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Department of
Environmental Protection

Jeb Bush
Governor

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3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

July 29, 2003

- CERTIFIED MAIL - RETURN RECEIPT REQUESTED -

Laura R. Crouch
Manager, Air Programs
Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601-0111

RECEIVED
AUG 5 2003
ENVIRONMENTAL AFFAIRS

RE: **Tampa Electric Company Big Bend Unit 4**
Modification to Conditions of Certification
DEP Case Number PA 79-12L
OGC Case Number 03-0413

ORDER MODIFYING CONDITIONS OF CERTIFICATION

Dear Ms Crouch:

On July 26, 2001, the Department issued Final Title V Operation Permit Revision No. 0570039-010-AV for the Tampa Electric Company Big Bend Unit 4. That permit revision authorized Big Bend Unit 4 to include petroleum coke as a fuel with limitations on the vanadium content and ash content of the petroleum coke. The permit revision also included revised operating, monitoring and reporting conditions to reflect the use of petroleum coke. Pursuant to Rule 62-17.211(4), Florida Administrative Code (F.A.C.) the Department proposes to modify the Conditions of Certification for this facility to conform them to the Title V Permit.

On June 9, 2003, all parties to the certification proceeding were provided with notice by certified mail of the Department's intent to modify the Conditions of Certification for this facility, along with a copy of the proposed Order Modifying Conditions of Certification. Additionally, on June 27, 2003, notice of the Department's intent to modify the Conditions of Certification for this facility was published in the Florida Administrative Weekly ("FAW"), and on the Department's internet home page at http://www.dep.state.fl.us/ under the link or button titled "Official Notices." Those notices specified that pursuant to Section 403.516, Florida Statutes ("F.S."), and Rule 62-17.211, F.A.C., all parties to the certification proceeding have 45 days from the issuance of the notice by mail to such party's last address of record in which file a written objection to the modification; that any person who is not already a party to the certification proceeding and whose substantial interests will be affected by the requested modification has 30 days from the date of publication of the public notice in the FAW to object in writing; that failure to act within the time frame constitutes a waiver of the right to become a party; and that the Department will issue a Final Order Modifying the Conditions of Certification for this facility if no written objections are received by the Department.

No objections to the modification have been received by the Department. The Conditions of Certification for the Tampa Electric Company Big Bend Unit 4 are hereby modified as follows:

I. Air

The construction and operation of Big Bend Unit 4 at the Tampa Electric Company steam electric power plant site shall be in accordance with all applicable provisions of Chapters 62-4, 62-210, 62-212, 62-213, 62-214, 62-256, 62-257, 62-296, 62-297, 62-302, and 62-701, Florida Administrative Code. In addition to the foregoing, the permittee shall comply with the following conditions of certification:

A. Emission Limitations

1. Based on a maximum heat input of 4,330 million BTU per hour, stack emissions from Big Bend Unit 4 (Emission Unit 004) shall not exceed the following when burning coal or a coal/petroleum coke blend:

a. SO_2 - ~~1.2 lb. per million BTU heat input, maximum two hour average, 0.84 lb/MMBtu on a 30-day rolling average.~~ Sulfur dioxide emissions from Unit No. 4 when combusting solid fuel shall not exceed 0.82 lb/million Btu heat input and 10 percent of the potential combustion concentration (90 percent reduction). Based upon a heat input of 4330 million Btu/hour, SO_2 emissions shall not exceed 3551 lb/hr. Compliance with sulfur dioxide emission limitations and percent reduction requirements is determined on a 30-day rolling average basis. The sulfur dioxide emission standards apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the following procedures in specific condition I.A.15. are implemented.

b. NOx - 0.60 lb. per million BTU heat input. Nitrogen dioxide emissions from Unit No. 4 when combusting bituminous or anthracite coal, or a coal/petroleum coke blend, shall not exceed 0.60 lb/million Btu heat input. Based upon a heat input of 4330 million Btu/hour, NO_x emissions shall not exceed 2598 lb/hr. These emission limits are based on a 30-day rolling average. These standards apply at all times except during periods of startup, shutdown, or malfunction.

c. Particulates - 0.03 lb. per million BTU heat input. This standard applies at all times except during periods of startup, shutdown, or malfunction. Based on the maximum permitted heat input rate listed in Specific Condition I.A.1., particulate matter emissions from Unit No. 4 shall not exceed 129.9 lbs/hour, 3118 lbs/day, and 569.0 tons/year.

d. No change

e. Carbon monoxide (CO) emissions from Unit No. 4 shall not exceed 0.029 lb/million Btu heat input, and shall not exceed 124 lb/hr.

2. through 9. No change

10. Operation ~~Coal should not be burned in the unit unless both electrostatic precipitator and limestone scrubber are operating properly.~~

~~11. Coal burned in the unit should be washed before it is transported to the plant site.~~

~~12. Fuels fired shall consist of coal or a coal/petroleum coke blend containing a maximum of 20.0 percent petroleum coke by weight. The sulfur content of the petroleum coke shall not exceed 6.0 percent by weight (dry basis). Vanadium content of the mineral ash from the petroleum coke fired shall not exceed 35.0 percent by weight (ignited basis).~~

a. Normal operation: The only fuels fired in Unit No. 4 shall be coal or a coal/petroleum coke blend containing a maximum of 20.0% petroleum coke by weight. The vanadium content of the petroleum coke fired shall not exceed 2660 ppm. The ash content of the petroleum coke fired shall not exceed 0.76% by weight on a dry basis. The permittee shall maintain and submit to the Department, and to the Environmental Protection Commission of Hillsborough County, on an annual basis for the years 2001, 2002, 2003, 2004, and 2005 data demonstrating that removal of the sulfur content limit and the revision of the vanadium content limit in the petroleum coke fired did not result in a significant increase in the representative actual annual emissions of any regulated pollutant.

b. Other operation: In addition to the fuels allowed to be burned during normal operation, Unit No. 4 may also burn new No. 2 fuel oil during startup, shutdown, flame stabilization and during the start of an additional solid fuel crusher on an already operating unit. Evaporation of up to 150,000 gallons per year, total at the facility, is allowed of non-hazardous, but potentially HAP-emitting, mineral acid solution boiler chemical cleaning waste which was generated on site.

c. Coal shall not be burned in Unit No. 4 unless both the electrostatic precipitator and limestone scrubber are operating properly.

d. No change

e. TEC shall maintain a daily log of the amounts and types of fuels used and copies of fuel analyses containing information on sulfur content, ash content and heating values.

11. Tampa Electric Company is allowed to divert and integrate all of the flue gas from Unit No. 3 for purposes of treating that flue gas in the existing Unit No. 4 flue gas desulfurization (FGD) system.

12. Unit No. 4 is allowed to operate continuously, i.e., 8760 hours/year.

13. and 14. No change.

15. During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:

a. No change

b. Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation, and

c. Operating a spare flue gas desulfurization system module. The Department or EPCHC may at their discretion require TEC within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements of specific conditions I.A.1.a. and I.A.1.c. for any period of operation lasting from 24 hours to 30 days when:

(1) Any one flue gas desulfurization module is not operated,

(2) The affected facility is operating at the maximum heat input rate,

(3) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and

(4) TEC has given the Department or EPCHC at least 30 days notice of the date and period of time over which the demonstration will be performed.

B. Air Monitoring Program

1. The permittee ~~shall install and operate continuously monitoring devices for the Unit 4 boiler exhausts for sulfur dioxide, nitrogen dioxide, oxygen and/or carbon dioxide, and opacity. The monitoring devices shall meet the applicable requirements of Section 62-214, F.A.C., 40 CFR 60.47a, and 40 CFR 75. The opacity monitor may be placed in the ductwork between the electrostatic precipitator and the FGD scrubber.~~

a. When Units 3 and 4 are operating in the integrated mode (Unit 3 flue gasses routed through the Unit 4 FGD system), the continuous monitoring system will measure sulfur dioxide emissions at the inlet and outlet of the Unit 4 FGD system and from the Unit 3 stack, while emissions of nitrogen dioxides, oxygen and/or carbon dioxide, and opacity shall be measured in the Unit 4 duct prior to the FGD system.

b. When Units 3 and 4 are not operating in the integrated mode, the continuous monitoring system will measure only Unit 4's inlet duct and stack for SO_2 emissions. The emissions of nitrogen oxides, oxygen and/or carbon dioxide, and opacity shall be measured in the Unit 4 duct prior to the FGD system.

2. through 5. No change

6. TEC shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Department and the Environmental Protection Commission of Hillsborough County [EPCHC]).

7. TEC shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions as follows:

a. Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.

b. An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19, Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates, may be used to determine potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required in the preceding specific condition I.B.7.a.

8. TEC shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere.

9. TEC shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen and/or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored. The sulfur dioxide, nitrogen dioxide, oxygen and/or carbon dioxide, and opacity

monitoring devices shall meet the applicable requirements of Section 62-214, F.A.C., 40 CFR 60.47a., and 40 CFR 75.). The opacity monitor shall be placed in the duct work between the electrostatic precipitator and the FGD scrubber. When Units 3 and 4 are operating in the integrated mode (Unit 3 flue gases routed through the Unit 4 FGD system), the continuous monitoring system will measure sulfur dioxide emissions at the inlet and outlet of the Unit 4 FGD system and from the Unit 3 stack (CS002), while emissions of nitrogen oxides, oxygen and/or carbon dioxide, and opacity shall be measured in the Unit 4 duct prior to the FGD system. When Units 3 and 4 are not operating in the integrated mode, the continuous monitoring system will measure only Unit 4's inlet duct and stack for SO_2 emissions. The emissions of nitrogen oxides, oxygen and/or carbon dioxide, and opacity shall be measured in the Unit 4 duct prior to the FGD system.

10. The continuous monitoring systems required in specific conditions B.7., B.8., and B.9., shall be operated and record data during all periods of operation of Unit No. 4 including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

11. TEC shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, TEC shall supplement emission data with other monitoring systems approved by the Department or the EPCHC, or the reference methods and procedures as described in Specific Condition B.13.

12. The 1-hour averages required under 40 CFR 60.13(h), *Monitoring Requirements*, are expressed in lbs/million Btu heat input and used to calculate the average emission rates required in specific conditions B.13. and B.14. The 1-hour averages are calculated using the data points required under 40 CFR 60.13(b), *Monitoring Requirements*. At least two data points must be used to calculate the 1-hour averages.

13. When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in specific condition B.21., TEC shall use the following reference methods and procedures. Acceptable alternative methods and procedures are given in specific condition B.25.

a. Method 6 shall be used to determine the SO_2 concentration at the same location as the SO_2 monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

b. Method 7 shall be used to determine the NO_x concentration at the same location as the NO_x monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

c. The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O_2 or CO_2 concentration at the same location as the O_2 or CO_2 monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

d. The procedures in Method 19 shall be used to compute each 1-hour average concentration in 1b/million Btu heat input.

14. TEC shall use the following methods and procedures to conduct the monitoring system performance evaluations required under 40 CFR 60.13(c), *Monitoring Requirements*, and the calibration checks required under 40 CFR 60.13(d), *Monitoring Requirements*. Acceptable alternative methods and procedures are given in specific condition B.25.

a. Methods 6, 7, and 3B, as applicable, shall be used to determine O_2, SO_2, and NO_x concentrations.

b. SO_2 or NO_x (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, as applicable) under 40 CFR 60 Appendix B, Performance Specification 2.

c. The span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows.

Fossil Fuel	Span value for nitrogen oxides (ppm)
Solid	1,000

d. Reserved

e. For affected facilities burning fossil fuel alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions oil fuel, alone or in combination with non-fossil fuel, the span value of the fuel fired. [Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(i); 40 CFR 60.13; 40 CFR 60 Appendix A, Methods 3B, 6, and 7; 40 CFR 60 Appendix B, Performance Specification 2.]

15. TEC may use the following as alternatives to the reference methods and procedures specified in conditions B.23. and B.24.

a. For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24

1-hour averages. If Method 6A or 6B is used under Condition I.B.24., the conditions under 40 CFR 60.46(d)(1) apply; these conditions do not apply under condition I.B.23.

b. For Method 7, Method 7A, 7C, 7D or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be 1 hour.

c. For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.

d. No change.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(j); 40 CFR 60.46(d)(1), 40 CFR 60 Appendix A, Methods 3, 3A, 3B, 6, 6A, 6B, 6C, 7, 7A, 7C, 7D, and 7E]

16. In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of 40 CFR 60 or the methods and procedures as specified in conditions B.17. through B.20., except as provided in 40 CFR 60.8(b). 40 CFR 60.8(f) does not apply to specific conditions B.18 and B.19. for SO_2 and NOx. Acceptable alternative methods are given in specific condition B.20.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(a); 40 CFR 60.8]

17. TEC shall determine compliance with the particulate matter standards in specific condition B.5. as follows:

a. The dry basis F factor (O_2) procedures in Method 19 shall be used to compute the emission rate of particulate matter.

b. For the particular matter concentration, Method 5B shall be used after **wet** FGD systems.

(1) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160±14 °C (320±25 °F).

(2) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B shall be used to determine the O_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of all the individual O_2 concentrations at each traverse point.

c. Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(b); 40 CFR 60.11, 40 CFR 60 Appendix A, Methods 1, 3B, 5B, 9, and 19]

18. TEC shall determine compliance with the SO_2 standards in specific condition I.A.1.a. as follows:

a. The percent of potential SO_2 emissions (%Ps) to the atmosphere shall be computed using the following equation:

$$\%P_s = [(100 - \%R_f)(100 - \%R_g)]/100$$

where:

$\%P_s$ = percent of potential SO_2 emissions, percent.
$\%R_f$ = percent reduction from fuel pretreatment, percent.
$\%R_g$ = percent reduction by SO_2 control system, percent.

b. The procedures in Method 19 may be used to determine percent reduction ($\%R_f$) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and flyash interactions. This determination is optional.

c. The procedures in Method 19 shall be used to determine the percent SO_2 reduction ($\%R_g$ of any SO_2 control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19, may be used if the percent reduction is calculated using the average emission rate from the SO_2 control device and the average SO_2 input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

d. The appropriate procedures in Method 19 shall be used to determine the emission rate.

e. The continuous monitoring systems specified in conditions B.17. and B.19. shall be used to determine the concentrations of SO_2 and CO_2 or O_2. [Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a (c); 40 CFR 60 43a; 40 CFR 60.47a(b) and (d); 40 CFR 60 Appendix A, Method 19]

19. TEC shall determine compliance with the NOx standards in specific condition I.A.1.b. as follows:

a. The appropriate procedures in Method 19 shall be used to determine the emission rate of NOx.

b. The continuos monitoring systems specified in specific conditions B.18. and B.19. shall be used to determine the concentrations of NOx and CO_2 or O_2. [Rule 62-

204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(d); 40 CFR 60.44a; 40 CFR 60.47a(c); 40 CFR 60.47a(d)]

20. TEC may use the following as alternatives to the reference methods and procedures specified in condition B.17:

a. For Method 5 or 5B, Method 17 may be used at Unit No. 4 if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

b. The F_c factor (CO_2) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of 40 CFR 60.46(d)(1). The CO_2 shall be determined in the same manner as the O_2 concentration. [Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(e); 40 CFR 60.46(d)(1); 40 CFR 60 Appendix A, Methods 5, 5B, 17, and 19]

21. For sulfur dioxide, nitrogen oxides, and particulate matter emissions, the performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) shall be submitted to the Department and the EPCHC. [Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(a)]

22. For sulfur dioxide and nitrogen oxides the following information shall be reported to the Department and the EPCHC for each 24-hour period.

a. Calendar date.

b. The average SO_2 and NOx emission rates (lb/ million Btu heat input) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

c. Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

d. Identification of the boiler operating days for which pollutant or dilutent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification or not obtaining sufficient data; and description of corrective actions taken.

e. Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_x only), emergency conditions (SO_2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

f. Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

g. Identification of times when hourly averages have been obtained based on manual sampling methods.

h. Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

i. Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with 40 CFR 60 Appendix B, Performance Specifications 2 or 3.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(b); 40 CFR 60 Appendix B]

23. If the minimum quantity of emission data, as required by the emission monitoring specific conditions B.6. through B.15., is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of specific condition B.5. shall be reported to the DEP for that 30-day period:

a. The number of hourly averages available for outlet emission rates (n_o) and inlet emission rates (n_i) as applicable.

b. The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

c. The lower confidence limit for the mean outlet emission rate (E_o*) and the upper confidence limit for the mean inlet emission rate (E_i*) as applicable.

d. The applicable potential combustion concentration.

e. The ratio of the upper confidence limit for the mean outlet emission rate (E_o*) and the allowable emission rate (E_{std}) as applicable.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(c); 40 CFR 60 Appendix A, Method 19]

24. If any sulfur dioxide standards under specific condition I.A.1.a. is exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

a. Indicating if emergency conditions existed and requirements under specific condition B.14. were met during each period, and

b. Listing the following information:

(1) Time periods the emergency condition existed;

(2) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(3) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(4) Percent reduction in emissions achieved;

(5) Atmospheric emission rate (ng/J or lb/MMBtu) of the pollutant discharged; and

(6) Actions taken to correct control system malfunction.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(d); 40 CFR 60.43a; 40 CFR 60.46a(d)]

25. If fuel pretreatment credit is claimed toward the sulfur dioxide emission standards in specific condition B.7. TEC shall submit a signed statement:

a. Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of specific condition B.28. and Method 19 (Appendix A of 40 CFR 60); and

b. Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(e), 40 CFR 60.48a(c)]

26. For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(f)]

27. The owner or operator of the affected facility shall submit a signed statement indicating whether:

a. The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

b. The data used to show compliance was or was not obtained in accordance with approved methods and procedures of these conditions and is representative of plant performance.

c. The minimum data requirements have o have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

d. Compliance with the standards has or has not been achieved during the reporting period.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(g)]

28. For the purposes of the reports required under 40 CFR 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under specific condition B.6. Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(h)]

29. The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Department and the EPCHC for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(i)]

30. Gravimetric instrument data verifying that the 20.0% maximum petroleum coke content by weight has not been exceeded shall be maintained for five years and submitted to the Department and the EPCHC with each annual operating report. Also to be maintained and available for inspection shall be a daily record of operation showing the date, fuel used, mode of operation (integrated/non-integrated), and the duration of all startups, shutdowns and malfunctions. TEC shall maintain copies of fuel analyses containing information on sulfur content, ash content, and heating values.
[PSD-FL-040; Rules 62-4.070(3), 62-213.440(1)(b)2.b.. F.A.C., and Power Plant Siting Certification PA 79-12]

31. Pursuant to Rule 62-212.200(2)(d), F.A.C., the actual emissions of the No. 4 Unit shall equal the representative actual emissions as defined in 40 CFR

52.21(b)(33). TEC shall maintain and submit to the Department and the EPCHC on an annual basis for a period of 5 years from the date the unit begins firing petroleum coke, data demonstrating that the operational change did not result in an emissions increase.

II. – XXX. No change

Any party to the this Order has a right to seek judicial review of it pursuant to Section 120.68, Florida Statutes by filing a Notice of Appeal, pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection in the Office of General Counsel, 3900 Commonwealth Boulevard, M.S. 35, Tallahassee, Florida 32399-3000, and by filing a copy of the Notice of Appeal, accompanied by the applicable filing fees, with the appropriate District Court of Appeal. The Notice of Appeal must be filed within thirty days from the date this Order is filed with the Clerk of the Department of Environmental Protection.

Executed in Tallahassee, Florida.

Hamilton S. Oven

Hamilton S. Oven, P.E.
Administrator, Siting Coordination Office

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52 Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Landa Korakous 7/29/03
Clerk Date

CC:

Frank K. Anderson, Esquire
Cathy Bedell, Esquire
Lawrence N. Curtin, Esquire
Sara Fotopulos, Esquire
Stephanie G. Kruer, Esquire
Gwen L. Shofner, P.E.