contact me at your convenience.

Respectfully,

Marv Sindel

Marvin Sindel
Sales Manager

cc: J. Grassman - GE Schenectady

***** WITH INLET BLEED HEATING *****

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	95.	95.	95.	95.	95.	95.	95.	95.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	150,500.	112,800.	75,200.	37,600.	160,100.	120,100.	80,100.	40,000.
Heat Rate (LHV)	Btu/kWh	9,760.	10,690.	12,940.	18,180.	10,240.	11,170.	13,270.	18,180.
Heat Cons. (LHV) X 10^6	Btu/h	1,468.9	1,205.8	973.1	683.6	1,639.4	1,341.5	1,062.9	727.2
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	149,890.	112,190.	74,590.	36,990.	158,560.	118,560.	78,560.	38,460.
Heat Rate (LHV) Net	Btu/kWh	9,800.	10,750.	13,050.	18,480.	10,340.	11,320.	13,530.	18,910.
Exhaust Flow X 10^3	lb/h	3254.	2691.	2265.	2064.	3365.	2693.	2318.	2089.
Exhaust Temp.	Deg F.	1144.	1170.	1200.	1043.	1133.	1200.	1200.	1053.
Exhaust Heat (LHV) X 10^6	Btu/h	901.9	776.4	679.4	527.2	936.0	810.4	701.1	540.4
Water Flow	lb/h	0.	0.	0.	0.	93,590.	69,010.	46,070.	19,720.

EMISSIONS

NOx (KGS Unit)	ppmvd @ 15% O2	15.	15.	15.	58.	42.	42.	42.	42.
NOx AS NO2 (KGS Unit)	lb/h	89.	73.	58.	156.	286.	232.	182.	123.
NOx (BB Units)	ppmvd @ 15% O2	9.	9.	9.	58.	42.	42.	42.	42.
NOx AS NO2 (BB Units)	lb/h	54.	44.	35.	156.	286.	232.	182.	123.
CO	ppmvd	15.	15.	15.	61.	20.	20.	36.	254.
CO	lb/h	43.	36.	30.	115.	59.	47.	74.	480.
UHC	ppmvw	7.	7.	7.	28.	7.	7.	7.	21.
UHC	lb/h	13.	11.	9.	33.	13.	11.	9.	25.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.

EXHAUST ANALYSIS % VOL.

Argon	0.87	0.86	0.86	0.87	0.84	0.84	0.85	0.86
Nitrogen	72.71	72.76	72.89	73.50	70.25	70.48	71.33	73.01
Oxygen	12.10	12.24	12.64	14.42	10.97	10.92	11.83	14.06
Carbon Dioxide	3.82	3.75	3.57	2.74	5.37	5.45	4.99	3.78
Water	10.51	10.39	10.04	8.47	12.57	12.31	11.01	8.29

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

IPS- 70600 version code- 1 . 4 . 1 Opt: 10
ALMSTEJO 9/25/98 14:54 IBH 95F JEA.dat

***** WITH INLET BLEED HEATING *****

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	59.	59.	59.	59.	59.	59.	59.	59.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	173,200.	129,900.	86,600.	43,300.	182,000.	136,500.	91,000.	45,500.
Heat Rate (LHV)	Btu/kWh	9,370.	10,120.	12,190.	16,820.	10,010.	10,830.	12,780.	17,070.
Heat Cons. (LHV) X 10^6	Btu/h	1,622.9	1,314.6	1,055.7	728.3	1,821.8	1,478.3	1,163.	776.7
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	172,590.	129,290.	85,990.	42,690.	180,460.	134,960.	89,460.	43,960.
Heat Rate (LHV) Net	Btu/kWh	9,400.	10,170.	12,280.	17,060.	10,100.	10,950.	13,000.	17,670.
Exhaust Flow X 10^3	lb/h	3542.	2890.	2397.	2182.	3683.	2827.	2406.	2215.
Exhaust Temp.	Deg F.	1116.	1139.	1184.	1013.	1098.	1194.	1200.	1013.
Exhaust Heat (LHV) X 10^6	Btu/h	973.0	823.2	720.4	551.1	1011.7	865.3	744.8	562.1
Water Flow	lb/h	0.	0.	0.	0.	119,700.	90,620.	61,970.	27,170.

EMISSIONS

NOx (KGS Unit)	ppmvd @ 15% O2	15.	15.	15.	77.	42.	42.	42.	42.
NOx AS NO2 (KGS Unit)	lb/h	99.	79.	63.	220.	318.	256.	199.	131.
NOx (BB Units)	ppmvd @ 15% O2	9.	9.	9.	77.	42.	42.	42.	42.
NOx AS NO2 (BB Units)	lb/h	60.	48.	38.	220.	318.	256.	199.	131.
CO	ppmvd	15.	15.	15.	65.	20.	20.	30.	254.
CO	lb/h	48.	39.	33.	131.	65.	50.	63.	514.
UHC	ppmvw	7.	7.	7.	30.	7.	7.	7.	23.
UHC	lb/h	14.	11.	9.	36.	15.	11.	9.	28.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.

EXHAUST ANALYSIS % VOL.								
Argon	0.89	0.90	0.90	0.90	0.86	0.84	0.86	0.90
Nitrogen	74.39	74.44	74.55	75.23	71.30	71.26	72.20	74.38
Oxygen	12.38	12.51	12.85	14.80	11.09	10.69	11.62	14.35
Carbon Dioxide	3.90	3.84	3.69	2.78	5.48	5.75	5.28	3.83
Water	8.44	8.32	8.02	6.29	11.28	11.46	10.04	6.55

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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***** WITH INLET BLEED HEATING *****

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	20.	20.	20.	20.	20.	20.	20.	20.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	186,500.	139,900.	93,300.	46,600.	192,700.	144,500.	96,400.	48,200.
Heat Rate (LHV)	Btu/kWh	9,310.	9,950.	11,910.	16,280.	10,040.	10,840.	12,680.	16,690.
Heat Cons. (LHV) X 10^6	Btu/h	1,736.3	1,392.	1,111.2	758.6	1,934.7	1,566.4	1,222.4	804.5
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	185,890.	139,290.	92,690.	45,990.	191,160.	142,960.	94,860.	46,660.
Heat Rate (LHV) Net	Btu/kWh	9,340.	9,990.	11,990.	16,500.	10,120.	10,960.	12,890.	17,240.
Exhaust Flow X 10^3	lb/h	3801.	3025.	2486.	2297.	3914.	2925.	2439.	2332.
Exhaust Temp.	Deg F.	1081.	1112.	1160.	966.	1068.	1183.	1200.	962.
Exhaust Heat (LHV) X 10^6	Btu/h	1036.9	863.8	751.3	569.2	1074.8	913.4	777.8	578.7
Water Flow	lb/h	0.	0.	0.	0.	130,530.	100,950.	68,710.	28,730.

EMISSIONS

NOx (KGS Unit)	ppmvd @ 15% O2	15.	15.	15.	80.	42.	42.	42.	42.
NOx AS NO2 (KGS Unit)	lb/h	106.	84.	66.	238.	338.	271.	209.	136.
NOx (BB Units)	ppmvd @ 15% O2	9.	9.	9.	80.	42.	42.	42.	42.
NOx AS NO2 (BB Units)	lb/h	64.	51.	40.	238.	338.	271.	209.	136.
CO	ppmvd	15.	15.	15.	104.	20.	20.	26.	282.
CO	lb/h	52.	41.	34.	221.	69.	51.	57.	605.
UHC	ppmvw	7.	7.	7.	47.	7.	7.	7.	27.
UHC	lb/h	15.	12.	10.	60.	15.	12.	10.	35.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.

EXHAUST ANALYSIS % VOL.

Argon	0.91	0.89	0.89	0.90	0.86	0.84	0.86	0.91
Nitrogen	74.99	75.00	75.11	75.86	71.77	71.48	72.40	74.99
Oxygen	12.54	12.57	12.88	15.00	11.20	10.54	11.39	14.59
Carbon Dioxide	3.90	3.89	3.75	2.77	5.49	5.89	5.48	3.78
Water	7.67	7.65	7.37	5.48	10.69	11.25	9.87	5.74

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat ra correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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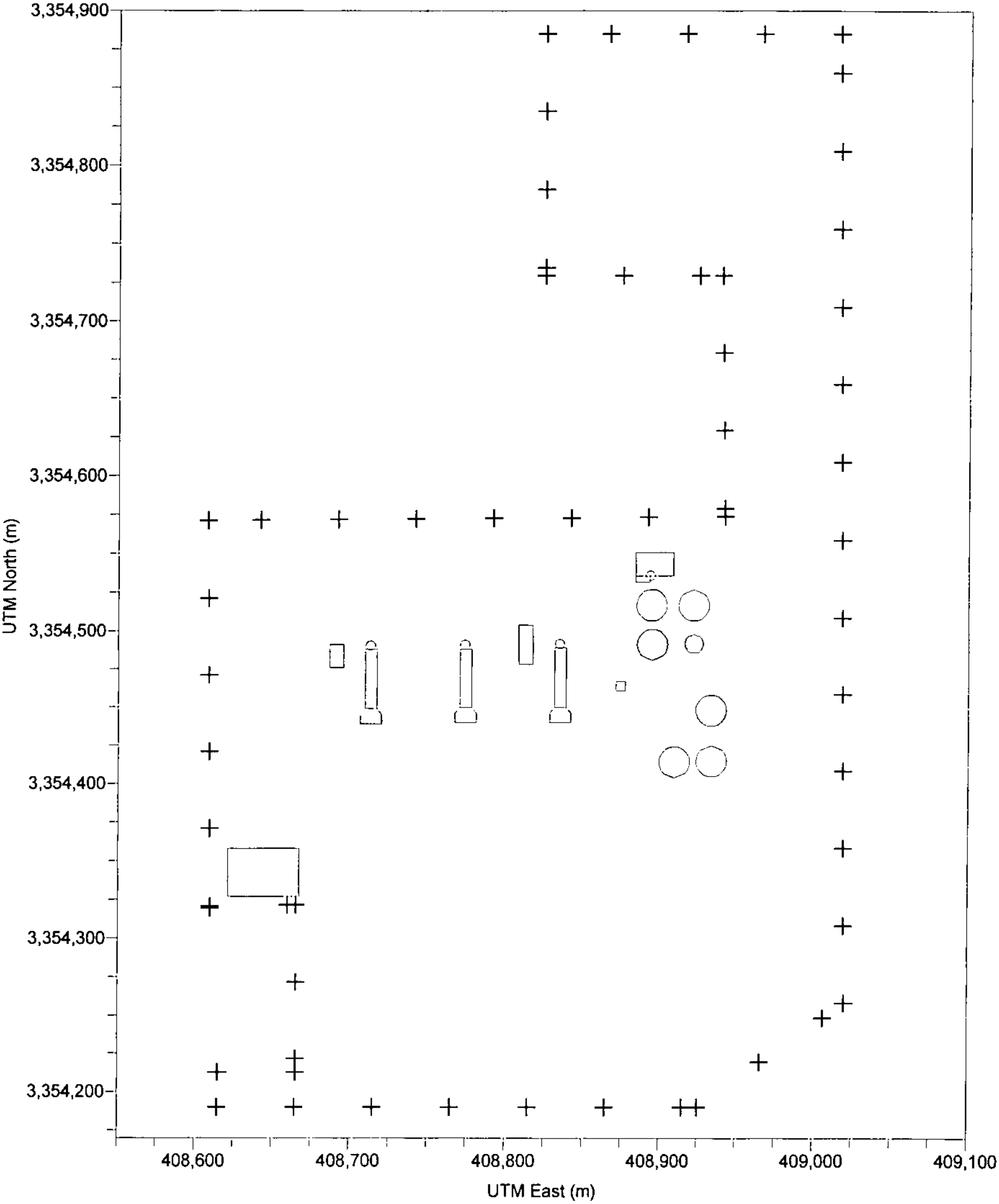

Brandy Branch Facility Plot Plan

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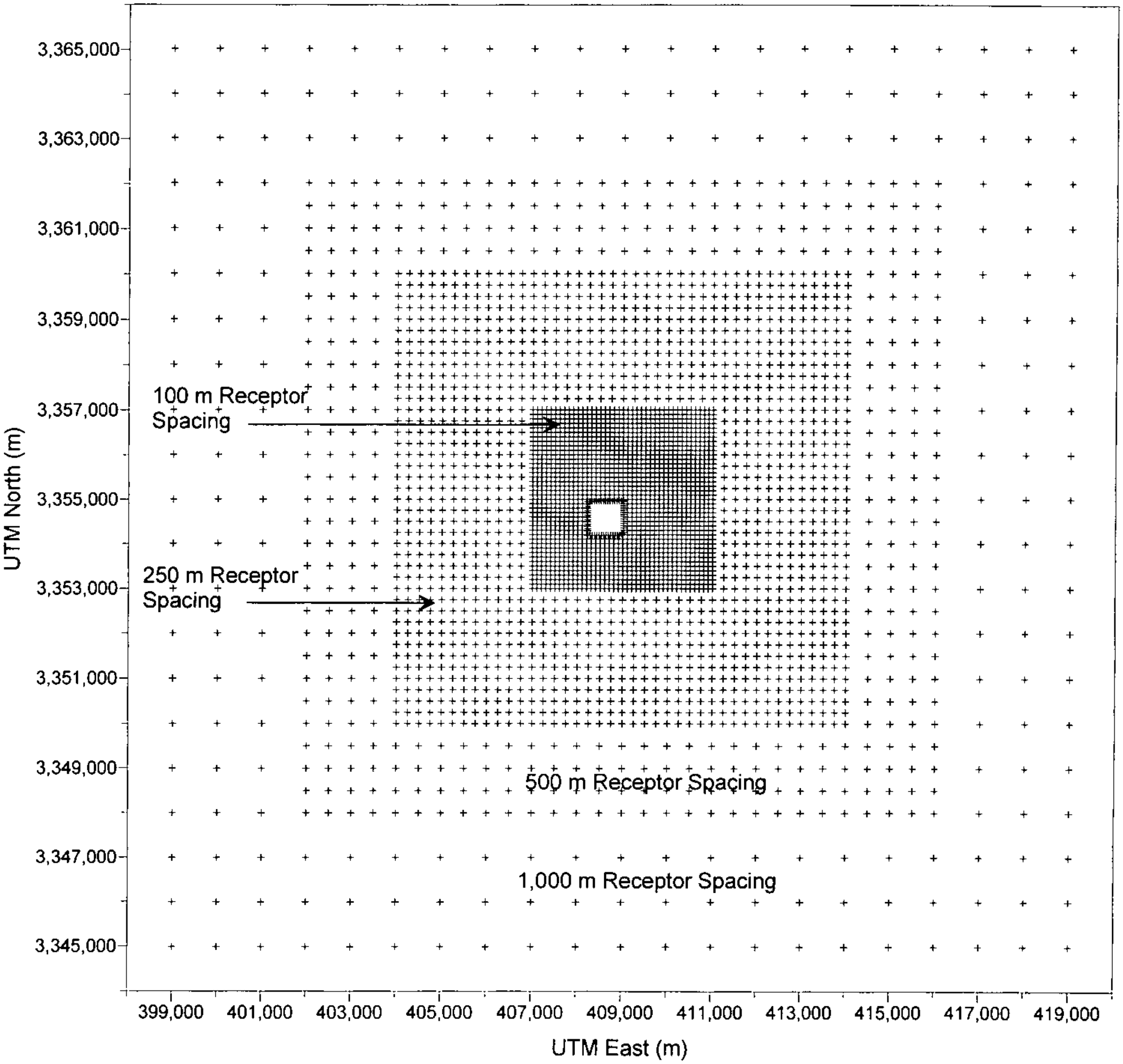

Receptor Locations

Figure 4-1

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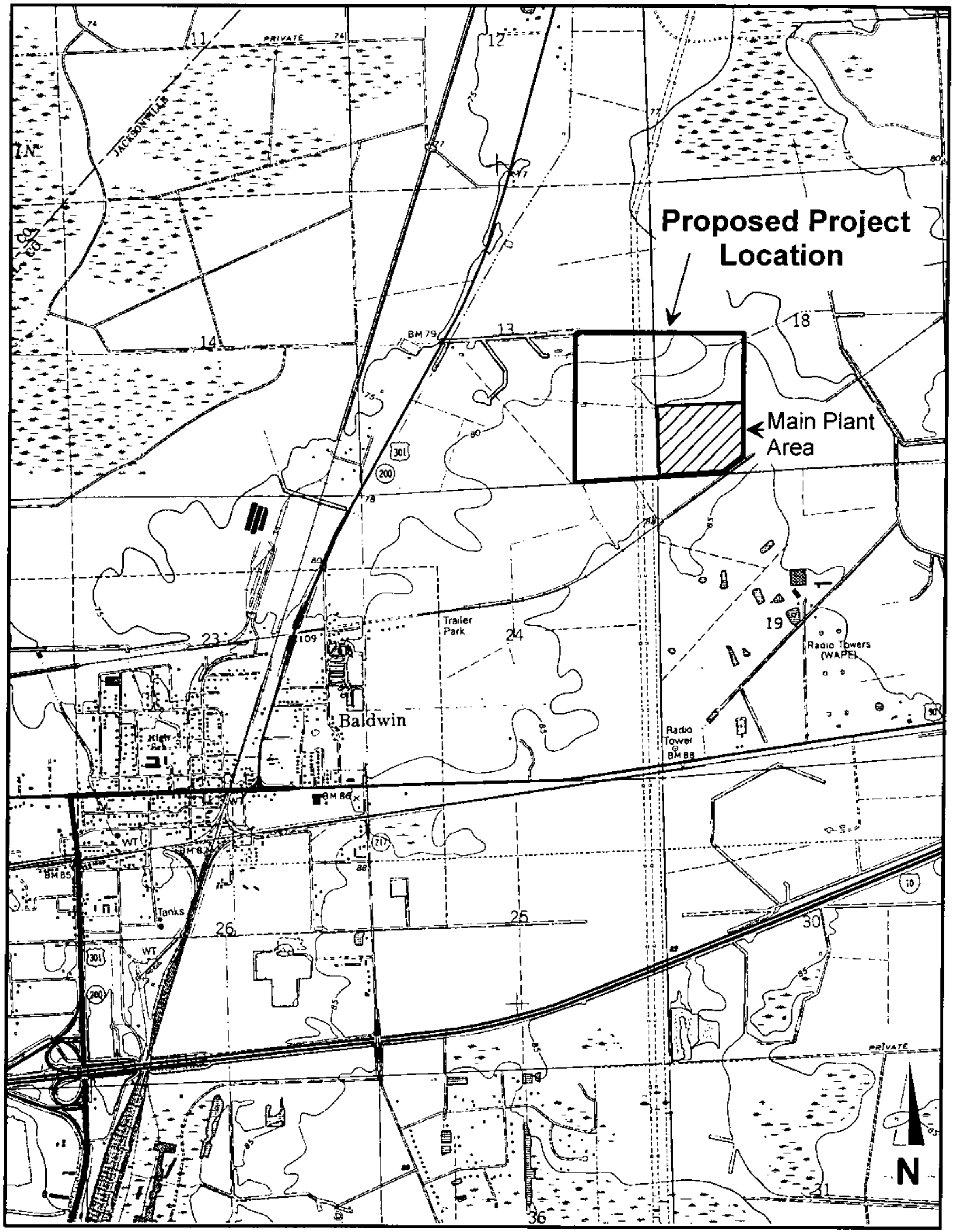
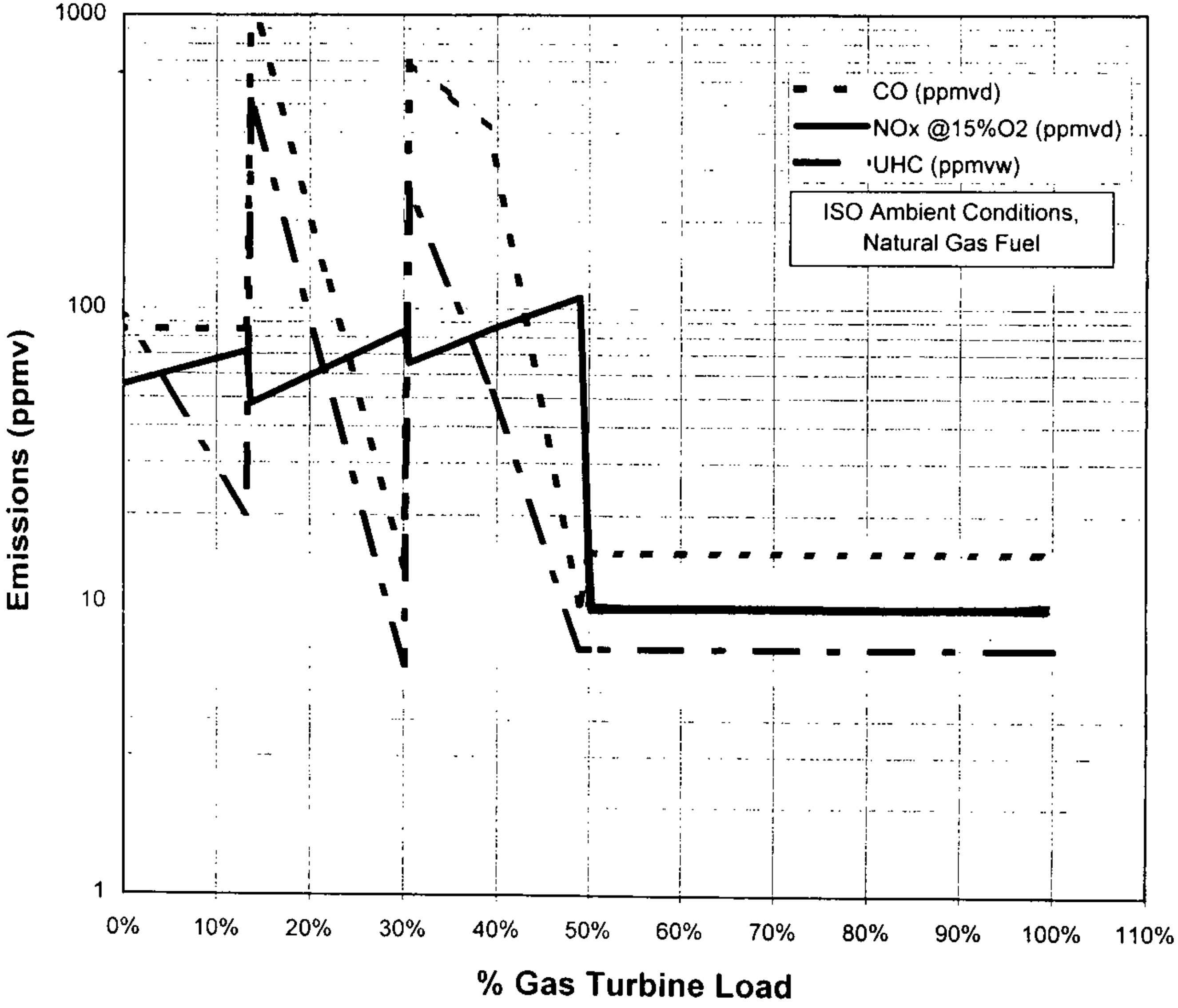


Source: USGS 7.5' Topographic, Baldwin, Florida Quadrangle

Proposed Project Location

Figure 2-1

PG7241FA with DLN2.6 Combustors
Estimated Emissions



UOGTF
January 1998

GE Industrial & Power Systems
Gas Turbine

Unit Operation/Turbine (Gas)

(Applicability MS7001FA, 9001FA)

I. REFERENCE DATA AND PRECAUTIONS

A. Operator Responsibility

It is essential that the turbine operators be familiar with the information contained in the following operation text, the Control Specification drawings (consult the Control System Settings drawing for the index of Control Specification drawings), the Piping Schematic drawings including the Device Summary (consult the Control System Settings Drawing for the index by model list and drawing number of applicable schematics), the SPEEDTRONIC® control sequence program and the SPEEDTRONIC® Mark V Users' Manual (GEH–5979). The operator must also be aware of the power plant devices which are tied into the gas turbine mechanically and electrically and could affect normal operation. No starts should be attempted whether on a new turbine or a newly overhauled turbine until the following conditions have been met:

1. Requirements listed under CHECKS PRIOR TO OPERATION have been met.
2. Control systems have been functionally checked for proper operation before restarting.
3. All GENERAL OPERATING PRECAUTIONS have been noted.

It is extremely important that gas turbine operators establish proper operating practices. We emphasize adherence to the following:

1. Respond to Annunciator Indicators — Investigate and correct the cause of the abnormal condition. This is particularly true for the protection systems, such as low oil pressure, overtemperature, vibration, overspeed etc.
2. Check of Control Systems — After any type of control maintenance is completed, whether repair or replacement of parts, functionally check control systems for proper operation. This should be done prior to restart of the turbine. It should not be assumed that reassembly, "as taken apart" is adequate without the functional test.
3. Monitor Exhaust Temperature During All Phases of Startup — The operator is alerted to the following:

CAUTION

Overtemperature can damage the turbine hot gas path parts.

Monitor exhaust temperature for proper control upon first startup and after any turbine maintenance is performed. Trip the turbine if the exhaust temperature exceeds the normal trip level, or increases at an unusual rate. A particularly critical period for overtemperature damage to occur is during the startup phase before the turbine reaches governing speed. At this time air flow is low and the turbine is unable to accelerate away from excess fuel.

B. General Operating Precautions

1. Temperature Limits

Refer to the Control Specifications for actual exhaust temperature control settings. It is important to define a "baseline value" of exhaust temperature spread with which to compare future data. This baseline data is established during steady state operation after each of the following conditions:

a. Initial startup of unit

b. Before and after a planned shut-down

c. Before and after planned maintenance

An important point regarding the evaluation of exhaust temperature spreads is not necessarily the magnitude of the spread, but the change in spread over a period of time. The accurate recording and plotting of exhaust temperatures daily can indicate a developing problem. Consult Control Specification-Settings Drawings for maximum allowable temperature spreads and wheelspace temperature operating limits.

The wheelspace thermocouples, identified together with their nomenclature, are on the Device Summary. A bad thermocouple will cause a "High Wheelspace Differential Temperature" alarm. The faulty thermocouple should be replaced at the earliest convenience.

When the average temperature in any wheelspace is higher then the temperature limit set forth in the table, it is an indication of trouble. High wheelspace temperature may be caused by any of the following faults:

1. Restriction in cooling air lines
2. Wear of turbine seals
3. Excessive distortion of the turbine stator
4. Improper positioning of thermocouple
5. Malfunctioning combustion system
6. Leakage in external piping
7. Excessive distortion of exhaust inner diffuser

Check wheelspace temperatures very closely on initial startup. If consistently high, and a check of the external cooling air circuits reveals nothing, it is permissible to increase the size of the cooling air orifices slightly. Consult with a General Electric Company field representative to obtain recommendations as to the size that an orifice should be increased. After a turbine overhaul, all orifices should be changed back to their original size, assuming that all turbine clearances are returned to normal and all leakage paths are corrected.

CAUTION

> Wheelspace temperatures are read on the <I> CRT. Temperatures in excess of the maximum are potentially harmful to turbine hot-gas-path parts over a prolonged period of time. Excessive temperatures are annunciated but will not cause the turbine to trip. High wheelspace temperature readings must be reported to the General Electric technical representative as soon as possible.

2. Pressure Limits

Refer to the Device Summary for actual pressure switch settings. Lube oil pressure in the bearing feed header is a nominal value of 25 psig. The turbine will trip at 8 psig. Pressure variations between these values will result from entrapped particulate matter within the lube oil filtering system.

3. Vibration Limits

The maximum overall vibration velocity of the gas turbine should never exceed 1.0 inch (2.54 cm) per second in either the vertical or horizontal direction. Corrective action should be initiated when the vibration levels exceed 0.5 inch (1.27 cm) per second as indicated on the SPEEDTRONIC® <I> CRT.

If doubt exists regarding the accuracy of the reading or if more accurate and specific vibration readings are desired a vibration check is recommended using vibration test equipment.

4. Load Limit

The maximum load capability of the gas turbine is given in the control specification. For the upper limits of generator capability, refer to the Reactive Capability Curve following the GENERATOR AND ACCESSORIES tab.

5. Overloading of Gas Turbine, Facts Involved and Policy

It is General Electric practice to design gas turbines with margins of safety to meet the contract commitments and to secure long life and trouble-free operation.

So that maximum trouble-free operation can be secured, General Electric designs these machines with more than ample margins on turbine bucket thermal and dynamic stresses, compressor and turbine wheel stresses, generator ventilation, coolers, etc. As a result, these machines are designed somewhat better than is strictly necessary, because of the importance of reliability of these turbines to our customers and to the electrical industry.

It cannot be said, therefore, that these machines cannot be safely operated beyond the load limits. Such operation, however, always encroaches upon the design margins of the machines with a consequent reduction in reliability and increased maintenance. Accordingly, any malfunction that occurs as a result of operation beyond contract limits cannot be the responsibility of the General Electric Company.

The fact that a generator operates at temperature rises below the 185F (85C) for the rotor and 140F (60C) for the stator permitted by the AIEE Standards does not mean that it can be properly run with full safety up to these values by overloading beyond the nameplate rating. These standards were primarily set up for the protection of insulation from thermal deterioration on small machines. The imbedded temperature detectors of the stator register a lower temperature than the copper because of the temperature drop through the insulation from the copper to the outside of the insulation, where the temperature detectors are located. There are also conditions of conductor expansion, insulation stress, etc., which impose limitations. These factors have been anticipated in the "Vee" curves and reactive capability curves which indicate recommended values consistent with good operating practice. The "Vee" curves and reactive capability curves form part of the operating instructions for the generator and it is considered unwise to exceed the values given.

The gas turbines are mechanically designed so that (within prescribed limits), advantage can be taken of the increased capability over nameplate rating, which is available at lower ambient temperatures (because of increased air density), without exceeding the maximum allowable turbine inlet temperature.

The load limit of the gas turbine–generator must not be exceeded, even when the ambient temperature is lower than that at which the load limit of the gas turbine is reached. Under these conditions, the gas turbine will operate at this load with a lower turbine inlet temperature and the design stresses on the load coupling and turbine shaft will not be exceeded.

If the turbine is overloaded so that the turbine exhaust temperature schedule is not followed for reasons of malfunctioning or improper setting of the exhaust temperature control system, the maximum allowable turbine inlet temperature or the maximum allowable exhaust temperature, or both, will be exceeded and will result in a corresponding increase in maintenance and, in extreme cases, might result in failure of the turbine parts.

The exhaust temperature control system senses the turbine exhaust temperature and introduces proper bias to limit the fuel flow so that neither the maximum allowable turbine inlet temperature nor the maximum allowable turbine exhaust temperature is exceeded.

6. Fire Protection System Operating Precautions

The fire protection system, when actuated, will cause several functions to occur in addition to actuating the media discharge system. The turbine will trip, an audible alarm will sound, and the alarm message will be displayed on the <I> CRT. The ventilation openings in the compartments will be closed by a pressure-operated latch and the damper in the turbine shell cooling discharge will be actuated.

The annunciator audible alarm may be silenced by clicking on the alarm SILENCE target. The alarm message can be cleared from the ALARM list on the <I> CRT after the ACKNOWLEDGE target and the ALARM RESET target are actuated, but only after the situation causing the alarm has been corrected.

The fire protection system *must be replenished and reset* before it can automatically react to another fire. Reset must be made after each activation of the fire protection system which includes an initial discharge followed by an extended discharge period of the fire protection media.

Fire protection system reset is accomplished by resetting the pressure switch located on the fire protection system.

Ventilation dampers, automatically closed by a signal received from the fire protection system, must be reopened manually in all compartments before restarting the turbine.

CAUTION

> Failure to reopen compartment ventilation dampers will severely shorten the service life of major accessory equipment. Failure to reopen the load coupling compartment dampers will materially reduce the performance of the generator.

7. Combustion System Operating Precautions

WARNING

> **Sudden emission of black smoke may indicate a possibility of outer casing failure or other serious combustion problems. In such an event:**

a. Immediately shut down the turbine.

b. Allow no personnel inside the turbine compartment until turbine is shut down.

c. Caution all personnel against standing in front of access door openings into pressurized compartments.

d. Perform a complete combustion system inspection.

To reduce the possibility of combustion outer casing failure, the operator should adhere to the following:

a. During operation, exhaust temperatures are monitored by the SPEEDTRONIC® control system. The temperature spread is compared to allowable spreads with alarms and/or protective trips resulting if the allowable spread limits are exceeded.

b. After a trip from 75% load or above, observe the exhaust on startup for black or abnormal smoke and scan the exhaust thermocouples for unusually high spreads. Record temperature spread during a normal startup to obtain base line signature for comparison. Excessive tripping should be investigated and eliminated.

c. Adhere to recommended inspection intervals on combustion liners, transition pieces and fuel nozzles.

Operating a turbine with non-operational exhaust thermocouples increases the risk of turbine overfiring and prevents diagnosis of combustion problems by use of temperature differential readings.

To prevent the above described malfunctions the operator should keep the number of non-operational exhaust thermocouples to a maximum of two but no more than *one* of any three adjacent thermocouples.

CAUTION

> Operation of the gas turbine with a single faulty thermocouple should not be neglected, as even one faulty thermocouple will increase the risk of an invalid "combustion alarm" and/or "Trip". The unit should not be shut down just for replacement of a single faulty thermocouple. However, every effort should be made to replace the faulty thermocouples when the machine is down for any reason.

Adherence to the above criteria and early preventive maintenance should reduce distortions of the control and protection functions and the number of unnecessary turbine trips.

8. Cooldown/Shutdown Precautions

CAUTION

> In the event of an emergency shutdown in which internal damage of any rotating equipment is suspected, do not turn the rotor after shutdown. Maintain lube oil pump operation, since lack of circulating lube oil following a hot shutdown will result in rising bearing temperatures which can result in damaged bearing surfaces. If the malfunction that caused the shutdown can be quickly repaired, or if a check reveals no internal damage affecting the rotating parts, reinstate the cooldown cycle.

If there is an emergency shutdown and the turbine is not turned with the rotor turning device, the following factors should be noted:

a. Within 20 minutes, maximum, following turbine shutdown, the gas turbine may be started without cooldown rotation. Use the normal starting procedure.

b. Between 20 minutes and 48 hours after shutdown a restart should not be attempted unless the gas turbine rotor has been turned from one to two hours.

c. If the unit has been shut down and not turned at all, it must be shut down for approximately 48 hours before it can be restarted without danger of shaft bow.

CAUTION

> Where the gas turbine has not been on rotor turning operation after shutdown and a restart is attempted, as under conditions (1) and (2) above, the operator should maintain a constant check on vibration velocity as the unit is brought up to its rated speed. If the vibration velocity exceeds one inch per second at any speed, the unit should be shut down and the shaft rotated for at least one hour before a second starting attempt is made. If seizure occurs during the turning operation of the gas turbine, the turbine should be shut down and remain idle for at least 30 hours, or until the rotor is free. The turbine may be rotated at any time during the 30-hour period if it is free; however, audible checks should be made for rubs.

Note: **The vibration velocity must be measured at points near the gas turbine bearing caps.**

II. PREPARATIONS FOR NORMAL LOAD OPERATION

A. Standby Power Requirements

Standby AC power insures the immediate startup capability of particular turbine equipment and related control systems when the start signal is given. Functions identified by asterisk are also necessary for unit environmental protection and should not be turned off except for maintenance work on that particular function. Standby AC power is required for:

1. Lube oil heaters, which when used in conjunction with the lube oil pumps, heat and circulate turbine lube oil at low ambient temperatures to maintain proper oil viscosity.
2. *Control panel heating.
3. *Generator heating.
4. Lube oil pumps. Auxiliary pump should be run at periodic intervals to prevent rust formation in the lube oil system.
5. Fuel oil heaters, where used. These heaters used in conjunction with the fuel oil pumps, heat and circulate fuel oil at low ambient temperatures to maintain proper fuel oil viscosity.
6. Compartment heating.
7. *Operation of control compartment air conditioner during periods of high ambient temperature to maintain electrical equipment insulation within design temperature limits.
8. *Battery charging (where applicable).

B. Checks Prior to Operation

The following checks are to be made before attempting to operate a new turbine or an overhauled turbine. It is assumed that the turbine has been assembled correctly, is in alignment and that calibration of the

SPEEDTRONIC® system has been performed per the Control Specifications. A standby inspection of the turbine should be performed with the lube oil pump operating and emphasis on the following areas:

1. Check that all piping and turbine connections are securely fastened and that all blinds have been removed. Most tube fittings incorporate a stop collar which insures proper torquing of the fittings at initial fitting make up and at reassembly. These collars fit between the body of the fitting and the nut and contact in tightening of the fitting. The stop collar is similar to a washer and can be rotated freely on unassembled fittings. During initial assembly of a fitting with a stop collar, tighten the nut until it bottoms on the collar. The fitting has to be sufficiently tightened until the collar cannot be rotated by hand. This is the inspection for a proper fitting assembly. For each remake of the fitting, the nut should again be tightened until the collar cannot be rotated.
2. Inlet and exhaust plenums and associated ducting are clean and rid of all foreign objects. All access doors are secure.
3. Where fuel, air or lube oil filters have been replaced check that all covers are intact and tight.
4. Verify that the lube oil tank is within the operating level and if the tank has been drained that it has been refilled with the recommended quality and quantity of lube oil. If lube oil flushing has been conducted verify that all filters have been replaced and any blinds if used, removed.
5. Check operation of auxiliary and emergency equipment, such as lube oil pumps, water pumps, fuel forwarding pumps, etc. Check for obvious leakage, abnormal vibration (maximum 3 mils), noise or overheating.
6. Check lube oil piping for obvious leakage. Also using provided oil flow sights, check visually that oil is flowing from the bearing drains. The turbine should not be started unless flow is visible at each flow sight.
7. Check condition of all thermocouples and/or resistance temperature detectors (RTDs) on the <I> CRT. Reading should be approximately ambient temperature.
8. Check spark plugs for proper arcing.

WARNING

Do not test spark plugs where explosive atmosphere is present.

If the arc occurs anywhere other than directly across the gap at the tips of the electrodes, or if by blowing on the arc it can be moved from this point, the plug should be cleaned and the tip clearance adjusted. If necessary, the plug should be replaced. Verify the retracting piston for free operation.

9. Devices requiring manual lubrication are to be properly serviced.
10. Determine that the cooling water system has been properly flushed and filled with the recommended coolant. Any fine powdery rust, which might form in the piping during short time exposure to atmosphere, can be tolerated. If there is evidence of a scaly rust, the cooling system should be power flushed until all scale is removed. If it is necessary to use a chemical cleaner, most automobile cooling system cleaners are acceptable and will not damage the carbon and rubber parts of the pump mechanical seals or rubber parts in the piping.

Refer to "Cooling Water Recommendations for Combustion Gas Turbine Closed Cooling Systems" included under tab titled Fluid Specifications. Note the following regarding antifreeze.

CAUTION

Do not change from one type antifreeze to another without first flushing the cooling system very thoroughly. Inhibitors used may not be compatible and can cause formation of gums, in addition to destroying effectiveness as an inhibitor. Consult the antifreeze vendor for specific recommendations.

Following the water system refill ensure that water system piping, primarily pumps and flexible couplings, do not leak. It is wise not to add any corrosion inhibitors until after the water system is found to be leak free.

11. The Load Commutator Inverter (LCI) should be calibrated and tested as per GEH–6192.
12. The use of radio transmitting equipment in the vicinity of open control panels is not recommended. Prohibiting such use will assure that no extraneous signals are introduced into the control system that might influence the normal operation of the equipment.
13. Check the Cooling and Sealing Air Piping against the assembly drawing and piping schematic, to ensure that all orifice plates are of designated size and in designated positions.
14. At this time all annunciated ground faults should be cleared. It is recommended that units not be operated when a ground fault is indicated. Immediate action should be taken to locate all grounds and correct the problems.

C. Checks During Start Up and Initial Operation

The following is a list of important checks to be made on a new or newly overhauled turbine with the OPERATION SELECTOR switch in various modes. The Control Specifications — Control Systems Adjustments should be reviewed prior to operating the turbine.

CAUTION

Where an electric motor is used as the starting means refer to the Control Specifications for maximum operating time.

When a unit has been overhauled those parts or components that have been removed and taken apart for inspection/repair should be critically monitored during unit startup and operation. This inspection should include: leakage check, vibration, unusual noise, overheating, lubrication.

1. Crank

a. Listen for rubbing noises in the turbine compartment especially in the load tunnel area. A soundscope or some other listening type device is suggested. Shutdown and investigate if unusual noise occurs.

b. Check for unusual vibration.

c. Inspect for water system leakage.

2. Fire

*** * * WARNING * * ***

Due to the complexity of gas turbine fuel systems, it is imperative for everyone to exercise extreme caution in and near any turbine compartment, fuel handling system, or any other enclosures or areas containing fuel piping or fuel system components.

Do not enter the turbine compartment unless absolutely necessary. When it is necessary, exercise caution when opening and entering the compartment. Be aware of the possibility of fuel leaks, and be prepared to shut down the turbine and take action if a leak is discovered.

At any time, if/when entering the turbine compartment or when in the vicinity of the fuel handling system or other locations with fuel piping, fuel system components, or fuel system connections, while the turbine is operating, implement the following:

> **Conduct an environmental evaluation of the turbine compartment, fuel handling system, or specific area. Pay particular attention to all locations where fuel piping/components/connections exist.**
>
> **Follow applicable procedures for leak testing. If fuel leaks are discovered, exit the area quickly, shut the turbine down, and take appropriate actions to eliminate the leak(s).**
>
> **Require personnel entering the turbine comparrtment to be fitted with the appropriate personal protective equipment, i.e., hard hat, safety glasses, hearing protection, harness/manline (optional depending on space constraints), heat resistant/flame retardant coveralls and gloves.**
>
> **Establish an attendant to maintain visual contact with personnel inside the turbine compartment and radio communications with the control room operator.**

During the first start-up after a disassembly, visually check all connections for fuel leaks. Preferably check the fittings during the warm-up period when pressures are low. Visually inspect the fittings again at full speed, no load, and at full load. Do not attempt to correct leakage problems by tightening fittings and/or bolting while lines are fully pressurized. Note area in question and, depending on severity of leak, repair at next shutdown, or if required shut unit down immediately. Attempts to correct leakage problem on pressurized lines could lead to sudden and complete failure of component and resulting damage to equipment and personnel injury.

a. Bleed fuel oil filters, if appropriate. Then check entire fuel system and the area immediately around the fuel nozzle for leaks. In particular check for leaks at the following points:

Turbine Compartment

(1) Fuel piping/tubing to fuel nozzle

(2) Fuel check valves

(3) Atomizing air manifold and associated piping (when used)

(4) Gas manifold and associated piping (when used)

Accessory Module

(1) Flow divider (when used)

(2) Fuel and water pumps

(3) Filter covers and drains

CAUTION

> Elimination of fuel leakage in the turbine compartment is of extreme importance as a fire preventive measure.

b. Monitor FLAME status on the <I> processor to verify all flame detectors are correctly indicating flame.

c. Monitor the turbine control system readings on the <I> processor for unusual exhaust thermocouple temperature, wheelspace temperature, lube oil drain temperature, highest to lowest exhaust temperature spreads and "hot spots" i.e. combustion chamber(s) burning hotter than all the others.

d. Listen for unusual noises and rubbing.

e. Monitor for excessive vibration.

3. Automatic, Remote

On initial startup, permit the gas turbine to operate for a 30 to 60 minute period in a full speed, no load condition. This time period allows for uniform and stabilized heating of the parts and fluids. Tests and checks listed below are to supplement those recorded in Control Specification — Control System Adjustments. Record all data for future comparison and investigation.

a. Continue monitoring for unusual rubbing noises and shutdown immediately if noise persists.

b. Monitor lube oil tank, header and bearing drain temperatures continually during the heating period. Refer to the Schematic Piping Diagram — Summary Sheets for temperature guidelines. Adjust VTRs if required.

c. At this time a thorough vibration check is recommended, using vibration test equipment such as IRD equipment (IRD Mechanalysis, Inc.) or equivalent with filtered or unfiltered readings. It is suggested that horizontal, vertical and axial data be recorded for the:

(1) all accessible bearing covers on the turbine

(2) turbine forward compressor casing

(3) turbine support legs

(4) bearing covers on the load equipment

d. Check wheelspace, exhaust and control thermocouples for proper indication on the <I> CRT. Record these values for future reference.

e. Flame detector operation should be tested per the Control Specification — Control System Adjustments.

f. Utilize all planned shutdowns in testing the Electronic and Mechanical Overspeed Trip System per the Control Specifications — Control System Adjustments. Refer to Special Operations section of this text.

g. Monitor <I> CRT display data for proper operation.

III. OPERATING PROCEDURES

A. General

The following instructions pertain to the operation of a model series 7001FA or 9001FA gas turbine unit designed for generator drive application. These instructions are based on use of Mark V SPEEDTRONIC® turbine control panels.

Functional description of the <I> CRT Main Display follows; however, panel installation, calibration, and maintenance are not included.

Operational information includes startup and shutdown sequencing in the AUTO mode of operation. The most common causes of alarm messages can be found in the concluding section.

It is not intended to cover initial turbine operation herein; rather, it will be assumed that initial startup, calibration and checkouts have been completed. The turbine is in the cooldown or standby mode ready for normal operation with AC and DC power available for all pumps, motors, heaters, and controls and all annunciator drops are cleared.

Refer to the Control Specifications (Control and Protection Systems) in this volume, and the previously furnished Control Sequence Program (CSP) for additional operating sequence information and related diagrams.

B. Start-Up

1. General

Operation of a single turbine/generator unit may be accomplished either locally or remotely.

The following description lists operator, control system and machine actions or events in starting the gas turbine.

Reference the section "Description of Panels and Terms — Turbine Control Panel" for description of turbine panel devices. The following assumes that the unit is off of cooldown, and in a ready to start condition.

2. Starting Procedure

a. Using the cursor positioning device, select "MAIN" display from the DEMAND DISPLAY menu.

(1) The display will indicate speed, temperature, various conditions etc. Three lines displayed on the <I> CRT will read:

SHUTDOWN STATUS
OFF COOLDOWN
OFF

b. Select "AUTO" and "EXECUTE"

(1) The <I> CRT display will change to:

STARTUP STATUS
READY TO START
AUTO

c. Select "START" and "EXECUTE"

(1) Unit auxiliaries will be started including a motor driven lube oil pump used to establish lube oil pressure. The <I> CRT message SEQ IN PROGRESS will appear.

(2) When permissives are satisfied, the master protective logic (L4) will be satisfied. The CRT display will change to:

STARTUP STATUS
STARTING
AUTO;
START

(3) The turbine shaft will begin to rotate on turning gear. The zero speed signal "14HR" will be displayed. When the unit reaches approximately 6 rpm, the starting device will be energized and accelerate the unit. The <I> CRT display will change to START–UP STATUS/CRANKING.

(4) When the unit reaches approximately 15% speed, the minimum speed signal "14HM" will be displayed on the <I> CRT. (For machines with cooling water fan motors receiving power from the generator terminals via the UCAT transformer, field flashing will be initiated to build up generator voltage to power the fans; otherwise, field flashing to build up generator voltage will occur at operating speed.)

(5) If the unit configuration requires purging of the gas path prior to ignition, the starting device will crank the gas turbine at purge speed for a period of time determined by the setting of the purge timer. See Control Specifications-Settings Drawing for purge timer settings.

(6) FSR will be set to firing value. (FSR, Fuel Stroke Reference, is the electrical signal that determines the amount of fuel delivered to the turbine combustion system.) Ignition sequence is initiated. The <I> CRT display will change to START UP STATUS/FIRING.

(7) When flame is established, the <I> CRT display will indicate flame in those combustors equipped with flame detectors.

(8) FSR is set back to warm-up value, and the <I> CRT display will indicate STARTUP STATUS/WARMING UP. If the flame goes out during the 60 second firing period, FSR will be reset to firing value. (At the end of the ignition period, if flame has not been established, the unit will remain at firing speed. Refer to operation 8 in the Special Operations section for specific operating instructions for DLN 2.0 and DLN 2.6 configured machines.) At this time the operator may shut the unit down or attempt to fire again. To fire again select CRANK on the Main Display. The purge timer and firing timer are reinitialized. The purge timer will begin to time. Reselecting AUTO will cause the ignition sequence to repeat itself after the purge timer has timed out. If the unit is being operated remotely and multiple starts capability exists (REMOTE having previously been selected on the Main Display), and no fire has been established at the end of the ignition period, the unit will be purged of unburned fuel. At the end of the purge period ignition will be attempted again. If flame is not established at this time, the starting sequence will be terminated and the unit will shutdown.

At the end of the warmup period, with flame established, FSR will begin increasing. The <I> CRT will indicate STARTUP STATUS/ACCELERATING and the turbine will increase in speed. At approximately 50% speed, the accelerating speed signal "14HA" will be displayed on the <I> CRT.

(9) The turbine will continue to accelerate. When it reaches 85–90% speed, the starting device will disengage and shutdown. The <I> CRT will indicate the change in status from STARTUP CONTROL to SPEED CONTROL at approximately 60% speed.

(10) When the turbine reaches operating speed, the operating speed signal "14HS" will be displayed on the <I> CRT. Field flashing is terminated. If the synchronizing selector switch (43S) on the generator control panel is in the OFF position and REMOTE is not selected on the <I> CRT, as the turbine reaches operating speed, <I> CRT will now read:

RUN STATUS
FULL SPEED NO LOAD
AUTO; START

If the synchronizing selector switch on the generator panel is in the AUTO position or REMOTE is selected on the <I> CRT automatic synchronizing is initiated. The <I> CRT will read SYNCHRONIZING.

The turbine speed is matched to the system (to less than 1/3 Hz difference) and when the proper phase relationship is achieved the generator breaker will close. The machine will load to Spinning Reserve unless a load control point BASE, PEAK or PRESELECTED LOAD has been selected.

The <I> CRT will display SPINNING RESERVE, once the unit has reached this load point.

C. Synchronizing

When a gas turbine-driven synchronous generator is connected into a power transmission system, the phase angle of the generator going on-line must correspond to the phase angle of the existing line voltage at the moment of its introduction into the system. This is called synchronizing.

CAUTION

> Before initiating synchronization procedures, be sure that all synchronization equipment is functioning properly, and that the phase sequence of the incoming unit corresponds to the existing line phase sequence and the potential transformers are connected correctly to proper phases. Initial synchronization and checkout after performing maintenance to synchronizing equipment should be performed with the breaker racked out.

Note: **Synchronizing cannot take place unless AUTO or REMOTE has been selected on the <I> CRT Main Display and the turbine has reached full speed.**

Generator synchronization can be accomplished either automatically or manually. Manual synchronization is accomplished by the following procedure:

1. Place the synchronizing selector switch on the generator panel (43S) in the MANUAL position.
2. Select AUTO on the <I> CRT Main Display.
3. Select START and EXECUTE on the <I> CRT Main Display. This will start the turbine and accelerate it to full speed as previously described. At this point the CRT will indicate RUN STATUS, FULL SPEED NO LOAD.
4. Compare the generator voltage with the line voltage. (These voltmeters are located on the generator control panel.)
5. Make any necessary voltage adjustment by operating the RAISE- LOWER (90R4) switch on the generator panel until the generator voltage equals the line voltage.
6. Compare the generator and line frequency on the synchroscope (located on the generator control panel). If the pointer is rotating counterclockwise, the generator frequency is lower than the line frequency and should be raised by increasing the turbine-generator speed. The brightness of the synchronizing lights will change with the rotation of the synchroscope. When the lights are their dullest the synchroscope will be at the 12 o'clock position. The lights should not be used to synchronize but only to verify proper operation of the synchroscope.
7. Adjust the speed until the synchroscope rotates clockwise at approximately five seconds per revolution or slower.
8. The generator circuit breaker "close" signal should be given when it reaches a point approximately one minute before the 12 o'clock position. This allows for a time lag for the breaker contacts to close after receiving the close signal.

Automatic synchronization is accomplished by the following steps:

1. Place the synchronizing selector switch (43S) in the AUTO position.
2. Select AUTO on the <I> CRT Main Display.
3. Select START on the <I> CRT Main Display.

This procedure will start the turbine, and upon attainment of "complete sequence", match generator voltage to line voltage (if equipped with optional voltage matching), synchronize the generator to the line frequency, and load the generator to the preselected value. A "breaker closed" indicator will actuate when the generator circuit breaker has closed placing the synchronized unit on-line.

Once the generator has been connected to the power system, the turbine fuel flow may be increased to pick up load, and the generator excitation may be adjusted to obtain the desired KVAR value.

WARNING

Failure to synchronize properly may result in equipment damage and/or failure, or the creation of circumstances which could result in the automatic removal of generating capacity from the power system.

In those cases where out-of-phase breaker closures are not so serious as to cause immediate equipment failure or system disruption, cumulative damage may result to the on-coming generator. Repeated occurrences of out-of-phase breaker closures can eventually result in generator failure because of the stresses created at the time of closure.

Out-of-phase breaker closure of a magnitude sufficient to cause either immediate or cumulative equipment damage mentioned above will usually result in annunciator drops to notify the operator of the problem. The following alarms have been displayed at various occurrences of known generator breaker malclosures:

1. High vibration trip
2. Loss of excitation
3. Various AC undervoltage drops

Out-of-phase breaker closure will result in abnormal generator noise and vibration at the time of closure. If there is reason to suspect such breaker malclosure, the equipment should be immediately inspected to determine the cause of the malclosure and for any damage to the generator.

Refer to the "Control and Protection" section of this volume for additional information on the synchronizing system.

D. Normal Load Operation

1. Manual Loading

Manual loading is accomplished by clicking on the SPEED SP RAISE/SPEED SP LOWER targets on the <I> CRT Main Display.

Manual loading can also be accomplished by means of the governor control switch (70R4/CS) on the generator control panel. Holding the switch to the right will increase the load: holding it to the left will decrease the load.

Manual loading beyond the selected temperature control point BASE or PEAK is not possible. The manual loading rate is shown in the Control Specification-Settings Drawing.

Note: **When manually loading with the governor control switch (70R4/CS) for load changes greater than 25% of full load, the operator should not change more than 25% of full load in one minute.**

2. Automatic Loading

On startup if no load point is selected, the unit will load to the SPINNING RESERVE load point. The SPINNING RESERVE load point is slightly greater than no load, typically 8% of base rating.

An intermediate load point, PRE-SELECTED load, and temperature control load points BASE and PEAK can be selected anytime after a start signal has been given. The selection will be displayed on the <I> CRT. The unit will load to the selected load point. PRESELECTED LOAD is a load point greater than SPINNING RESERVE and less than BASE, typically 50%. The auto loading rate is shown in Control Specification-Settings Drawing.

E. Remote Operation

To transfer turbine control from the control compartment to remotely located equipment, select REMOTE on the <I> CRT Main Display. The turbine may then be started, automatically synchronized, and loaded by the remote equipment.

If manual synchronization is to be performed at the remote location, the synchronizing selector switch (43S) mounted on the generator control panel must be placed in the OFF/REMOTE position.

F. Shutdown and Cooldown

1. Normal Shutdown

Normal shutdown is initiated by selecting STOP on the <I> CRT Main Display. The shutdown procedure will follow automatically through generator unloading, turbine speed reduction, fuel shutoff at part speed and initiation of the cooldown sequence as the unit comes to rest.

2. Emergency Shutdown

Emergency shutdown is initiated by depressing the EMERGENCY STOP pushbutton. Cooldown operation after emergency shutdown is also automatic provided the permissives for this operation are met.

3. Cooldown

Immediately following a shutdown, after the turbine has been in the fired mode, the rotor is turned to provide uniform cooling. Uniform cooling of the turbine rotor prevents rotor bowing, resultant rubbing and imbalance, and related damage that might otherwise occur when subsequent starts are attempted without cooldown. The turbine can be started and loaded at any time during the cooldown cycle.

The cooldown cycle may be accelerated using the starting device; in which case it will be operated at cranking speed.

A rotor turning device is provided for cooldown rotation. A description of rotor turning operation and servicing can be found in the Starting System tab.

The minimum time required for turbine cooldown depends mainly on the turbine ambient temperature. Other factors, such as wind direction and velocity in outdoor installations and air drafts in indoor installations, can have an affect on the time required for cooldown. The cooldown times recommended in the following paragraphs are the result of General Electric Company operating experience in both factory and field testing of General Electric gas turbines. The purchaser may find that these times can be modified as experience is gained in operation of the gas turbine under his particular site conditions.

Cooldown times should not be accelerated by opening up the turbine compartment doors or the lagging panels since uneven cooling of the outer casings may result in excessive stress.

The unit must be on rotor turning operation immediately following a shutdown for at least 24 hours to ensure minimum protection against rubs and unbalance on a subsequent starting attempt. The General Electric Company, however, recommends that the rotor turning operation continue for 48 hours after shutdown to ensure uniform rotor cooling.

G. Special Operations

1. Fuel Transfer (Gas-Distillate Option)

Fuel transfer is initiated using the Fuel Mixture Display on the <I> CRT. When transferring from one fuel to the other, there is a thirty second delay before the transfer begins. For the gas-to-distillate transfer, the delay allows for filling the liquid fuel lines. For the distillate-to-gas transfer, the delay allows time for the speed ratio valve (and gas control valve) to modulate the inter volume gas pressure before the transfer begins. Once started, fuel transfer takes approximately thirty seconds. The transfer can be stopped at any fuel mixture proportion within limits as specified in the Control Specification-Settings Drawing by setting the FUEL MIX SETPOINT and then selecting MIX. Fuel transfer should be initiated prior to ignition or after the unit reaches operating speed.

2. Automatic Fuel Transfer On Low Gas Pressure (Gas-Distillate Option)

In the event of low fuel gas pressure the turbine will transfer to liquid fuel. The transfer will occur with no delay for line filling. To return to gas fuel operation after an automatic transfer, manually reselect gas fuel.

3. Testing the Emergency DC Lube Pump

The DC emergency pump may be tested using the test pushbutton on the motor starter.

4. Overspeed Trip Checks

Overspeed trip system testing should be performed on an annual basis on peaking and intermittently used gas turbines. On continuously operated units, the test should be performed at each scheduled shutdown and after each major overhaul. All units should be tested after an extended shutdown period of two or more months unless otherwise specified in the Control Specifications-Adjustments Drawing.

Note: The turbine should be operated for at least 30 minutes at rated speed before checking the overspeed settings.

Turbine speed is controlled by the turbine speed reference signal TNR. The maximum speed called for by TNR is limited by the high speed stop control constant. This value is nominally set at 107% of rated speed. It will be necessary to select the overspeed test function, which will reprogram the 107% setpoint to 113%, in order to allow the speed to increase above the electrical overspeed trip setting. With the high speed stop constant adjusted to be higher than the electrical overspeed trip speed, raise unit speed gradually by using the SPEED SP RAISE target on the <I> Main Display and observe speed at which the unit trips against the value tabulated in the Control Specifications — Setting drawing. Once the unit trips, the speed setpoint is returned to the 107% maximum value.

CAUTION

1. Do not exceed the maximum search speed as defined in the Control Specifications.
2. Return all constants to their normal value after coastdown of unit.

5. Steam Injection Operation (Optional)

Before operating the steam injection system for the first time following an overhaul or periods of extended shutdown, it is important that the following checks be made:

a. Steam supply is within design parameters

b. Instrument air supply is at required pressure

c. Steam line orifice size is correct

a. Pre-Operation Checks

Prior to operation, check for the following conditions:

a. <I> CRT controls are in non-select positions (Steam Injection OFF)

b. Manual stop valve is open

c. All hand valves in line of flow are open

d. All valves to temperature or pressure gauges are open

e. Steam supply pressure and temperature are in operating range

b. Startup

The automatic control system, in conjunction with logic circuits of the microcomputer of the SPEEDTRONIC® control system, operates the steam injection system control valving and assures that the proper amount of steam injection is provided to the turbine combustion system during operation.

To initiate steam injection the operator must first select the Steam Injection Overview Display on the <I> CRT. Selecting the STM INJ ON target initiates the steam injection control. At this point the automatic steam control circuits will take over, initiate the drain and stop valve sequences and control the system. When steam conditions are correct, the steam control valve releases steam into the combustion system at the proper steam-to-fuel flow ratio.

The startup and operating sequence of the steam injection system is described and explained in the Steam Injection control system text of the Control and Protection Tab.

c. Trouble Shooting

The purpose of the system is to provide steam to the turbine combustion system at the desired pressure, temperature and flow. If this does not happen, the following problems may be the cause:

(1) Steam supply exhausted

(2) Insufficient supply pressure

(3) Control valve closed

(4) Stop valve closed

The following should be checked:

(1) Adequate steam supply

(2) Check steam supply system

(3) Check control valve actuator and drain valve operation

(4) Check that instrument air supply pressure is sufficient and/or check solenoid control valve operation.

Alarm and shutdown conditions of the steam injection system are detected by a protection program built into Control Sequence Program. Alarm and trip indications are displayed on the <I> CRT. An alarm condition is initiated by high or low pressure levels and by high or low temperatures. See Control Specifications for alarm and trip point values.

The computer program is designed to trip the steam stop valve and prevent steam flow if steam temperature becomes too high or too low. It can trip the system on temperature or pressure to protect against loss of superheat and carry over of condensate. Steam at too high a pressure can cause damage to valve stem packing and system seals. A steam injection trip only shuts down the steam injection system. It does not trip the turbine.

6. DLNx II SYSTEM OPERATION

a. General

The Dry Low Nox II control system regulates the distribution of fuel delivered to multi–nozzle combustors located around the gas turbine. This system stages the fuel through multiple modes of operation to attain the low emissions mode of **Premix**. DLN–2 has only one burning zone but multiple nozzles and manifolds.

b. Gas Fuel Operation

There are three basic modes for fuel distribution to the combustor:

(1) Primary

Fuel to primary manifold only

(2) Lean–Lean

Fuel to primary and tertiary manifolds

(3) Premix

In this mode, fuel is in both the secondary and tertiary manifolds. This is the low emission mode.

c. Valves

There are four main valves in DLN–2:

Primary Gas Control Valve (GCVP)

Secondary Gas Control Valve (GCVS)

Quaternary Gas Control Valve (GCVQ)

Premix Splitter Valve (PMSV)

The PMSV is used downstream of the secondary gas control valve. This valve controls the flow between 4 secondary nozzles and 1 tertiary nozzle (The tertiary nozzle is not used during Primary mode).

d. Startup and Load Sequence

The gas turbine will startup with fuel going to primary manifold only and will accelerate to 81% corrected speed. At this point fuel flow will be initiated into the tertiary manifold and Lean–Lean will be established. As the unit is loaded to approximately 60% load (with no Bleed Heat), or 40% load (with Bleed Heat) a transfer to Premix will be performed. When transferring to Premix, the primary gas control valve will close, the secondary gas control valve will open,and the Premix splitter valve will modulate to control the flow between the tertiary and secondary nozzles. Once the Primary control valve is closed, the Primary Purge System wil open to purge the primary nozzles.

The sequence of events on an unload is as follows:

(1) Premix to Transfer Mode

(2) Premix Transfer to Lean–Lean

(3) Fired shutdown in Lean–Lean

The mode selection is performed automatically in the control system when the turbine is at the proper operating conditions.

These conditions must be met before startup; The following valves must be in the closed position:

Stop/Speed Ratio

Primary Control Valve (GCVP)

Secondary Control Valve (GCVS)

Quaternary Control Valve (GCVQ)

The Premix Splitter Valve (PMSV) should be at 100% split (no secondary flow).

Bleed Heat Valve closed (If applicable)

e. Inlet Guide Vane Operation (IGV)

The DLN–2 combustor emission performance is sensitive to changes in fuel to air ratio. The DLNx combustor was designed according to the airflow regulation scheme used with IGV Temperature Control. The IGV's should remain at a fixed minimum value from full speed no load until the turbine incrases load while on the exhaust temperature contro curve. The IGV's open from their minimum value as the turbine increases load while on the exhaust temperature control curve until they reach a maximum at Base Load.

IGV Temperature Control is defaulted to be "on", but the operator should always check this during startup. The only exception to this rule is when temperature matching is selected (see Temperature Matching below), or simple cycle IGV control is selected. Simple Cycle IGV control can be selected between breaker closer and 8 MW, or at Full open IGV's.

f. Inlet Heating

Operation of the gas turbine with reduced minimum IGV settings can be used to extend the Premix operating region to lower loads. Reducing the minimum IGV angle allows the combustor to operate near a constant firing temperature that is high enough to support Premix operation while maintaining a sufficient fuel to air ratio.

Inlet heating through the use of recirculated compressor discharge airflow is necessary when operating with reduced IGV angles in order to protect the turbine compressor. Inlet heating protects the turbine compressor from stall by relieving discharge pressure and by increasing the inlet air stream temperature. Also, inlet heating prevents ice formation due to increased pressure drop across the reduced IGV angle.

The inlet heating system regulates the compressor discharge bleed flow through a control vlave and into a manifold located in the compressor inlet air stream. The control valve varies the inlet air flow as a function of the IGV angle, compressor operating and ambient temperature.

g. Temperature Matching

Temperature matching is used when the gas turbine exhaust temperature is to be controlled to bring on a steam turbine. The operator must select temperature matching "on". Once selected, the turbine has to be loaded/unloaded to the matching window. Once the unit is in the matching window, the operator can enable matching with temperature matching on the Gas Turbine Exhaust temperature can be increased using the targets on the Temperature Matching Control Screen.

h. DLNx II Display Messages

The following display messages will appear on the control panel CRT in order to inform the operator of the current combustion mode of operation:

Primary Mode

Lean–Lean Mode

Secondary Prefill

Piloted Premix Mode

Premix Transfer Mode

Premix Steady State

Tertiary only FSNL Mode

7. Water Washing System Operation (Optional)

a. General

Water washing should be scheduled during a normal shutdown, if possible. This will allow enough time for the internal machine temperature to drop to the required levels for the washing. The time required to cool the machine can be shortened by maintaining the unit at crank speed. During this cooling of the turbine, the wash water is to be heated to the proper level.

b. Mandatory Precautions

Before water washing of the compressor begins, the turbine blading temperature must be low enough so that the water does not cause thermal shock.

CAUTION

The differential temperature between the wash water and the interstage wheelspace temperature must not be greater than 120°F (48.9°C) to prevent thermal shock to the hot gas parts. For wash water of 180°F (82.2°C), the maximum wheelspace temperature must be no greater than 300°F (148.9°C) as measured by the digital thermocouple readout system on the turbine control panel.

To reduce this difference, the wash water may be heated and the turbine kept on crank until the wheelspace temperatures drop to an acceptable level. The wheelspace temperatures are read in the control room on the <I> CRT.

CAUTION

If, during operation, there has been an increase in exhaust temperature spread above the normal 15°F to 30°F (8.3°C to 16.6°C), the thermocouples in the exhaust plenum should be examined. If they are coated with ash, the ash should be removed.Radiation shields should also be checked.

If they are not radially oriented relative to the turbine, they should be repositioned per the appropriate drawing. If the thermocouples are coated with ash, or if the radiation shields are not properly oriented, a correct temperature reading will not be obtained.

If neither of the above conditions exists and there is no other explanation for the temperature spread, consult the General Electric Installation and Service Engineering representative.

WARNING

The water wash operation involves water under high pressure. Caution must be exercised to ensure the proper positioning of all valves during this operation. Since the water may also be hot, necessary precautions should be taken in handling valves, pipes, and potentially hot surfaces.

Note: **Before water washing the compressor, inspect the inlet plenum and gas turbine bellmouth for large accumulations of atmospheric contaminants which could be washed into the compressor. These deposits can be removed by washing with a garden hose.**

c. Water Wash Procedures

Refer to cleaning publication included in this section for details on procedure.

8. Unit Operation After Failure to Fire on Liquid Fuel (DLN 2.0 or DLN 2.6)

The following only applies to units with DLN 2.0 or DLN 2.6 combustion systems. After every failure to fire on oil, a STOP command should be given and the unit allowed to decelerate to 2% speed and operate there for at least 2 minutes before being restarted on gas or liquid fuel. Currently, this must be done manually. This operation allows excess liquid fuel to drain from liners.

IV. DESCRIPTION OF PANELS AND TERMS

A. Turbine Control Panel (TCP)

The turbine control panel contains the hardware and software required to operate the turbine. A front elevation view of the panel can be seen in the Hardware Description.

EMERGENCY STOP (5E) — This red pushbutton is located on the front of the TCP. Operation of this pushbutton immediately shuts off turbine fuel.

BACKUP OPERATOR INTERFACE (BOI) — This interactive display is mounted on the front of the TCP. All operator commands can be issued from this module. In addition, alarm management can be performed and turbine parameters can be monitored from the <BOI>.

B. <I> CRT

The <I> CRT is a personal computer that directly interfaces to the turbine control panel. This is the primary operator station. All operator commands can be issued from the <I> CRT. Alarm management can be performed and turbine parameters can be monitored. With the proper password, editing can also be accomplished.

1. Main Display

Operator selector targets and master control selector targets can be actuated from the main display by using the cursor positioning device (CPD). Operator selector targets include:

OFF — Inhibits a start signal.

CRANK — With crank selected, a start signal will bring the machine to purge speed.

FIRE — With FIRE selected, a START signal will bring the machine to minimum speed and establish flame in the combustors. Selecting FIRE while the machine is on CRANK will initiate the firing sequence and establish flame in the combustors.

AUTO — With AUTO selected, a START signal will bring the machine to operating speed. Changing selections from FIRE to AUTO will allow the machine to accelerate to operating speed.

REMOTE — With REMOTE selected, control for the unit is transferred to the remote control equipment.

Master control selector targets include:

START — A START selection will cause the unit to start. With AUTO selected, the unit will load to the SPINNING RESERVE load point.

FAST START - A FAST START selection will cause the unit to start. With AUTO selected, the unit will load to the PRESELECTED load point. The machine will load at the manual loading rate.

STOP - A STOP selection will cause the unit to initiate a normal shutdown.

All operator selector switches and master control selector targets are green and are located on the right side of the display. All green targets are the AUTO/EXECUTE type, which means that the target must be selected with the CPD and then, within three seconds, the EXECUTE target at the bottom of the display must also be selected in order to actuate that command.

2. Load Control Display

Load selector targets can be actuated from the load control display by using the cursor positioning device (CPD). Load selector targets include:

PRESEL - Select the preselected load point.

BASE - Select base temperature control load point.

*PEAK - Select peak temperature control load point.

3. *Fuel Mixture Display

Fuel selector targets are used to select the desired fuel by using the cursor positioning device (CPD). Fuel selector targets include:

GAS SELECT - 100% gas fuel operation.

DIST SELECT - 100% distillate fuel operation.

MIX SELECT - Selecting MIX while on 100% single fuel will cause the machine to transfer to mixed fuel operation at a preset mixture (not applicable on DLN units).

4. *Isochronous Setpoint Display

Governor selector targets are used to select the desired type of speed control by using the cursor positioning device (CPD). Governor selector targets include:

DROOP SELECT - Used to select droop speed control.

ISOCH SELECT - Used to select isochronous speed control.

5. *Inlet Guide Vane Control Display

The inlet guide vane (IGV) temperature control targets are IGV TEMP CNTL ON and IGV TEMP CNTL OFF. The IGV AUTO target selects normal operation of the IGVs. The IGV MANUAL target allows the maximum IGV angle to be manually set by the operator (not normally used while on–line).

6. Alarm Display

This screen displays the current un–reset alarms, the time when each alarm occurred, the alarm drop number and a word description of the alarm. An "*" indicates that the alarm has not been acknowledged. The "*" disappears after the alarm has been acknowledged. For more information, see the Mark V Users' Manual (GEH–5979).

7. Auxiliary Display

COOLDOWN ON and COOLDOWN OFF can be selected from this display.

8. Manual Reset Target

Selecting the manual reset target resets the Master Reset Lockout function. This target must be selected so that the unit can be restarted following a trip.

C. Definition of Terms

SPINNING RESERVE - The minimum load control point based on generator output. The spinning reserve magnitude in MWs can be found in the control specifications (5–10% of rating is a typical value).

PRESELECTED LOAD - A load control point based on generator output. The preselected load point is adjustable within a range designated in the Control Specification. The preseelected load point is normally set below the base load point (50–60% of rating is a typical value).

BASE LOAD - This is the normal maximum loading for continuous turbine operation as determined by turbine exhaust temperature levels.

PEAK LOAD (Optional) - This is the maximum allowable output permitted for relatively long–duration, emergency power requirement situations consistent with acceptable turbine parts life. Peak loading duration is based on turbine exhaust temperature levels.

D. Generator Control Panel (Typical)

SYNCHRONIZING LAMPS — Rough indication of the speed and phase relationship between the generator and the bus.

FREQUENCY METER — Indicates generator frequency.

INCOMING VOLTMETER — Indicates generator voltage.

RUN VOLTMETER — Indicates bus voltage.

SYNCHROSCOPE — Indicates the phase relationship between the generator and bus voltage.

GENERATOR AMMETER — Indicates generator phase current. The phase current to be read is selected on the three position ammeter selector switch.

GENERATOR WATTMETER — Indicates the generator output in megawatts.

GENERATOR VARMETER — Indicates the generator reactive output in megavars.

GENERATOR TEMPERATURE METER — (Traditionally included on the Generator Control Panel, but actually displayed in Mark V SPEEDTRONIC® systems on the <I> CRT.) Reads the generator Resistance Temperature Detector (RTD) selected by the temperature meter selector switch.

EXCITER VOLTMETER — Indicates generator field voltage (if used).

GENERATOR FIELD AMMETER — Indicates generator field amperes (if used).

AMMETER SELECTOR SWITCH — See Generator Ammeter (above).

SYNCHRONIZING SELECTOR SWITCH (43S/CS) — Three position switch used to select the synchronizing mode.

Manual — Selects manual synchronizing mode. In this position the generator frequency and voltage, bus voltage, and phase relationship will be displayed to facilitate manual synchronizing.

Off/Remote — Used when the unit is being controlled from the remote control equipment.

Auto — Used for local automatic synchronizing.

VOLTMETER SWITCH (VS) — Used to select the phase of the bus voltage to be displayed on the run voltmeter.

TEMPERATURE METER SELECTOR SWITCH — Traditionally included on the Generator Control Panel, but actually displayed in Mark V SPEEDTRONIC® systems on the <I> CRT.

VOLTAGE/VAR CONTROL SWITCH (90R4/CS) — Controls generator voltage when the unit is off the line, and controls voltage/vars when the machine is on the line. (Increase — Right; Decrease — Left; spring return to normal.)

GENERATOR BREAKER CONTROL SWITCH (52G/CS) — Used to open or close the generator breaker. The indicator lights above the switch indicate Open (Green) and Closed (Red).

Note: Using this switch, the generator breaker should be closed only when proper synchronizing techniques are used or when the system onto which the generator is being brought is not energized.

GENERATOR DIFFERENTIAL LOCK-OUT SWITCH (86G) — Manual reset lockout switch which operates in the event of a generator fault.

GOVERNOR RAISE/LOWER CONTROL SWITCH (70R4/CS) — Used to control turbine speed when the generator is off the line (i.e. for manual synchronizing); generator load when the generator is on the line; and frequency when the generator is running isolated and on DROOP speed control.

TRANSFORMER DIFFERENTIAL LOCK-OUT SWITCH (86T) — Manual reset lockout switch which operates in the event of a transformer fault.

WATTHOUR METER — Measures the watthour output of the generator.

E. Motor Control Center

The turbine is provided with a motor control center for the control of the electrical auxiliaries. The motor control center includes AC and DC distribution systems.

Motor controllers are used for auxiliaries such as motors and heaters. Each motor controller normally consists of a breaker, control power transformer, control circuit, power contactor, selector switch and indicator lights. The selector switch is normally left in AUTO. Each motor control center is also provided with AC and DC distribution panel boards with circuit breakers.

F. Supervisory Remote Equipment

Supervisory equipment is normally functionally the same as the equipment described in the cable connected master panel. However, it may differ somewhat in metering and indications. Refer to the supervisory manufacturer's instruction manual for details.

G. Annunciator System

Alarms are displayed on the <I> CRT when the ALARM Display mode is selected. Before clearing an alarm, action should be taken to determine the cause and perform the necessary corrective action. The following is a list of annunciator messages along with suggested operator action.

Note: **The alarm messages can be categorized as either "trip" or "alarm". The "trip" messages contain the word TRIP in the message. The "alarm" messages do not indicate TRIP. For those alarms associated with permissive to start and trip logics latched up through the MASTER RESET function, it will be necessary to call up the <I> CRT Display with the Master Reset target in order to unlatch and clear these alarms.**

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INTEROFFICE MEMORANDUM

Date: 07-Jun-1999 09:32am
From: Mike Halpin TAL
HALPIN_M
Dept:
Tel No:

To: Alvaro Linero TAL (LINERO_A)

Subject: JEA - Brandy Branch

Al -

You may get a call from Bert with JEA. I had asked them a question (No. 9 of attached) which they apparently do not wish to answer. According to Chris Carlson who spoke with Bert last week, they said that they would "provide this additional information on the side, but do not wish to slow down the process". I would appreciate it if you would support me in the event JEA contacts you to get relief on this point.

Thanks
Mike

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

May 26, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. N. Bert Gianazza, P.E.
Jacksonville Electric Authority
21 West Church Street
Jacksonville, FL 32202-3139

Re: Request for Additional Information
DEP File No. 0310485-001-AC (PSD-FL-267)
Brandy Branch Facility - Three 170 MW Combustion Turbines

Dear Mr. Gianazza:

On May 18, the Department received your application and complete fee for an air construction/operation permit for three 170-MW dual fuel, proposed 'F' class combustion turbines for the Brandy Branch Facility in Duval County. The application is incomplete. In order to continue processing your application, the Department will need the additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. As indicated in the application, a recent BACT determination of General Electric simple cycle CT's for the Oleander Project resulted in NO_X emissions of 9 ppm. Please provide specific information on what costs are required in order to obtain a guarantee of 9 ppm as was provided for in that application.
2. If costs were incurred to obtain a guarantee of 12 ppm from a higher level (e.g. 15 ppm), please provide that information.
3. Please explain why the "inlet bleed" data sheets show NO_X emissions on gas at 15 ppmvd.
4. Please provide the rationale for the 15 ppmvd @ 15% O_2 limit proposed for CO as BACT for natural gas firing. The combustors typically achieve 12 ppm of CO.
5. Please explain why 26.00 ppm CO while firing oil is shown as the "Requested Allowable Emissions and Units" within each CT's Section H. Most other documentation indicates 20 ppm.
6. Please submit overlays (isopleths) of the maximum ground-level concentrations of NO_X, PM/PM_{10}, CO, and SO_2 with respect to residential communities up to 2 miles (3.2 kilometers) from the proposed site.
7. Please provide a detailed map showing the location of all of the sources and fence-line receptors used in the air quality impact analysis. These source and receptor locations should be shown in UTM coordinates since the UTM coordinate system is used in the modeling. In addition send us diskettes containing all of the air quality impact analysis modeling output files.
8. How will fuel oil be delivered to the site, e.g. pipeline or trucks? If by truck, please estimate the average number of daily deliveries.

9. Please re-examine the use of fuel oil as a back-up fuel. Provide an evaluation of 0, 1 and 2 CT's simultaneously combusting fuel oil and the corresponding effects on the Class I Significant Impact Levels for SO_2.
10. Provide the worst case start-up and shutdown emissions characteristics for the units under consideration including start-up curves and duration of excess emissions. The Department plans to address excess emissions in its BACT determination.

We are awaiting comments from the EPA and the National Park Service. We will forward them to you when received and they will comprise part of this completeness review.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): *"The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."*

If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9530. Matters regarding review of the modeling should be directed to Chris Carlson (meteorologist) at 850/921-9537.

Sincerely,

5/26

A.A. Linero, P.E. Administrator
New Source Review Section

AAL/mph

cc: Gregg Worley, EPA
Mr. John Bunyak, NPS
James L. Manning, P.E. RESD
Chris Kirts, DEP-NED
Anthony L. Compaan, P.E., Black & Veatch

Z 333 618 154

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Bert Gianazza
Street & Number JEA
Post Office, State, & ZIP Code Jax Fl

Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$

Postmark or Date 5-26-99
C310485-001-AC
PSD-FI-267

PS Form **3800**, April 1995

Fold at line over top of envelope to

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Bert Gianazza, PE
JEA
21 W. Church St.
Jacksonville, Fl
32202-3139

4a. Article Number
Z 333 618 154

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery 5-28-99

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X D. Moe

Is your RETURN ADDRESS completed on the reverse side?

Thank you for using Return Receipt Service.

PS Form **3811**, December 1994 102595-97-B-0179 Domestic Return Receipt

BLACK & VEATCH

8400 Ward Parkway, P.O. Box 8405, Kansas City, Missouri 64114, (913) 458-2000

JEA
Brandy Branch Project
Letter Number L011

B&V Project 60903
B&V file 32.0203
May 25, 1999

RECEIVED

MAY 26 1999

**BUREAU OF
AIR REGULATION**

Mr. Al Linero, P.E.
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Mail Stop 5505

Dear Mr. Linero:

On behalf of the Jacksonville Electric Authority (JEA), Black & Veatch is pleased to submit the enclosed CD-ROM and computer diskette containing the Prevention of Significant Deterioration Air Permit Application air dispersion modeling files and the Electronic Submittal of Application (ELSA) file for the Brandy Branch Facility. Please forward these diskettes to the appropriate parties for review. The complete permit application, with the exception of these computer disks, was previously submitted to you on May 17, 1999.

If you have any questions concerning the permit application or these computer disks, please do not hesitate to call Bert Gianazza at JEA at (904) 665-6247, or me at (913) 458-7961.

Very truly yours,

BLACK & VEATCH

Mark J. Bareta
Air Quality Scientist

mjb

cc: File

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

May 20, 1999

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region IV
61 Forsyth Street
Atlanta, Georgia 30303

Re: Jacksonville Electric Authority – Brandy Branch Project
0310485-001-AC, PSD-FL-267

Dear Mr. Worley:

Enclosed for your review and comment is an application for the above mentioned project. It consists of three simple cycle intermittent duty combustion turbines. The units are 170 megawatt General Electric PG7241FA combustion turbines with Dry Low NOx combustors.

Your comments can be forwarded to my attention at the letterhead address or faxed to me at (850)922-6979. If you have any questions, please contact Mike Halpin at (850)921-9530.

Sincerely,

5/20

A. A. Linero, P.E.
Administrator
New Source Review Section

AAL/kt

Enclosures

cc: Mike Halpin, BAR

Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

May 20, 1999

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Section
NPS-Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

Re: Jacksonville Electric Authority – Brandy Branch Project
0310485-001-AC, PSD-FL-267

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for the above mentioned project. It consists of three simple cycle intermittent duty combustion turbines. The units are 170 megawatt General Electric PG7241FA combustion turbines with Dry Low NOx combustors.

Your comments can be forwarded to my attention at the letterhead address or faxed to the Bureau at (850)922-6979. If you have any questions, please contact Mike Halpin at (850)921-9530.

Sincerely,

5/20

A. A. Linero, P.E.
Administrator
New Source Review Section

AAL/kt

Enclosures

cc: Mike Halpin, BAR